University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program: **Master of Science in Petroleum Engineering** Specialization: **Drilling**	Spring semester, 2014 Open
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Thesis title: **Tools and Techniques to Minimize Shock and Vibration to the Bottom Hole Assembly**	
Credits (ECTS): **30**	
Key words: **Shock and Vibrations** **Bottom hole assembly** **Drilling dynamics** **AST** **Frank´s HI tool**	Pages: 124 + enclosure: 9 Stavanger, 13/06-2014

Acknowledgement

I would like to take this opportunity to thank several people for aiding me in the work with this thesis. First, I want to express my appreciation to my supervisor at the University of Stavanger, Bernt Sigve Ådnøy. He has been of great assistance by giving me continuous guidance and confidence in my work. I would also like to thank Espen Andreassen, my supervisor at Statoil, for giving me an interesting topic for my thesis. Despite being very busy in his position as Leading Advisor in Drilling, he always took time to guidance me when needed. His knowledge and engagement in discussions were highly valuable and I enjoyed having him as my supervisor.

Throughout my work with this thesis I have been in contact with multiple people in the Norwegian oil industry. I would like to thank you all for your contribution. A special thanks goes to Remi Holand, Frank Johnsen and Richard Harmer who have willingly met with me, provided relevant information and good advice.

Finally, I would like to thank Statoil as an organization for giving me the opportunity to write this thesis. By writing this thesis for Statoil I have got access to information and experiences that I otherwise would not have received.

Abstract

When drilling a well there is a risk of serious damage caused by drillstring vibrations. Shock and vibration are identified as a cause of premature failure on drill bit and components in the bottom hole assembly (BHA), resulting in lost time for operators and costing service companies several millions in repair each year. The expenditures incurred by drillstring vibrations include reduced rate of penetration (ROP), tripping and poor drilling performance. Currently, several tools and techniques are used in the attempt to minimize shock and vibration. For vibration mitigation to be more effective in the future, the most effective tools and techniques must be designated, implemented and improved.

The main objectives of this thesis are to give an insight into the main vibration problem and determine effective mitigation tools and techniques, with regards to the BHA design, which can minimize shock and vibration, and improve the drilling performance in the future. A particular focus was given to anti-vibration tools, and vibration prevention in underreamer applications. The thesis is divided into four main parts; theory on drillstring vibrations, evaluation of various tools and techniques for vibration mitigation, including supplier input, a performance analysis of the Anti Stick-slip Technology (AST) and finally a discussion and conclusion part. Several field case studies are presented to illustrate how the tools and techniques can reduce the risk of detrimental vibrations.

The work is based on literature reviews and is substantiated by comparative field experiences. Additional information was acquired through conversations with Statoil, the directional drilling suppliers and tool suppliers. These conversations proved highly valuable and resulted in several proposed tools and techniques that should be considered when designing the BHA.

The thesis revealed that BHA design awareness can lead to huge advancements in terms of minimizing shock and vibration. Roller reamers should be added to the assembly if high stick-slip levels are expected or if the stabilizers experience extensive friction. Anti-vibration tools, such as AST and Frank´s Harmonic Isolation (HI) tool should be considered, as field experience indicates that these tools can reduce the vibration level. The results of the AST performance analysis indicated a 21% increase in ROP for runs including the tool. For underreamer operations a great potential exists in placing an expandable stabilizer above the underreamer. Another BHA alteration that should be considered is tapered stabilization, which can lead to fewer twist-offs in large hole sections. In the future, the industry must be willing to make changes in order to minimize shock and vibration. A constant push towards better procedures and innovative technology is needed.

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List of abbreviations

AST	Anti Stick-slip Technology
AVD	Active Vibration Damper
BB	Black Box
BHA	Bottom Hole Assembly
BP	British Petroleum
DBOS	Drill Bit Optimization System
DLS	Dogleg Severity
DMT	Dynamic Measuring Tools
DOC	Depth Of Cut
DOCC	Depth of Cut Control
GoM	Gulf of Mexico
HI	Harmonic Isolation
HWDP	Heavy Weight Drill Pipe
IRIS	Internal Research Institute of Stavanger
LWD	Logging While Drilling
MD	Measured Depth
MSE	Mechanical Specific Energy
MWD	Measurement While Drilling
NOV	National Oilwell Varco
NPT	Non-Productive Time
OD	Outer Diameter
OOS	Out Of Specification
PDC	Polycrystalline Diamond Compact
POOH	Pull Out Of Hole
RC	Roller Cone
RMS	Root Mean Square
ROP	Rate Of Penetration
RPM	Revolutions Per Minute
RSS	Rotary Steerable System
RWD	Reaming While Drilling
SPE	Society of Petroleum Engineers
TD	Target Depth
WDP	Wired Drill Pipe
WOB	Weight On Bit

Nomenclature

A	Cross sectional area	m^2 (ft^2)
D	Outer diameter, drillcollar	m (ft)
d	Inner diameter, drillcollar	m (ft)
E	Modulus of elasticity	$\frac{N}{m^2}$ (psi)
G	Shear modulus	$\frac{N}{m^2}$ (psi)
H	Depth of well	m (ft)
h	Lateral displacement	m (ft)
h_b	Height from bottom of well	m (ft)
h_p	Pitch of helix	
I	Moment of inertia, drillcollars	m^4 (ft^4)
J_T	Polar moment of inertia of the cross sectional area	m^4 (ft^4)
L	Height in circle segment	m (ft)
l_{dc}	Length of drillcollar section between stabilizers	m (ft)
l_f	Final length of rod	m (ft)
l_o	Original length of rod	m (ft)
N	Rotary speed	$\frac{rad}{s}$ (rpm)
P_m	Pump pressure	$\frac{N}{m^2}$ (psi)
R	Radius	m (ft)
ROP	Rate of penetration	m/hr (ft/hr)
S	Total axial force on drillcollar	kg (lb)
s	Original length in circle segment	m (ft)
T	Torque	kNm (lbf ft)
t	Thickness of mud assumed to move with the drillcollar	m (ft)
w	Weight per unit length of BHA	kg/m (lb/ft)
WOB	Weight on bit	kg (lb)

Θ	Twist	deg (rad)
ϕ	Angle	deg (rad)
ρ	Density	$\frac{kg}{m^3}$ (lb/ft^3)
ρ_{dc}	Density of drillcollars	$\frac{kg}{m^3}$ (lb/ft^3)
ρ_m	Density of mud	$\frac{kg}{m^3}$ (lb/ft^3)

1. Introduction

Throughout the years, the petroleum industry has sought to enhance technology and provide more efficient solutions to improve the drilling efficiency. The main goal is to drill the well as fast as possible and thereby secure economic drilling. This must be performed in a manner that does not damage the equipment or induce risk, while resulting in a wellbore of required quality.

The majority of wells drilled offshore experiences shock and vibration. Drillstring vibrations are identified as one of the most significant factors limiting ROP and footage improvements. Fast drilling may instigate the generation of downhole vibrations, leading to premature failure of downhole components and thereby increase the field development costs. The expenses associated with replacing damaged components, prolonged well construction time, fishing jobs, lost in hole situations and side tracks, provides a strong incentive to making drillstring vibrations a key issue in drilling optimization. In addition, vibrations will lead to wasted energy input. When vibrations are generated they will consume energy, and thereby prohibit efficient transference of energy to the bit. By minimizing or preventing shock and vibration, more energy is delivered to the bit and hence the energy losses goes down while the drilling rate goes up.

As drilling becomes more and more challenging and wells are drilled in hard and though conditions, it becomes increasingly difficult to maintain a high performance level with regards to drilling speed, tool reliability and drilling dynamics. In addition, higher drilling costs and more complex and expensive tools makes the need for improved drilling performance highly important. In an industry driven by maximizing the profit, understanding and mitigating vibrations has become a challenge of high focus. The industry strives to prohibit the dynamic dysfunctions caused by vibrations and has to a large extent achieved this. Several solutions have been developed to cope with the problem. However, there is still no operating practice or tool that can singularly eradicate vibrations.

A goal for Statoil is to secure optimal drilling performance and minimize costly rig days, and hence it is in the operator's best interest that mitigation actions that reduce the exposure to vibration risk are used. Newer contracts have built in mechanisms that reward failure free performance and high drilling efficiency. The directional drilling suppliers are therefore relatively free to choose the tools and techniques they believe will enhance the drilling performance. One of the main goals for the directional suppliers is to protect advanced equipment from overload and thus the suppliers will also benefit from effective vibration mitigation methods. In order to achieve the goals set by the operator and the suppliers, effective vibration mitigation procedures must be highlighted and implemented. In the future it is important that the suppliers are encouraged to use alternative techniques and that the industry is willing to test new tools and techniques, and not only rely on the procedures that have been used in the past.

This thesis will look into alternative technologies and modifications that should be made to the BHA, to minimize shock and vibration in the future. The goal of the thesis is to establish effective operating practices and improvement areas for Statoil and the directional suppliers. It will cover important aspects such as the types of vibrations suffered downhole, the reason for their occurrence and the consequences (Chapter 2). It will also include a suggestion to a vibration mitigation workflow (Chapter 3), which should be applied to ensure that shock and vibration are given sufficient attention in all phases of the drilling operations. In later sections the best means of vibration mitigation in terms of BHA design will be discussed, to shed light on tools and techniques that can reduce the occurrence of detrimental vibrations. To quantify the effect of the AST tool on ROP, a performance analysis has been performed in Chapter 7. Finally, in Chapter 8 the most important findings will be discussed, and the risk and benefit trade-offs for each technique will be addressed.

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2. Theory

2.1 What are drillstring vibrations?

Downhole vibrations are separated into three primary classifications, axial, torsional and lateral/transverse. These three vibration modes have different vibrational patterns, are generated by different sources and lead to different problems with varying severity. Combinations and interactions of these motions can exist, increasing the complexity of the vibration motions. At low level, the vibrations are harmless. However, in severe cases, drillstring vibrations caused by one or a combination of these modes can have catastrophic consequences. Proper identification of the vibration modes is essential to understand which mitigation measure that must be undertaken.

2.1.1 Axial vibrations

Axial vibrations of a drillstring have been well studied and documented throughout the years. As shown in figure 1, this mode of vibration generates vibrations in the direction along the axis of the drillstring, i.e. in the wellbore direction. Axial vibrations are caused by the movement of the drillstring, upwards and downwards, and may induce bit bounce. Bit bounce is seen when large weight on bit (WOB) fluctuations causes the bit to repeatedly lift off bottom, in vertical direction along the drillstring, and then drop and impact the formation [1].

Figure 1: Axial vibration motion

Bit bounce and axial vibrations can lead to challenging drilling behaviour, resulting in damaged bit, reduced lifetime of the bit and decreased ROP [1]. Damaged components in the BHA have also been identified as a consequence of axial vibrations, and wear on bit and BHA leads to tripping, which is both time consuming and costly

Axial vibrations are damped by the drillstring itself due to the stiffness in the length direction and can be directly detected by the driller at shallow depths, as the vibrations travels to surface through the drillstring. This mode of vibration is considered less aggressive than the other modes and the recorded axial accelerations are usually significantly lower, due to the large masses that have to be set in motion [2].

The severity of axial vibrations is strongly affected by the interaction between the bit and the formation. Tricone bits have a tendency of creating bit bounce, particularly in hard formations, and roller cone (RC) bits in general are believed to generate high axial vibration level. Tricone bits consist of three cones and are most often used when drilling the top sections. When the three cones move up and down together a three-lobe pattern is generated, forming irregularities on the bottom. The shape of the pattern can be compared to a sinusoidal curve. This irregularity, in the formation beneath the cones, will initiate axial vibrations when the cones interact with the underlying formation [3].

Real-time mitigation actions include adjusting the revolutions per minute (RPM) and WOB, by increasing the WOB and reducing the RPM, to change the drillstring energy. If this does not work, it is recommended to stop drilling to allow the vibrations to cease and thereafter start drilling with different parameters [4]. This must be done in correlation with the ROP, as WOB and RPM are the most highlighted parameters affecting the drilling speed. In extremely hard formations, it can be difficult to completely eradicate axial vibrations, as a minimum ROP is required and specified by the operator. A less aggressive bit should be considered as a possible mitigation measure

2.1.2 Torsional vibrations

As illustrated in figure 2, torsional vibrations are seen as twisting motions in the drillstring and the main mechanism for the creation of torsional vibrations is stick-slip. The vibrations are generated when the bit and drillstring is periodically accelerated or decelerated, due to frictional torque on the bit and BHA [1]. Torsional vibrations lead to irregular downhole rotations. Non-uniform rotation is developed when the bit becomes temporary stationary, causing the string to periodically torque up and then spin free. The severity of stick-slip will affect how long the bit stays stationary and consequently the rotational acceleration speed when the bit breaks free. The downhole RPM can become several times larger than the RPM applied at surface [5].

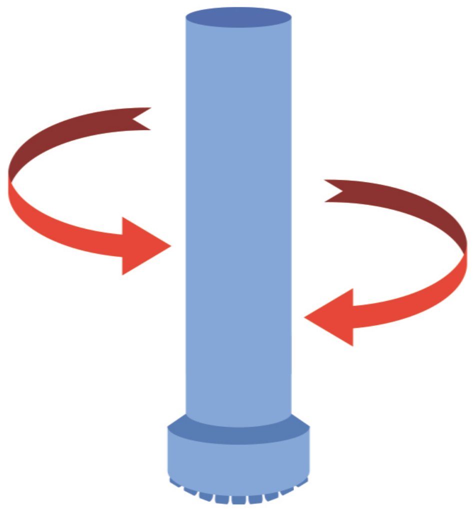

Figure 2: Torsional vibration motion

Torsional vibrations are highly damaging and are identified as one of the main causes of drillstring fatigue and bit wear. In severe cases, over-torqued connections and drillstring twist-offs have been observed. When this phenomenon occurs it consumes part of the energy originally dedicated to the ROP and it has been documented that stick-slip can lead to the ROP being decreased by 30-40% [1].

Stick-slip can either be caused by the rock-bit interaction or by the interaction between the drillstring and the borehole wall. The vibration mode is typically seen in environments such as high angle wells with long laterals and deep wells. Other factors, such as aggressive polycrystalline diamond compact (PDC) bits with high WOB, and hard formations or salt also seem to instigate the generation of stick-slip [6].

The drillstring is continuously experiencing some torsional vibrations, as the bit and drillstring are subjected to friction. Torsional vibrations are damped by the torsional stiffness of the drillstring and by the friction against the wellbore wall. The stiffness in torsional direction is not as significant as the stiffness in the length direction and hence the dampening is less pronounced than for axial vibrations. Due to the elasticity of the drillstring, the rotations will most often be irregular. A stiffer drillstring could potentially dampen the stick-slip indices. The vibration mode is observed at surface as large variations in torque values. Even in deviated wells, torsional vibrations can be detected by surface measurements and reduced by the driller [2].

The severity of torsional vibrations is dependent on both RPM and WOB, as for axial vibrations. The ideal RPM varies according to the conditions in the well. With higher WOB the possibility of stick-slip will increase, as the cutters will dig deeper into the formation and thereby increase the torque and side forces on the BHA. During drilling, the stick-slip level can be reduced by lowering the WOB and increasing the RPM [7].

2.1.3 Lateral/transverse vibrations

Lateral vibrations are seen as side-to-side motion in transverse direction relative to the string, illustrated in figure 3. The vibration mode is primarily generated by whirl. Whirl is the eccentric rotation of the drillstring, or part of it, around a point other than the geometric centre of the borehole. This motion will only occur if there is enough lateral movement in the BHA to bend out and touch the borehole wall. In severe cases it is known for triggering both axial and torsional vibrations, a phenomenon called mode coupling [1].

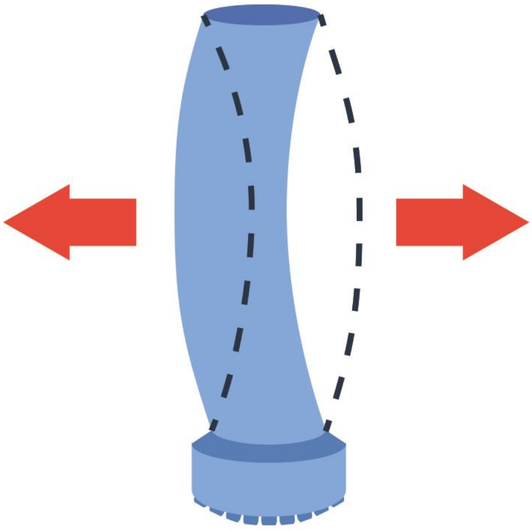

Figure 3: Lateral vibration motion

Transverse vibrations are viewed by the industry as the most destructive mode, entailing severe damage to the BHA components and wellbore, as the bit and BHA continuously impact the wellbore. The interaction between the bit/BHA with the wellbore wall leads to problems such as; overgauge holes, damaged equipment, lack of well direction control and drillstring fatigue.

The dampening of lateral vibrations is weak and caused by internal friction and surrounding drilling fluid. Transverse vibrations are not easily detected at surface, as the vibrations tend to dampen out, upwards along the string. This makes it difficult for the driller to detect them and perform preventive measures [2]. However, if lateral vibrations are recorded during drilling, the drilling parameters are adjusted to reduce the level of harmful vibrations. The RPM is often reduced, while the WOB is increased. If the vibrations continue, the assembly is picked of bottom, allowing the torque to unwind and the drilling restarts with different drilling parameters [4]. The energy imparted is also dependent on the free collar length and thus a shorter, stiffer BHA in lateral direction could be implemented to prevent sideways motion.

<u>Example 1: The effect of RPM and WOB on transverse vibrations</u>

In the following example the equations to determine the natural frequencies of a vibrating beam are presented. By applying the equations to a typical stabilized BHA one can see how the WOB and RPM will affect the resonance conditions. The main content of this example is taken from [8].

The following assumptions are made for these equations:

- No coupling to rotational and longitudinal vibrations
- Shear stresses are negligible
- The stabilizers are acting as perfect end conditions

When a beam with one end fixed and one end simply supported is subjected to axial force, S, the equation for angular frequencies of the vibration is given by:

$$p = k_i^2 \sqrt{\frac{EI}{\rho A}} \sqrt{1 - \frac{S}{k_i^2 EI}} \qquad \text{(Eq.1)}$$

To convert Eq. (1) to critical rotary speed, N, the following relationships are used:

$$N(rpm) = \frac{30}{\pi} p$$

$$k_i = \frac{3.927}{l_{dc}}$$

$$N = \frac{30}{\pi} \left(\frac{3.927}{l_{dc}}\right)^2 \sqrt{\frac{EI}{\rho A}} \sqrt{1 - \frac{S {l_{dc}}^2}{3.927^2 EI}} \qquad \text{(Eq.2)}$$

Assume that a mud layer of thickness t is vibrating along with the drillcollars. The total effective vibrating mass is given by:

$$\rho A = \rho_{dc} \frac{\pi}{4} (D^2 - d^2) + \rho_m \left(\frac{\pi}{4} d^2 + \pi D t\right) \qquad \text{(Eq.3)}$$

The compression load in the lower portion of the drillcollars may be expressed as:

$$S = WOB + 0.052 \rho_m H \frac{\pi}{4} (D^2 - d^2) - \frac{1}{2} P_m \frac{\pi}{4} d^2 - w h_b \qquad \text{(Eq.4)}$$

Numerical example:

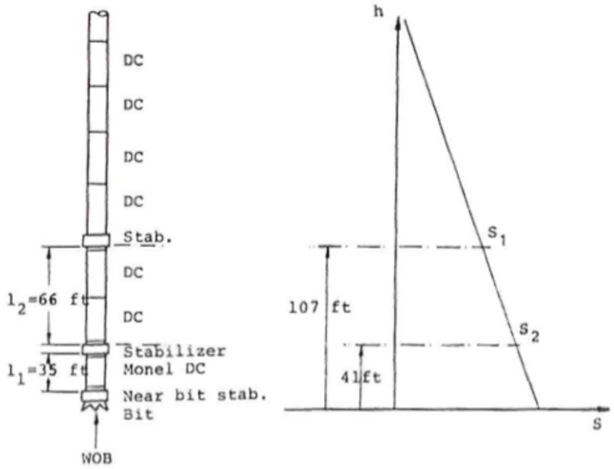

Figure 4: Composition of the numerical example [8]

l_2 will be evaluated in this example. From figure 4 it is seen that the compressive force at the top is S_1 and S_2 at the bottom.

- $\rho_m = 10ppg = 0.0433 lb/in^3$
- Drillcollar = 8in by $2\frac{13}{16}$in (D = 8in, d = $2\frac{13}{16}$in)
- $P_m = 3600psi$
- w = 150lb/ft
- h_b = 107ft (S_1) and 66ft (S_2)
- $\rho_{dc} = 0.28 lb/in^3$
- $t = 0.5in$
- l_{dc} = 66ft = 792in

S_1 *and* S_2 defines the outer limits for a loading band. If for a given RPM value the load falls within this band, resonance is likely to occur.

$$S_1 = WOB + 0{,}052 \times 10 \times Hx\frac{\pi}{4}\left(8^2 - \left(2\frac{13}{16}\right)^2\right) - \frac{1}{2} \times 3600 \times \frac{\pi}{4}\left(2\frac{13}{16}\right)^2 - 150 \times 107$$

$$S_2 = WOB + 22.91H - 27233 + 150 \times 66$$

$$S_1 = WOB + 22.91H - 27233\ (lb) \qquad \text{(Eq.5)}$$

$$S_2 = WOB + 22.91H - 17333\ (lb) \qquad \text{(Eq.6)}$$

The total effective vibrating mass for these numbers becomes:

$$\rho A = 0{,}28 lb/in^3 \times \frac{\pi}{4}\left(8^2 - \left(2\frac{13}{16}\right)^2\right) in^2 \frac{sec^2}{386in} + 0{,}0433 lb/in^3 \left(\frac{\pi}{4}\left(2\frac{13}{16}\right)^2 + \pi 8\frac{1}{2}\right) in^2 \frac{sec^2}{386in}$$

$$\rho A = \frac{1}{29.91} lb - sec^2/in^2 \tag{Eq.7}$$

Inserting Eqs. (5) through (7) and

$$E = 30 \times 10^6 psi\ (steel)$$

$$I = \frac{\pi}{64}\left(8^4 - \left(2\frac{13}{16}\right)^4\right) = 198in^4$$

into Eq. (2) the final equation becomes:

$$N_1 = 99\sqrt{1 - 6.85x10^{-6}(S_1 or S_2)} \tag{Eq.8}$$

The results of Eq. (8) are displayed in figure 5, illustrating the bands of transversal resonance for these specific numbers. The WOB is varied between 0 and 50000lb. If a given combination of H, N and WOB falls outside these bands there will be no resonance. For example, if H is 6000ft and the WOB is 10000lb we can calculate the critical RPM levels by inserting S_1 and S_2 into Eq. (8). We then find that the 10000lb band at 6000ft ranges from 33 to 41RPM. Assume we are drilling at 6000ft, the driller starts to rotate and gradually applies WOB. At 20RPM, the WOB is 10000lb and no resonance is present. Then, increasing both N and WOB a resonance band is entered. The 20000lb band ranges from 20 to 33RPM. Beyond 33RPM there is no possibility for resonance unless the WOB is reduced [8]. This example illustrates that both RPM and WOB will affect the generation of transversal vibrations and by staying within an optimal range of these parameters resonance conditions and detrimental vibrations can be avoided.

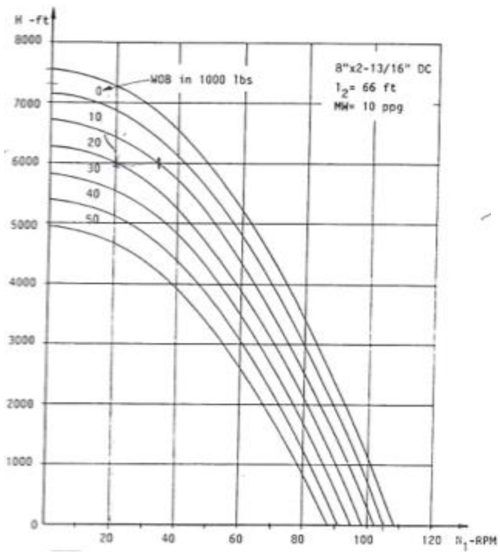

Figure 5: Regions of transversal resonance [8]

2.1.3.1 Bit whirl

If the bit creates a hole larger than its own diameter, bit whirl is initiated. Instead of the bit rotating around its natural centre of mass, it will move freely around the wellbore, creating an unusual pattern and high vibration tendencies. Bit whirl is typically generated due to significant side cutting on bits, softer formations and/or washed out formations [6].

The primary consequence of bit whirl is damage to the bit cutting structure. When whirling, the cutters move fast and uncontrolled backwards and sideways. The bit is subjected to high impact load and hence the cutters will chip, resulting in excessive wear. The whirling motion tends to lead to over gauge holes, reinforcing the tendency for the bit and BHA to whirl. In interbedded lithology with different comprehensive strength, friability ledges can be created, as weaker rocks will be enlarged to a greater diameter than stronger rocks, which will remain in gauge [6]. It is important to keep in mind that an overgauge hole can be present before whirl is initiated as well, increasing the likelihood of experiencing bit- and BHA whirl.

2.1.3.2 BHA whirl

The BHA rotating around another point than its geometric centre characterizes BHA whirl. If the BHA moves freely around the wellbore while rotating this will severely impact the wellbore and the components in the assembly. BHA whirl may induce both forward and backward whirl and is a complex vibration state, leading to lateral displacements and friction against the wellbore wall. It is typically initiated by friction-driven gearing of stabilizers, mass imbalance of the BHA or by lateral vibrations caused by resonance. Vertical wells and over gauge holes also seem to amplify the tendency of BHA whirl [6].

BHA whirl leads to critical vibration levels and is the main cause of BHA and downhole tool failure. The repeated flexing of the drill collars increase the fatigue rates of these components and the high bending stresses lead to damaged drill collar connections and downhole electronic failure [6].

Forward whirl

Forward whirl is seen when centrifugally induced bending of the drillstring occurs, as a result of imbalance in the assembly [5]. As shown in figure 6, the centre of rotation moves in the same direction and at the same rate as the drillstring (clockwise) and thereby maintains the same contact point with the borehole wall. The phenomenon results in one-sided wear on components, seen as flat spots on one side of the collar.

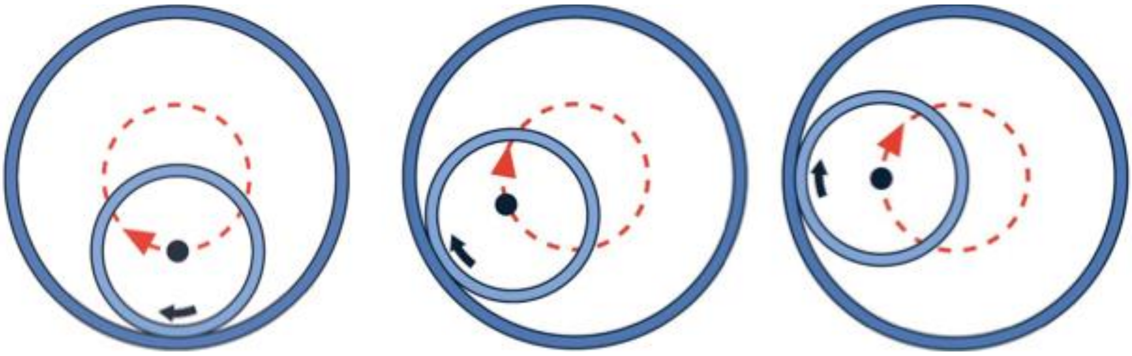

Figure 6: Forward whirl

Transition from forward to backward whirl can occur if the rotary speed is increased sufficiently. The energy of the collision between the drillstring and the borehole wall becomes significant and the transition is initiated. In addition, the formation hardness can speed up the transition to backward whirl, as harder formation tends to generate higher shocks [9].

Backward whirl

Backward whirl is the most feared vibration motion, as it creates large bending moment, resulting in high rate of component fatigue. As seen from figure 7, the centre of rotation moves in opposite direction to the rotation of the drillstring (counter clockwise progression).

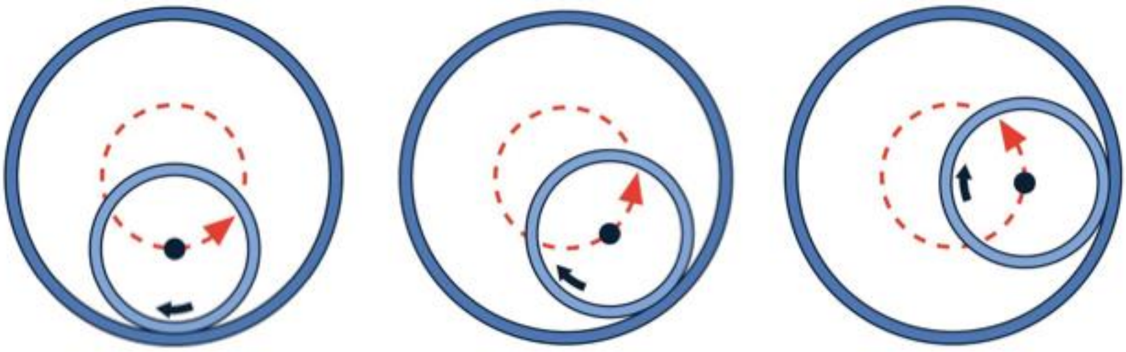

Figure 7: Backward whirl

Backward whirl can be detected by monitoring the torque values, as the surface torque increases when the downhole vibrations are at its worst. The drillstring deflection is also connected to the rotary speed, at increasing rotary speed the deflection increases [9].

A summarization of the main features of the different vibration modes is given in table 1.

Table 1: The main features of the different vibration modes

	Axial	Torsional	Lateral
Mode of vibration:	Bit bounce	Stick-slip	Whirl
Motion:	Up/down movement along drillstring axis	Twisting about the drillstring axis	Bending or whirl, transverse to the drillstring axis
Main cause:	Hard formation Vertical hole RC bits	Aggressive PDC bits Friction between wellbore and BHA High-angle wells	Aggressive side cutting bits Friction Washed out hole Unstable BHA/unstabilized drillstring
Frequency [1]:	1 - 10 Hz	<1 Hz	Bit whirl: 5 - 100 Hz BHA whirl: 5 - 20 Hz
Symptoms seen at surface:	Large WOB fluctuations Rig/top drive shaking Reduced ROP	Top drive stalling Torque and RPM fluctuations Reduced ROP	Increased surface torque Reduced ROP
Post-drilling evidence:	Early bearing failure Broken cutters BHA failure	Damaged cutters Over torqued connections Twist-offs BHA failure	Damaged cutters and/or stabilizers Overgauge holes BHA failure Washouts One-sided wear on BHA components
Real-time mitigation actions:	Increase WOB and decrease RPM	Decrease WOB and increase RPM	Increase WOB and decrease RPM

2.1.4 Modal coupling

Axial, torsional and lateral vibrations are not independent of each other and thus combinations can occur if the modes trigger one another. Vibrations occur in axial, torsional and/or lateral directions simultaneously and this phenomenon is defined as modal coupling. Modal coupling is usually a result of lack of control of one of the vibration modes, allowing it to become sufficiently severe and thereby commence one or several of the other modes.

The coupling between the different modes is dependent on the dynamic motion of the drillstring. Transverse vibrations cause the drillstring to buckle. When the drillstring buckles it will become shorter in the length direction, initiating up and down movement in form of axial vibrations. The coupling between axial and transverse vibrations is strong, as coupling is correlated to the shortening of the drillstring. Torsional vibrations, on the other hand, will not result in the same degree of shortening of the drillstring in axial direction, due to the different vibration motion. Twisting motion will initiate less up and down movement compared to the side-to-side motion seen when lateral vibrations are present. The coupling between axial and torsional vibrations is consequently less pronounced [10].

Example 2: Coupling between axial- and torsional vibrations

Torsional vibrations will cause a twisting stress (shear stress) and a rotation (shear strain). When a solid rod is subjected to torsion stress, an axial shortening will occur if a lateral contraction property exists in the material (e.g. steel pipes), see figure 8. The axial deformation caused by torsion can be calculated [11]:

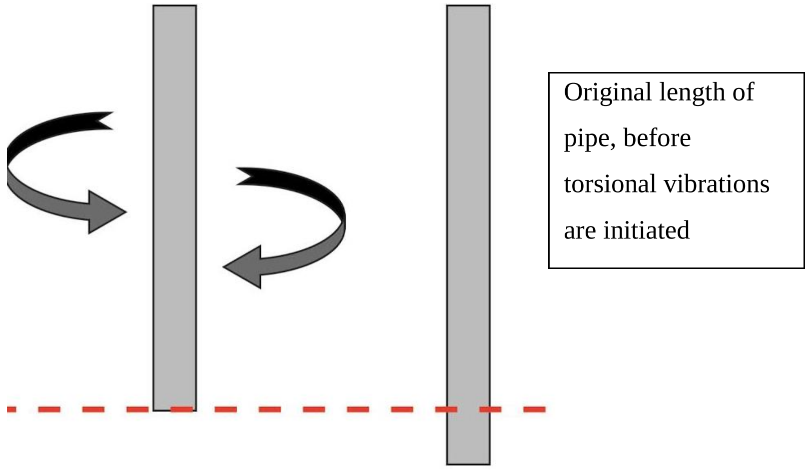

Figure 8: Coupling between torsional- and axial vibrations

If the torque, stiffness and cross sectional area are assumed to be constant, the total twist is given by:

$$\Theta = \frac{T l_o}{G J_T} \quad \text{(Eq.9)}$$

The length of the fibre is equal to the original length:

$$l_o = \int_0^{\Theta} \sqrt{R^2 + {h_p}^2} d\theta = \Theta \sqrt{R^2 + {h_p}^2} \quad \text{(Eq.10)}$$

$$h_p = \frac{l_f}{\Theta} \quad \text{(Eq.11)}$$

$$l_o = \Theta \sqrt{R^2 + (\frac{l_f}{\Theta})^2}$$

The length of the outer fibre, as it twists around along the final length of the rod becomes:

$$l_f = \sqrt{{l_o}^2 - R^2\Theta^2} \quad \text{(Eq.12)}$$

Numerical example:

Assume that the BHA is 100m (328ft) long and has a radius of 0,2m (8” collar). If the BHA is subjected to 1 revolution, and the radius of the collar is assumed to be compact (neglecting the inner diameter), the length will become:

$$l_f = \sqrt{100^2 - 0{,}2^2(2\pi)^2} = 99{,}9921m\ (327{,}975ft)$$

The shortening of the BHA will consequently be:

$$l_o - l_f = (100 - 99{,}9921)m = 0{,}007896m = \mathbf{7{,}9mm\ (0{,}025ft)}$$

Example 3: Coupling between axial and transverse vibrations

Assume that a string exposed to lateral vibrations becomes wavy, as illustrated in figure 9. As mentioned, the string will become shorter in the axial direction.

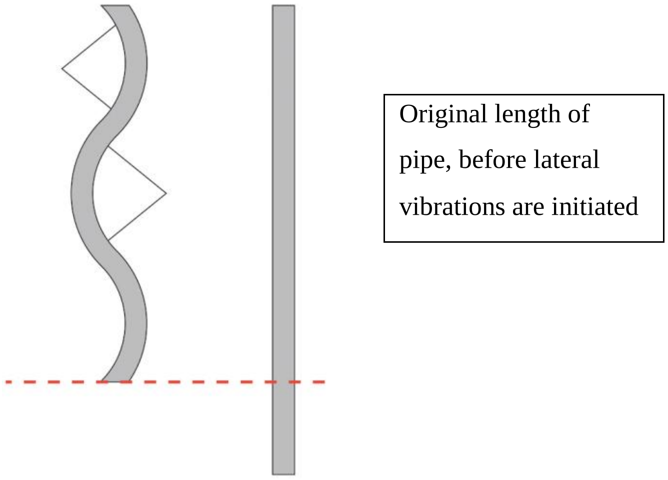

Figure 9: Coupling between lateral- and axial vibrations

Each wave can be illustrated as a circle segment (figure 10).

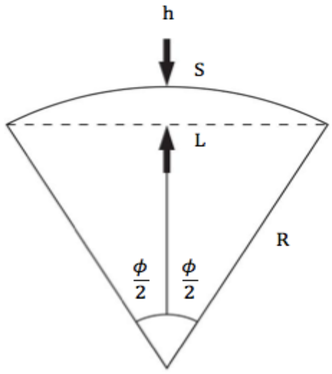

Figure 10: Circle segment

The original length is s, and the new height is defined as L. That gives us the following equations [12]:

$$s = R\phi \quad \text{(Eq.13)}$$

$$sin\frac{\phi}{2} = \frac{L/2}{R} \rightarrow L = 2R\sin\left(\frac{\phi}{2}\right) \quad \text{(Eq.14)}$$

The equation for the shortening of the string becomes:

$$\Delta l = s - L = R\left(\phi - 2\sin\left(\frac{\phi}{2}\right)\right) \quad \text{(Eq.15)}$$

The lateral displacement is given by:

$$h = R - R\cos\left(\frac{\phi}{2}\right) = R\left(1 - \cos\left(\frac{\phi}{2}\right)\right) \quad \text{(Eq.16)}$$

R can be eliminated:

$$R = \frac{\Delta l}{\phi - 2\sin\left(\frac{\phi}{2}\right)} = \frac{h}{1 - \cos\left(\frac{\phi}{2}\right)}$$

$$\Delta l = h\frac{\phi - 2\sin\left(\frac{\phi}{2}\right)}{1 - \cos\left(\frac{\phi}{2}\right)}$$

Using Eqs. (13) and (16), ϕ can be found:

$$R = \frac{s}{\phi} = \frac{h}{1-\cos\left(\frac{\phi}{2}\right)} \rightarrow \frac{s}{h} = \frac{\phi}{1-\cos\left(\frac{\phi}{2}\right)} \quad \text{(Eq.17)}$$

$$\phi = \left(1 - \cos\left(\frac{\phi}{2}\right)\right) \times \frac{s}{h} \quad \text{(Eq.18)}$$

Numerical example:

Now, assume that s is 10m (32,8ft) and h is 0,1m (0,328ft). ϕ can be found by adjusting ϕ until the left side and wright side in Eq. (17) is equal. When inserting the numbers into Eq. (17), we get:

$$\frac{10}{0,1} = \frac{0,08}{1 - \cos\left(\frac{0,08}{2}\right)} \rightarrow 100 = 100$$

Meaning that for s=10m and h=0,1m, $\phi = 0,08$. Based on this, the other equations can be calculated:

$$R = \frac{10}{0,08} = 125\, m\ (410ft)$$

$$L = 2 \times 125\sin(0,5 \times 0,08) = 9,997m\ (32.791ft)$$

$$\Delta L = 10 - 9,997 = 0,003m\ (0,009ft)$$

Assuming we have 10 waves on a 100m long string, the total shortening becomes:

$$10 \times 0,003 = 0,03m = \mathbf{3cm}\ (\mathbf{0,09ft})$$

Table 2: Coupling between axial and transverse vibrations

h (m)	s (m)	Number of waves	$\phi\ (rad)$	R (m)	L (m)	$\Delta L\ (m)$	Total shortening (cm)
12 ¼" (0,3m) hole and 8 " (0,2m) drill collar h= 0,1m	10	10	0,08	125	9,997	0,003	3
	10	20	0,08	125	9,997	0,003	6
12 ¼" (0,3m) hole and 10 " (0,25m) drill collar h= 0,05m	10	10	0,04	250	9,999	0,001	1

Table 2 illustrates that the shortening becomes larger with a smaller drill collar diameter. A smaller drill collar diameter in relation to the hole diameter means that there is larger clearance between the collar and the wellbore wall and hence the collar has larger room for lateral displacement.

Examples 2 and 3, verifies that the coupling between axial and lateral vibrations leads to a larger shortening of the drillstring compared to the coupling between axial and torsional vibrations. Consequently, the coupling between axial and lateral vibrations is stronger [12].

2.2 Sources initiating and/or amplifying drillstring vibrations

Drillstring vibrations are mainly caused by the bit and drillstring interactions with the formation under specific drilling conditions. Sources can excite downhole vibrations directly, trigger other vibration mechanisms or induce resonance into the drillstring. Resonance is generated if the excitation source frequency is close to the natural frequency of the drillstring (axial, torsional or lateral). An amplification of the vibration amplitude is seen. The speeds at which resonant conditions occur are defined as critical speeds. Normally, vibrations are highest at resonance, but if a high level of excitation is present, a significant level of vibration may exist in the drillstring, independent of resonance. Large-amplitude vibrations during drilling will lead to accelerated drillstring fatigue [1].

In order to introduce proper vibration mitigation actions, knowledge of their origin and excitation mechanisms are highly important. In this section, the most important driving forces behind downhole vibrations will be described.

2.2.1 Mass imbalance

The drillstring is made up of several components, and each component is to some extent unbalanced. Sources of mass imbalance include; borehole misalignment, initial bending and curvature, and wear during the operation. A rotating drillstring is characterized as unbalanced when the centre of gravity does not coincide with the axis of rotation. Centrifugal forces are generated when the unbalanced drillstring is rotated, leading to noticeable levels of vibration. The imbalance force acts on the centre of gravity causing the drillstring (shaft) to bend out or whirl, illustrated in figure 11. Shocks are first seen when the rotary speed corresponds with the natural frequency of the unbalanced drillstring, and the string impacts the wellbore wall. Mass imbalance of drillstring components is identified as a significant source of lateral vibrations in the drillstring, potentially leading to backward whirl. Although it is evident that mass imbalance is a source of vibrations, it is often assumed that the bit is the main generating source [9].

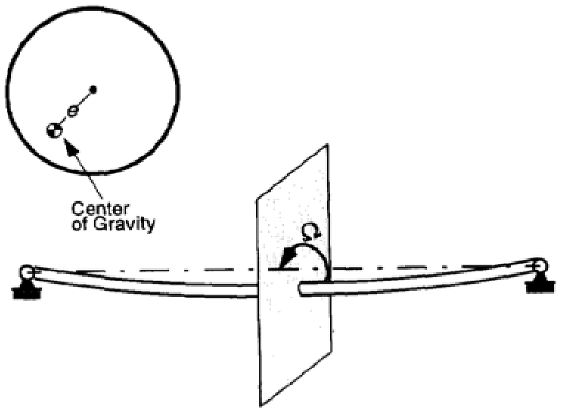

Figure 11: Imbalance force acts on rotating shaft causing it to bow [9]

2.2.2 Hole angle and hole size

Detrimental drillstring vibrations are being recorded in both vertical and horizontal wells. However, BHA component failure is more likely to occur in vertical holes, as vertical and near vertical wells increase the likelihood of experiencing severe axial and lateral vibrations. The string is more prabable to buckle sinusoidally or helically and thus the likelihood of cycling bending increases as the string is rotated. The WOB in vertical wells will have a larger influence and bit bounce may become a problem. In directional and highly deviated wells, gravity tends to reduce the potential of sideways motion of the rotating assembly, as it is pushed towards the low side of the wellbore. The side forces on the BHA are more pronounced. If the well inclination increases above 15 degrees, the string at the BHA is less likely to helically buckle, due to the increase in normal force that must be overcome. However, the drillstring may still sinusoidally buckle along the low side of the wellbore, generating lateral vibrations as it is rotated. Torsional vibrations on the other hand, are more probable to occur in deviated holes, being excited by the frictional torque. Higher frictional torque between the drillstring and the wellbore will leads to a reduced amount of energy reaching the bit. Consequently, the BHA, drillstring and bit are subjected to more torsional vibrations. The wellbore tortuosity can also affect the level of torsional vibrations, as large dogleg severity (DLS) and sharp changes in hole angle tend to generate more frictional torque [6].

The borehole size relative to the outer diameter (OD) of the BHA determines the amount of deflection the tools undergo when vibration is generated. Over gauge holes enables side-to-side movement and buckling. The bit/BHA "walks" around the hole freely, touching the wellbore wall and thereby generates whirl and transverse vibrations. The drillstring lacks sufficient stabilization [6]. In contrast, undergauge sections may amplify the stick-slip tendencies, due to increased torque and friction factor.

2.2.3 Drilling parameters (RPM, WOB and mud lubricity)

As illustrated in example 1, the drilling parameters influence the severity of downhole vibrations and by alternating the parameters the vibration level is better controlled. A frequent problem is to know which parameters that should be manipulated without negatively impacting the drilling performance. Vibration control can be performed during drilling by manipulating the RPM, WOB, flowrate and mud lubricity. These parameters are the only means that can be changed by the driller, while drilling, to manage vibrations at an early stage.

Increased vibration levels with increasing RPM have been confirmed by several studies and papers. As vibrations are a function of RPM and WOB, wrong combination will lead to high vibration tendencies. Defining a perfect range for these drilling parameters is essential in order to reduce the level of vibration and improve the drilling performance. The optimum range of drilling parameters will vary according to vibration modes, well conditions and BHA design, among other variables. Defining this range can be done in the pre-drilling phase by using BHA design optimization software or during drilling by monitoring real-time data.

When stick-slip is generated, due to the BHA rubbing against the wellbore wall, the mud lubricity can be increased to reduce the friction at the bit and BHA. The same concept can be applied when BHA whirl is present [1]. Oil based mud may be preferred as it has greater lubricity than water based mud and hence can serve to supress stick-slip. If water based fluids are used, lubricants could be added, to reduce the friction. The mud lubricity properties are frequently altered to obtain vibration resistant conditions.

2.2.4 Bit selection

The bit-formation interaction is most often characterized as an axial excitation mechanism. Each bit creates a unique cutting pattern in the underlying formation below the bit that continues to propagate as it turns at the rock face. Disruption in this pattern forces the cutting element to jump over the cutter made ridges and differential loading is experienced, as some cutters bite while others are free. This could potentially lead to bit bounce [6].

Drilling efficiency and vibration generation is dependent on choosing the correct bit for the formation to be drilled. Bit induced vibrations are generated when the bit design and functionality are inadequate for the specific operation. PDC bits normally generate higher level of torsional vibrations, due to their high friction, while RC bits increases the likelihood of experiencing axial vibrations. Aggressive features such as large cutters, lower number of cutters and high angles on cutters relative to the formation (back-rake) will also amplify the vibration indices [6]. The bit should therefore be preselected based on formation type. In addition the depth of cut (DOC) and angle of cutters relative to the formation must be predefined and optimized. It is highly important to operate within the recommended parameters of the bit to avoid dynamic instability.

2.2.5 Formation type

In conventional drilling it is essential to know what type of formation that is being drilled. The cementation material will determine the hardness or the strength of the rock. Vibrations are affected by the hardness of the formation and increasing formation strength is normally associated with increased vibration level [6]. However, it is important to keep in mind that also soft formations can lead to high vibration levels. Washouts and unstable formations enable the drillstring to move sideways more freely, increasing the likelihood of experiencing lateral vibrations and whirl.

The formation layering and interaction with the bit can affect the propensity to experience drillstring vibrations. Differential hardness of rocks, such as interbedded sands and clays or limestone stringers, creates uneven drilling and acts as a source of vibration. Severe shock and vibration are associated with interbedded formations that have sections with high-compressive strength and low-compressive strength, due to varying drillability [6]. This problem is particularly pronounced in underreamer operations.

2.2.6 BHA design

Poor pre-planning of the BHA design and configuration can lead to severe shock and vibration. Critical components such as bit, reamers and stabilizers must be reviewed in terms of functionality and interaction with the surroundings, to provide a vibration limiting BHA. Placement of these components and small changes made to the design can lead to large enhancements, in terms of lower vibration level and improved cost effectiveness. In addition, various tools can be added to the assembly to prevent severe vibrations from occurring. These factors are more thoroughly analysed in chapters 4 and 5.

2.3 Consequences of drillstring vibrations

Drillstring vibrations have several damaging consequences contributing to poor drilling performance, which leads to non-productive time (NPT) and additional expenditure. In this section the most visible consequences caused by drillstring vibrations are described.

2.3.1 Wellbore instability

Wellbore instability issues have in the past mainly been associated with the chemical interaction between drilling fluid and formation, and the main objective when studying drillstring vibrations has for a long time been solely to reduce drillstring fatigue problems. The impact downhole vibrations may have on wellbore stability has therefore received insufficient attention. Identifying the correct cause of wellbore instability is crucial, to avoid a delay on the problem correction and for the operation to be economically efficient

It should be known that drillstring vibrations could lead to irreparable damage to the borehole, when having sufficient lateral amplitude to hit the wall. Vibrations can lead to large fractured areas, resulting in rock blocks falling into the well. In severe cases vibrations can lead to instability problems, out of gauge holes, time losses and hence anti-economical operations. When drilling through hard formations, the chemical interaction between the drilling fluid and the rock should be excluded as a cause of wellbore instability. In these situations, drillstring vibrations may have a significant impact and should be studied thoroughly as a potential cause [13].

It is natural to emphasise lateral vibrations when discussing wellbore problems. When the drillstring hits the wellbore wall, enlargements will be created and the measurement while drilling (MWD) equipment may be destroyed. Vibrations are measured as accelerations, with sensors placed in a sub near the bit. Accelerations are measured in g´s, where 1g is the earth´s gravitational acceleration. The lateral accelerations can reach 80g´s in harsh environments and in severe cases 200g´s has been recorded. In an operation experiencing 80g`s, using a drill collar with 223kg/m (150lb/ft) of mass, the lateral force exerted by 0.3048m (1ft) of drill collar will be 5.41 tons (11927lb). 5 tons acting on the formation will naturally cause significant damage to the wellbore wall. When lateral vibrations are present, the drillstring will hit the wellbore wall repeatedly, impacting the wall multiple times. The number of times the drillstring hits the borehole, as well as the magnitude of the impact force will affect the wellbore stability and downhole conditions [13].

Lateral vibrations can evidently be a source of hole enlargement and instability issues, affecting the hole quality. The importance of vibration analysis in regards to instability issues should be stressed.

2.3.2 Damaged downhole components

Frequently detrimental drillstring vibrations can cause both minor and catastrophic failure in all components included in the BHA.

The most obvious consequences of drillstring vibrations on downhole tools are [6]:

- Bit and reamer damage, reducing the ROP and increasing bit/reamer costs
- Motor and rotary steerable damage, causing unplanned trips
- Accelerated fatigue of all drillstring components, consequently leading to twist-offs and potentially fishing trips. In worst case, unplanned sidetracks around stuck assemblies
- Destruction of downhole electronics, causing failure of tools and additional trips
- Interference with downhole tool telemetry, causing gaps in data
- Damaged rig equipment, causing NPT and increased costs

2.3.3 Increased costs

The financial losses sustained from drilling dynamics are significant and have been estimated to be 5-10% of the total drilling costs [1]. As the petroleum industry is driven by maximizing profit and minimizing costs the economical aspect of detrimental drillstring vibrations is particularly important. As mentioned, equipment failure and damaged downhole tools are often attributed to drillstring vibrations. These consequences will lead to reduced equipment efficiency, increased maintenance costs, additional trips and fishing operations, influencing the time and the cost of the well. This is neither feasible to the operator nor the directional supplier. Ineffective drilling in terms of wasted energy, decreased ROP and NPT can be avoided by being proactive in the vibration mitigation process.

3. Standards and measurement techniques

3.1 Standardization

There is a great need for an effective approach to handle the challenges caused by vibrations. As to date, there is no standard present on how to handle and measure vibrations. Each directional supplier have their own internal procedures, making it more challenging for the operator to control whether or not vibrations are given sufficient attention. Prevention actions must be given adequate attention in the pre-drilling phase and evaluated sufficiently after ended operation. To perform proper mitigation, an extensive process of planning, conducting and evaluating is needed. Statoil should therefore implement a standard procedure that all suppliers have to follow, containing minimum requirements on how to handle vibrations during all phases of an operation. By doing this one can ensure that detrimental vibrations are given sufficient attention. In addition, an industry standard on how to measure and classify vibrations should be developed, either through collaboration between the operators and the suppliers or by an organization such as the Society of Petroleum Engineers (SPE). Through standard guidelines on how to measure, handle and mitigate drillstring vibrations, drilling operations can be significantly improved, potentially saving several millions each year, by reducing the failure occurrence and streamlining the operations.

The current lack of a standard of vibration measurements leads to challenges for both the operator and the suppliers. The operator experiences difficulties in comparing the economic payoffs and the quality of the service offered by the different suppliers. It becomes challenging to correlate and quality check vibration data, to identify the best possible approach and to learn from previous experiences.

A standard is highly dependent on proper training and communication of key personnel to be efficient. All personnel must be familiar with the different modes of vibrations and should be able to recognize possible causes. Standard guidelines should exist to prevent these causes, and effective mitigation procedures should be established. Acceptable level of vibrations and justifiable drilling parameters must be identified for the specific operation, and every worker involved should be familiar with them. When these levels are exceeded, or if damage is seen, all involved in the operation should be notified, in order to implement correct counteractive measures. A standard should include guidelines on when the operator and other personnel should be notified. To establish good communication between the operator and suppliers, relevant information should be made available. Logs, information on runs with high level of vibration, information on successful runs, mitigation procedures and failure reports should be easily accessible for all involved.

3.1.1 Suggestion to vibration mitigation workflow

In the pre-drilling phase, expected vibration level should be identified, and a suitable BHA configuration and drilling parameters must be selected. In this phase, key personnel should be informed on possible vibration challenges met during the operation. All personnel should be familiar with what types of vibration that might occur, where they are expected to occur and the mitigation actions implemented. The BHA configuration should be analysed in the BHA design optimization software each supplier uses, to establish the preferred setup. Alternative BHA configurations and drilling parameters can then be considered. All components possibly inducing vibrations should be evaluated, and the bit type and stabilization elements should be monitored closely. In addition, performance on offset wells should be analysed for more accurate predictions. Special attention should be given to the placement of stabilizers and the interaction between the bit and the reamer, in underreamer operations. It is highly important to spend time on evaluating the vibration patterns in the pre-drilling phase, to avoid additional costs at a later stage. The petroleum industry has a huge potential for improvement in this area.

During drilling, surface data and real-time MWD data must be monitored continuously, to identify the vibration level. The recordings should be thoroughly analysed and recommendations should be made. If high levels of vibration are recorded, key personnel should be informed immediately and counteractive measures must be performed. Drilling parameters, such as RPM, WOB and flow rate must be manipulated during the operation to reduce the level of detrimental vibrations. In the conduction phase it is highly important to address problems immediately, in order to limit the damage as early as possible.

In the post-drilling phase huge advancements can be made. Not only failure runs should be evaluated, but also successful runs, to establish good operational procedures for future use. All BHA components should be reviewed after the run, in order to detect damage caused by vibrations. Experiences gained during the run should be evaluated and reported, in order for future operations to run smoothly. The results should be compared to the findings in the pre-drilling phase. Before continuing drilling, possible BHA design changes and drilling parameter adjustments must be established. The petroleum industry can make vast business improvements in the evaluation phase after ended operation. A summarization of the most important tasks in each phase of the operation is given in table 3.

Table 3: Work flow for vibration mitigation

Pre-drilling	•Planning •Analyze offset wells •Identify risks •Advanced BHA modelling (design out vibrations) •Establish mitigation actions
Drilling	•Interpret real-time data •Adjust parameters •Perform mitigation actions if necessary •Monitor
Post-drilling	•Post run evaluation •Capture lessons learned for both succesful runs and failure runs

3.2 Different measurement approaches

The main content of this section is taken from [2].

Downhole vibration measurements were first introduced to the oil industry in the early 1990s and have in recent years proven to be vital to improve the drilling efficiency and reduce operational costs, all over the world. Today the use of vibration measurement tools has become a standard procedure and most operators have integrated vibration sensors run together with the MWD and logging while drilling (LWD) applications. Real-time data enables the operator to monitor the criticality of the vibrations experienced downhole and to manipulate the drilling parameters. The objective is to reduce the vibrations and increase the life of the BHA components. It is highly important that the tools are not operated under high severity levels of vibration.

For most formation data acquisition, standards are present to make it easy to compare and optimize the operation. Although drillstring vibrations have received increased focus in recent years, there is still no industry standard on how to sample, process and present downhole vibration data. The service companies measures the same parameters, but has their own way of performing the measurements, interpreting the results and their own severity ranking. Schlumberger, Halliburton and Baker Hughes all define the operational limits of the equipment by grouping the measured accelerations. The vibrations are most often measured by an accelerometer mounted in the MWD [2]. The acceleration values are given in gravity, where 1g equals $9{,}81 m/s^2$, which is the acceleration of gravity at sealevel.

3.2.1 Baker Hughes

Baker Hughes bases their system on the root mean square (RMS) values from the instantaneous accelerations. Eight vibration severity levels are defined (numbered 0-7), for axial and transverse vibrations (table 4 and 5). Baker Hughes does not use peak values and these are apparently not even recorded.

Table 4: Baker Hughes, severity table for lateral vibrations [2]

Lateral RMS values	Severity
Repeated lateral RMS values from 3 to 5g	Rapid accumulation of wear. Should not occur for more than 3 hours
>5g	Almost guaranteed failure. Should not occur for more than 20 minutes

Table 5: Baker Hughes, severity table for axial vibrations [2]

Axial RMS values	Severity
3 to 5g	Critical, but rare. Should not occur for more than 3 hours
>5g	Critical, but rare. Should not occur for more than 20 minutes

Baker Hughes treats torsional vibrations as a part of the more general stick-slip problem.

3.2.2 Halliburton

Halliburton separates the measured accelerations into three severity levels; low (green), medium (amber) and high (red). Both average and peak values are used to classify the severity of the vibrations. The average values are calculated over a period of 4 seconds and are both dependent on the size of the accelerations and the time span. The peak level is defined as the highest instantaneous acceleration in an interval of 4 seconds, and is categorized after size and frequency of occurrence. The definition of each level varies for different tool types and is quite complex. Typical values are shown in tables 6 and 7.

Table 6: Halliburton, severity table for lateral and axial vibrations (average values) [2]

Vibration mode	Average acceleration	Severity
Lateral	>4-6g	Red zone, should not occur for more than 18 minutes
Axial	4g	Red zone, should not occur for more than 8 minutes

Table 7: Halliburton, severity table for lateral and axial vibrations (peak values) [2]

Vibration mode	Peak values and events	Severity
Lateral	More than 150 events >90g	Critical
Axial	More than 100 events >20-40g	Critical

The criticality limits defined, based on average values, are relatively similar for Baker Hughes and Halliburton.

3.2.3 Schlumberger

Schlumberger uses a different quantification system than Baker Hughes and Halliburton. A threshold is defined, usually 50g´s, and number of events where the acceleration exceeds this value is counted (table 8). Shocks below these levels are viewed as non-damaging. The shock risk is separated into 4-risk levels (0-3).

Table 8: Schlumberger, severity table for axial and lateral vibrations [2]

Number of events	Severity
Less than 50 000 events, >50g	Level 0, no risk of tool failure
Cumulative total of more than 200 000 events, >50g	Level 3 (red), high risk of tool failure

As seen from the table above the same classification system is applicable for both axial and lateral vibrations. Torsional vibrations have a different classification system and are measured separately.

The approaches used vary between the three directional drilling suppliers and thus makes it challenging to compare and correlate the data material. Baker Hughes and Halliburton have some similarities as both uses the average values. Schlumberger on the other hand cannot be directly compared with the other two, as only the strongest shocks are taken into consideration. Different outcomes in terms of defined criticality and actions taken can occur based on the supplier the operator is using. The need for an industry standard is yet again stressed.

4. Tools and techniques to minimize shock and vibration

Today, service companies have confidence in the design and functionality of the BHA. However, vibration-related BHA failures are still common and poor BHA design has been recognized as a contributor to severe drillstring vibrations. An optimum BHA design should be selected based on the particular task at hand, by analysing tools, components, dimensions and configuration.

In this chapter, the most effective tools and techniques for vibration mitigation are evaluated. The objective is to shed light on good operational practices and to analyse different alternatives that can lower the frequency of detrimental vibrations in the future. Some of these considerations should be implemented in all operations, such as proper stabilization, while tools such as roller reamers, AST and Frank`s HI tool, have different application areas and should only be considered if the circumstances call for it. Field experiences are presented and analysed to illustrate the effect of the tools and techniques on the vibration level. The aspects discussed should be kept in mind when designing the BHA, as they can prove beneficial in minimizing shock and vibration, and hence improve the drilling performance.

4.1 Placement and span length between stabilizers

Stabilizer placement is highly important to avoid drillstring vibrations and to secure safe drilling. When placing a stabilizer, a centralized location with minimal lateral displacement should be chosen, to minimize stress at the contact points. Tools, such as measuring devices, have pre-defined placement and should be positioned first. When these components have been placed within the assembly, stabilization placement should be evaluated. The stabilizers should be positioned at the optimum stabilization contact location. Best practice is normally to place a stabilizer near the bit, as close spacing of the first support will provide lower vibration levels. Ideally, the stabilizers should be relocatable, to be able to adjust the stabilizer spacing and hence deliver the BHA with lowest possible vibration indices. Development of relocatable stabilizers should be made a priority to achieve optimum dynamic performance objectives [14].

The span length between stabilizers is a factor of relevance. Increased length between stabilizers or other contact points often result in lateral vibrations, as the drillstring can move sideways more freely. A maximum span length should be established to avoid lateral bending of unsupported sections. The amount of stabilizers will also affect the propensity of experiencing vibrations, and lack of stabilization in slick and pendulum assemblies often leads to whirling. A packed BHA, with several stabilizers, provide more stable drilling than a slick BHA, without stabilizers, as an unbalanced assembly has fewer restrictions. A stiffer drillstring will be able to withstand vibrations to a larger extent. However, it should be kept in mind that multiple stabilizers may put constraints on the directional objectives, due to decreased flexibility. In addition, more torque can be generated at the contact points and hence torsional vibration and stick-slip may become a problem. In such cases roller reamers can come to good use (described in section 4.4).

Whenever possible, the number of undergauge stabilizers should be minimized, as they enable detrimental contact with the borehole wall if a small displacement is initiated.

4.2 Flex stabilizers

Some stabilizer types can potentially increase the risk of experiencing severe shock and vibrations. Flex stabilizers are most often placed above the rotary steerable tools to facilitate rotary steerable directional objectives. Flex stabilizers normally comprises a stabilizer with a smaller diameter connecting flex sub. This component can increase the lateral vibration level, as it increases the flexibility due to reduced OD. Compensating design changes should be made to the BHA if a flex sub is needed for directional objectives. Such measures could be to reduce the span length between the stabilizers or place the flex stabilizer closer to the bit, to offset the increased flexibility. Alternatively, if a flex stabilizer can be avoided, one should consider replacing it with a standard non-flex stabilizer, to make the BHA stiffer and thereby reduce the risk of experiencing detrimental vibrations [14].

4.2.1 Field validation

<u>Flex stabilizer vs. standard non-flex stabilizer</u>

The drilling results for two 17 ½" BHA runs were compared by [14], to demonstrate how flex stabilizers affect the vibration level and how redesign of the BHA can improve the drilling performance. The two assemblies shown in figure 12 were identical, except BHA-1A had a flex stabilizer above the rotary steerable system (RSS), 4.6m (15ft) from the bit, whereas BHA-1B had a standard non-flex stabilizer. The bits for the two runs were identical and both were new. The assemblies were run in close offset wells with similar formations and at similar depths, to verify the adverse effect flex stabilizers can have on the vibration level.

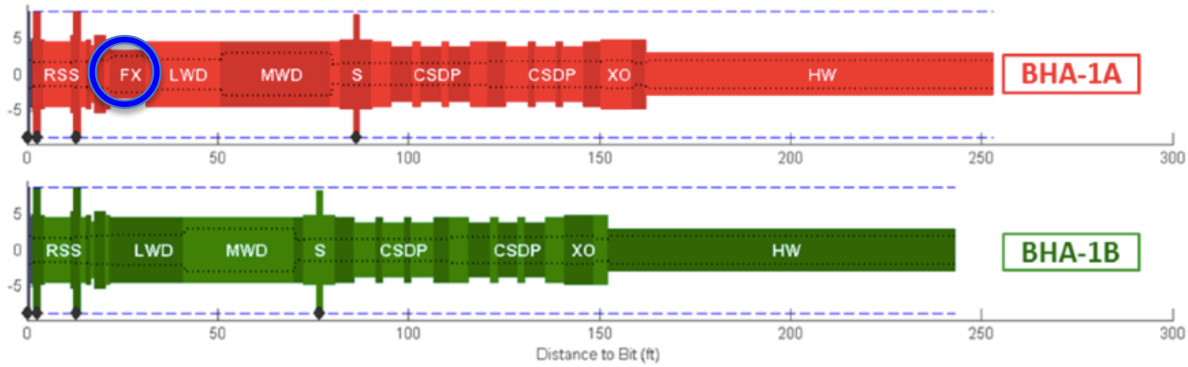

Figure 12: BHA configuration with and without a flex sub [14]

For comparison, the lateral vibrations for both assemblies were measured in gravity units, g. Figure 13, displays the lateral vibration data distribution for the two BHAs, by RPM and vibration level bins. It is evident that BHA-1A (with flex stabilizer) generates significantly higher lateral vibration level compared to BHA-1B. The average lateral vibration level was 1.8g for BHA-1A, in contrast to 0.6g for BHA-1B. Meaning that at 160RPM, the lateral vibration level was three times higher for the BHA including a flex stabilizer. This comparison indicates a loss of lateral stability when implementing flex stabilizers and shows how redesign of the BHA can contribute to minimize shock and vibrations. Since low vibration indices are preferred, BHA-1B would be recommended over BHA-1A [14].

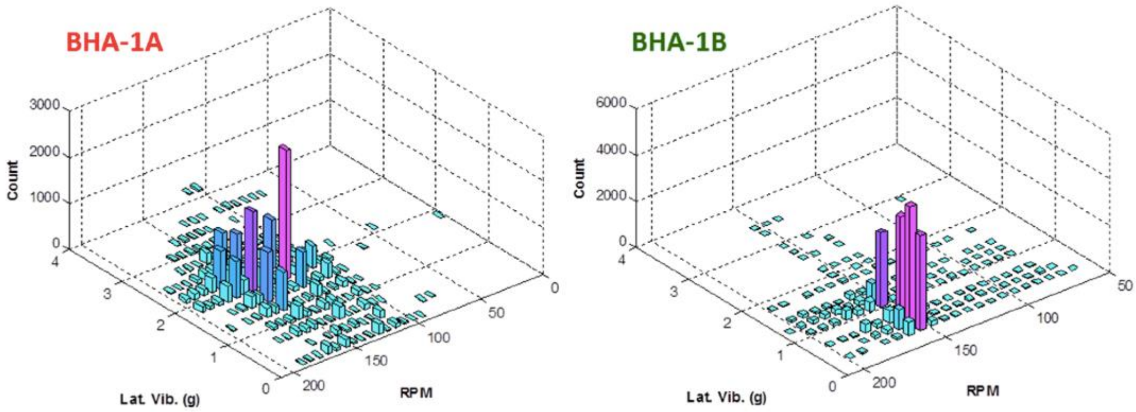

Figure 13: Lateral vibration distribution for BHAs with and without flex stabilizer [14]

Two disparities led to increased lateral vibrations in the run with flex stabilizer (BHA-1A) [14]:

1. The flex sub increased the span length between the RSS stabilizer and the string stabilizer above the MWD
2. The flex stabilizer increased the span flexibility due to reduced OD

Statoil experience with flex stabilizer on Grane

A comparative field experience on the Statoil operated Grane field also illustrates the advantages of replacing a flex stabilizer with a modular stabilizer. In the first run with a 16x17 ½" BHA, Statoil incorporated a flex stabilizer in the assembly and high level of vibration was recorded. In the second run, using a 17 ½" BHA, the flex stabilizer was replaced by a modular stabilizer with larger diameter. Subsequently, lower level of vibrations was recorded, indicating that modular stabilizers are less prone to vibrations, as they make the BHA stiffer [15]. It is important to mention that the removal of the underreamer could also have affected the results. Nevertheless, it was concluded that the replacement of the flex stabilizer with a modular stabilizer could contribute to reduce the vibration indices. This finding should be taken into consideration when designing the BHA, both in underreamer operations and in operations without underreamers.

4.3 Sharp edges on bit, underreamer and stabilizers

Improper design of some specific downhole components can lead to severe vibration levels. Sharp edges on downhole tools have the ability to cut or initiate pivot points at the borehole wall, when off-centre movements of the bit and/or BHA are present. The interaction between the sharp edges and the borehole wall generates torque-, WOB- and RPM fluctuations regardless of vibration mode. When off-centre movements are initiated, sharp edges in the direction of the movement will initiate cutting, as they come in contact with the borehole. The aggressiveness of the edge will to a large extent determine the degree of cut into the borehole and consequently the level of torque-, WOB- and RPM fluctuations. For example, large bits with big moment-arms tend to generate intense fluctuations [16].

How the sharp edges affect the severity of the vibrations is also dependent on the stability of the drilling system. A stable drilling system will not tend to oversize the borehole significantly and thus lower torque-, WOB- and RPM fluctuations are introduced [16].

Bit, stabilizers and reamers are the downhole components with highest risk of having damaging edge geometry. Figure 14 shows how the edge geometry on these components should be modified. By bevelling the edges on bit, stabilizers an underreamers shock and vibration can be minimized.

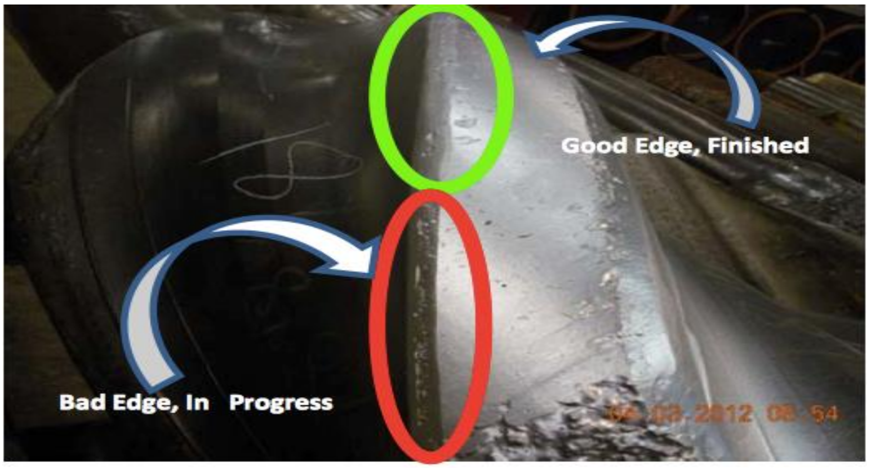

Figure 14: Edge Modifications [16]

4.3.1 Example – gage pad with cutting tendencies

A gage pad with peculiar dull conditions has been described in previous written literature and serves to illustrate how sharp edges on BHA components can initiate cutting. The gage on a bit was inspected after use and the conditions of the pad indicated that it had cutting tendencies. As shown in figure 15, the pad had differential wear across the bearing surface, with more wear on its backside

(M), compared to its front side (N). Multiple diamond surface inserts used for gage protection had broken parts and complete loss of diamond material and fractures were seen.

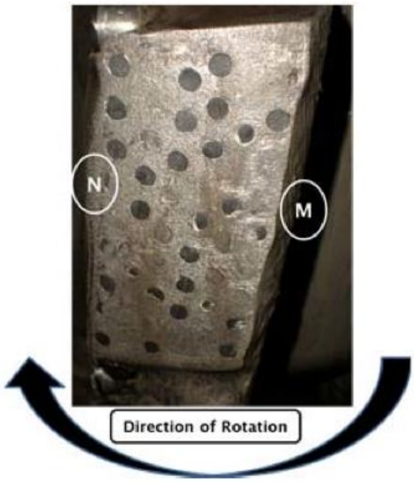

Figure 15: Gage pad condition [16]

The wear seen on the pad indicated detrimental contact between the pad and the borehole wall. If the wear had been evenly distributed across the pad, without diamond table fracture, that would represent normal pad action. The bit was pulled in gauge, in a non-abrasive environment and hence the wear on the pad was unexpected. The differential edge seen in the vicinity of the sharp edges implied that the pad had actually been trying to cut the formation, and the location of the wear discredits that sharp edges on the back of a pad have no cutting tendencies, due to the bit´s forward rotation [16].

4.3.2 Field validation

The recommended modifications described previously were incorporated into a drilling system, designed to drill through an 18 1/8”×21” salt section on a deepwater project (Well B). A direct offset well had previously been drilled through the same section, with identical hole sizes and wellbore configuration (Well A). Well B was drilled with the same BHA design, bit/reamer types and drive system. The only change made to the assembly in Well B was that the bit and stabilizer had bevelled edges [16].

Well A, with sharp edge geometry on the components, was plagued with several challenges, such as vibrations, over-torqued connections, RSS tool challenges and low ROP. Well B on the other hand, experienced none of the same challenges. Figure 16 displays the shock and ROP recordings for the two assemblies. Note that significantly reduced vibration level and increased ROP were recorded for Well B [16].

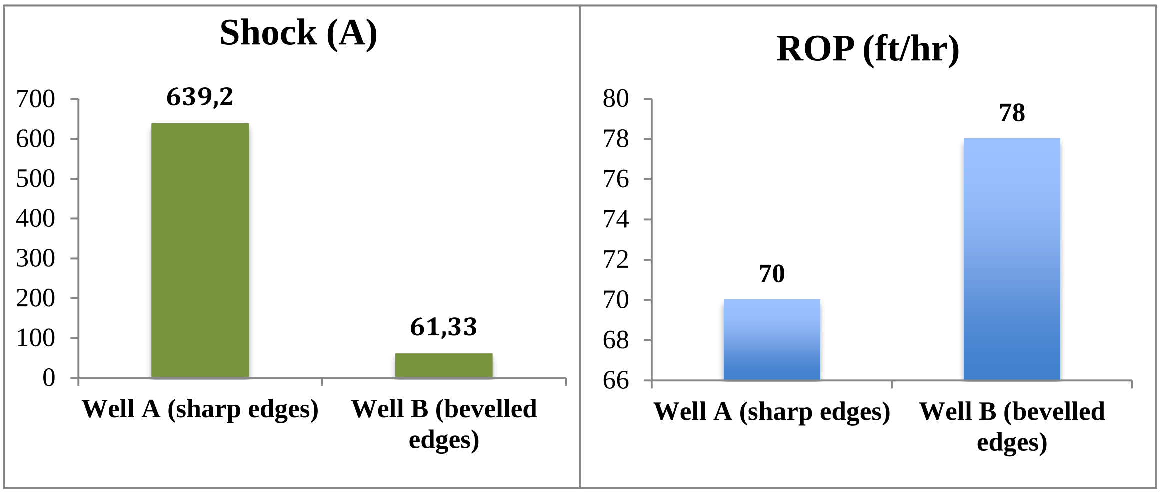

Figure 16: Shock level and ROP for Well A (sharp edges) and Well B (bevelled edges) [16]

4.4 Roller reamers

Using roller reamers in hard rock formations to mitigate tight hole on connections and trips have been performed for decades. While the application is not new, the industry has not always recognized that oscillating whirl-induced features are a large source of poor borehole behaviour, leading to problems such as hole enlargement. Other operational practices, including comprehensive management of vibrations in real-time, have reduced the severity of these features. However, even with contemporary practices, roller reamers may still be considered when field experience indicates that whirl-induced features remain challenging for tripping.

Roller reamers are commonly used for hole conditioning and their ability to decouple stick-slip does not seem to be fully appreciated by the industry. If whirl becomes present in a well, lateral vibrations induce strong side forces in the stabilizers and the frictional drag generates high level of torque at the stabilizers. This may in turn lead to stick-slip. When coupling occurs, a torsional vibration limit of the drilling system often prevents the driller from running sufficient WOB to prevent bit whirl, as this can drive the string into stick-slip. In such conditions, replacing the stabilizer with a roller reamer can reduce the potential for torque generation at the contact points. The driller may raise the WOB, as more torque becomes available to the bit, resulting in reduced level of bit whirl and increased ROP [17].

Whirl in the BHA cannot be completely eliminated and some side loading will exist at the contact points. As shown in figure 17, roller reamers change the interaction between the wellbore wall and the contact points, by introducing a low-friction bearing between the BHA and the wellbore wall. Roller reamers do not necessarily reduce the BHA whirl force. However, if additional torque can be applied to the bit by removing the fluctuation torque absorbed by the stabilizers, bit whirl may decrease. The mitigation of whirl at the bit leads to less severe whirl-induced patterns, and hence a smoother hole that is more in-gauge is obtained. When the hole is in-gauge the stabilizers will have less room to accelerate laterally, as a result of BHA whirl. Consequently, the side forces generated by BHA whirl are reduced, compared to the side forces recorded in a borehole enlarged by bit whirl [17].

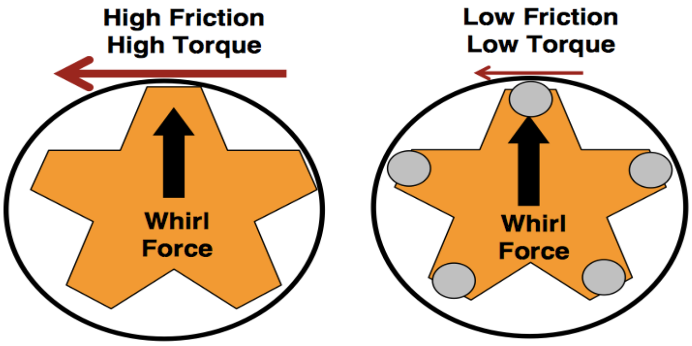

Figure 17: Roller reamers prevent conversion from lateral whirl forces into torque [17]

A significant portion of the improvements in borehole quality the industry has historically observed when using roller reamers, might be correlated to the indirect effect that they enable the driller to run appropriate drilling parameters to reduce or eradicate bit whirl. However, the most well-known attribute of roller reamers is that they smooth whirl-induced borehole features, as they are run full-gauge and have tungsten-carbide roller inserts. The roller reamer may reduce a dogleg and patterns generated by whirling with its cutting structure [17].

It should be mentioned that the tool life at operating conditions is not unlimited. The roller reamer life is highly dependent on downhole operating conditions, exposure to vibrations and heat generation [17].

4.4.1 Field validation

Case history 1 – replacing upper stabilizer with roller reamer

Two case studies are presented to illustrate how roller reamers can contribute to minimize shock and vibration. For the first case study, four extended-reach wells were drilled on the same field in the 12 ½" section. Wells A and B were drilled with identical BHAs with conventional stabilizers, while Wells C and D replaced the top stabilizer with a roller reamer. Wells A and B experienced somewhat less lateral vibrations than Wells C and D. However, the lateral vibrations experienced in Wells A and B appeared to have initiated stick-slip. The stick-slip recorded in Wells C and D became low and uniform regardless of the level of lateral vibrations. The roller reamer BHAs showed no sign of coupled response, enabling increased torque to be transferred to the bit and thereby allowing for increased WOB. The roller reamer BHAs improved the drilling efficiency by providing smoother wellbores and by reducing the energy needed to drill the wells [17].

Case history 2 – roller reamers in vertical conglomerate interval

In the second case study, four wells were drilled into a hard conglomerate interval. All wells used roller reamers in the section. Several trips had normally been required to drill through the interval in offset wells (not utilizing roller reamers) and whirl-induced borehole features often led to tripping problems. No problems in the footage drilled were recorded after implementing roller reamer BHAs. The roller reamers served to decouple whirl and stick-slip and thus allowed more WOB to be applied. Both level of bit whirl and the amplitude of whirl-induced patterns were most likely reduced. As it was drilled deeper, a roller reamer had to be replaced with a stabilizer, as the bearing became slightly loose and no backup was present. Bit and BHA configuration stayed the same and the stabilizer had similar dimensions to the roller reamer. When drilling with the stabilizer instead of the roller reamer, drilling progress became slow and severe surface vibrations were yet again recorded, as lateral vibrations coupled torsional vibrations [17].

4.5 Anti Stick-slip Technology

Vibration mitigation methods have continuously progressed in recent years, leading to tools being developed exclusively to minimize detrimental shock and vibration.

An innovative method has been introduced to the industry, potentially leading to lower risk of cutter induced stick-slip and BHA failure, when drilling mixed formations. The Anti Stick-slip Technology (previously named Anti Stall Technology) has several claimed benefits [18]:

- Reduces the torsional vibration tendencies
- Increases the ROP
- Releases energy that can be used to manipulate drilling parameters and thereby reduce the axial and lateral vibration level
- Improves the bit efficiency

It can be difficult to predict bit-induced vibrations produced through rapid transitions in subsurface formations and equally hard to avoid them by preselecting bit and drilling parameters. AST is based on a dynamic, self-supported downhole mechanical system that actively controls the bit torque by manipulating the DOC. The system automatically adjusts the drilling torque to counteract the torsional peak loads and stalls [19]. The functional principle is relatively simple and indications suggest that it has been successful in reducing the vibration tendency in several applications, also including underreamer operations

The AST tool can be placed in the lower part of the BHA and thus makes it possible to quickly prevent the bit from stalling and thereby limit the risk of developing severe stick-slip vibrations. As mentioned, aggressive bits have a tendency of generating stick-slip as they dig deep into the rock. The mechanical function of AST is to convert the rise in the drilling torque that precedes a stall into an axial contraction, immediately cutting back the WOB. The reduction in WOB will reduce the DOC enough for the bit to keep on rotating. The conversion to axial contraction is seen as a reduction in the length of the helical spline. The spring and absorber is simultaneously compressed internally in the tool body above the telescopic unit, see figure 18. The absorbed energy in the spring is then fed back through the system to maintain steady torsional load. The AST tool begins to work just as the cutters begin to stall. With the torque stability continuously optimized the tool can potentially lead to increased drilling speed [19].

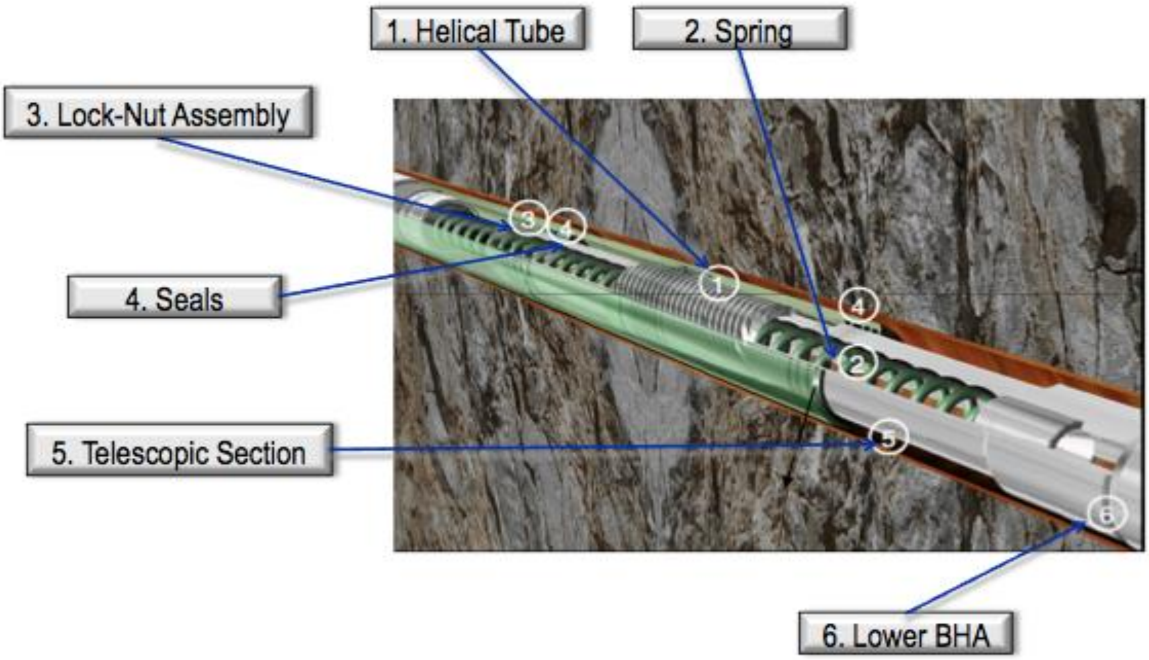

Figure 18: Components of the AST tool [20]

The tool has also been utilized when torsional vibrations are generated by the drillstring interaction with the borehole wall, compromising the quality of the real-time information from the MWD tools. During this situation, the strongest oscillations often appear as the lower part of the string goes into compression. As a result, it becomes challenging to separate friction-induced oscillations from bit-induced effects. In this situation, the principle is that the closed loop function will decouple the friction induced string oscillations from acting on the bit, potentially preventing accumulation of stress and vibrations in the lower part of the BHA. AST will at the same time work to stabilize the oscillating input energy, and might provide improved bit efficiency and ROP results [19].

It is preferable to place the AST tool as close to bit as possible, often on top of logging BHAs, including stabilizers, to abate vibrations early on and supress stick-slip generated at the bit. However, the tool has been positioned both under and over the MWD and still maintained its functionality. In underreamer applications the tool should be placed above the reamer.

4.5.1 Field validation

In this section Statoil experiences with the AST tool is shared to quantify the effect for future use.

Statoil quantifies the effect of AST on Ullrigg

Statoil cooperated with the inventor of AST (Tomax) in 2006 to develop a prototype tool for a qualification process based on the need to drill a deep exploration well in pyroclastic rock. Two prototype tools were developed, one adapted to the 12 ¼" hole section (8 ¼" OD tool) and a 6 ¾" OD tool to enable enhanced flexibility for field trials. To verify that the tool behaved, as it should, and to confirm that the tool were safe for use in future operations, two tests were conducted. For both tests, two runs were performed, with and without the tool for purposes of comparison.

In the first test an 8 ¼" AST was placed above a PDC bit in a rotary hold assembly at the Internal Research Institute of Stavanger (IRIS). The formation under the test rig, Ullrigg, have a history of generating severe stick-slip and cause damage to the PDC bits, making this a perfect opportunity to validate the effect of AST. The parameters were kept similar for both runs by using identical bits. The WOB was increased in steps for both runs and the length drilled was kept short to reduce the risk of interference from formation changes [21].

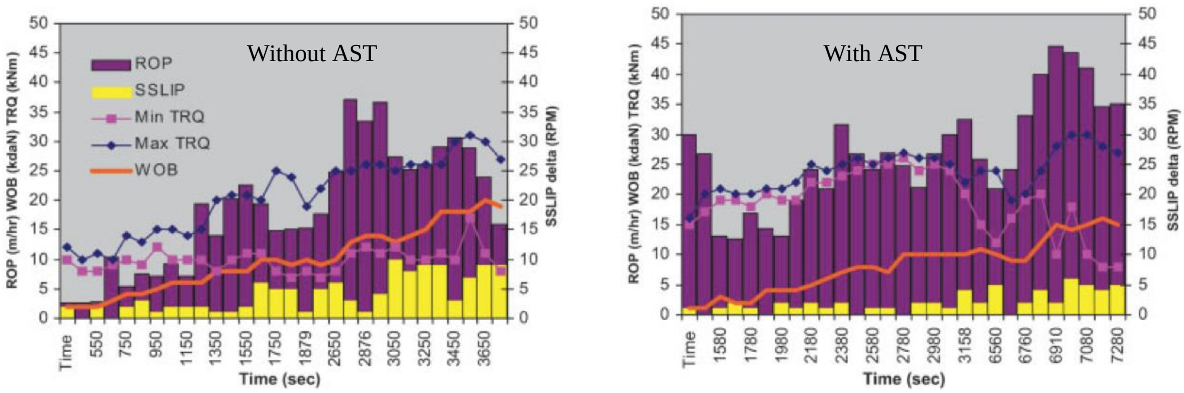

Figure 19: Drilling parameters on Ullrigg without and with AST [21]

By analysing the results in figure 19, it is clearly seen that the ROP is significantly increased for the run with AST. In addition the torque is less erratic, indicating reduced stick-slip level. It should also be added that the bit in the AST run had its full cutting structure intact, whilst the bit from the reference run had chipped cutters. From the graphs it is seen that AST serves to its purpose, by minimizing stick-slip and increasing the drilling speed.

The second test was performed to determine the effect of the tool in underreamer operations. An 8 ¼" AST was utilized. The bits used were identical to the ones used in the first test and the reamer was a three bladed hydraulically operated reamer with PDC cutters. A reference run was drilled without AST for comparison and the mechanical integrity of the tool was proved. It was documented that the AST tool prevented torsion peaks when all weight was distributed on the reamer and opened a larger operational window for the underreamer in terms of weight [21].

It should be mentioned that at a later stage the tool experienced some mechanical integrity issues. On one occasion severe stick-slip was recorded after the tool jammed under extreme bending, and the AST tool suffered fatigue failure. However, after the second bending fatigue incident a new tool was developed for higher bending requirements. Some failures in the pressure seals, leading to loss of oil and deteriorated wear on the tool internals were also recorded and this was addressed by an optimized seal system [21]. Based on this, experiences from 2006 should not affect future use, as the tool has been reinforced.

AST used in underreamer operation in the Gulf of Mexico (GoM)

The AST tool was used on Kilchurn, an exploration well in the GoM in 2012, with Baker Hughes as the lead contractor. The drillteam objective was to drill a 10 5/8"×12 ¼" section. The original hole was drilled with AST incorporated in the assembly, while for the sidetrack the tool was removed. The two wells were drilled with identical components, bit and lithology, making this a perfect opportunity to validate the AST contribution in underreamer applications [22].

CoPilot was run in the same position in both sections, providing advanced dynamics measurements. Real-time data were available for both sections and used to compare the two runs. In addition the mechanical specific energy (MSE) was plotted to compare drilling efficiency, due to intervals of controlled ROP in both sections. At this stage MSE should be defined. MSE takes torque, RPM, ROP, diameter of the bit and WOB into account and produces a value that can be compared to understand drilling energy. Drilling efficiency is the opposite of MSE, meaning that lower MSE indicate that less energy is needed to drill the hole section, resulting in higher drilling efficiency. The AST was optimally placed and was verified to be safely within its operational window [22].

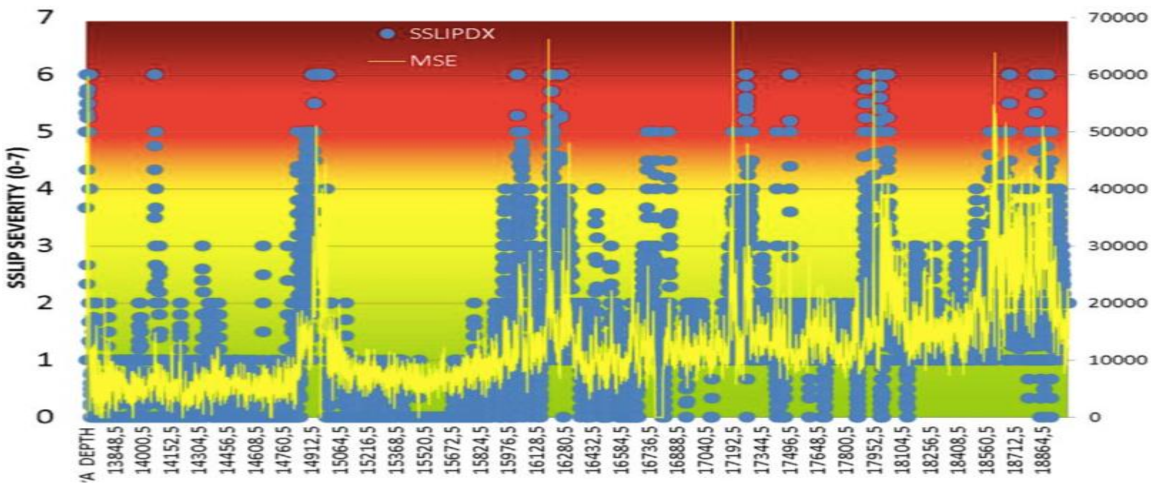

Figure 20: Stick-slip level for Kilchurn sidetrack (without AST) [22]

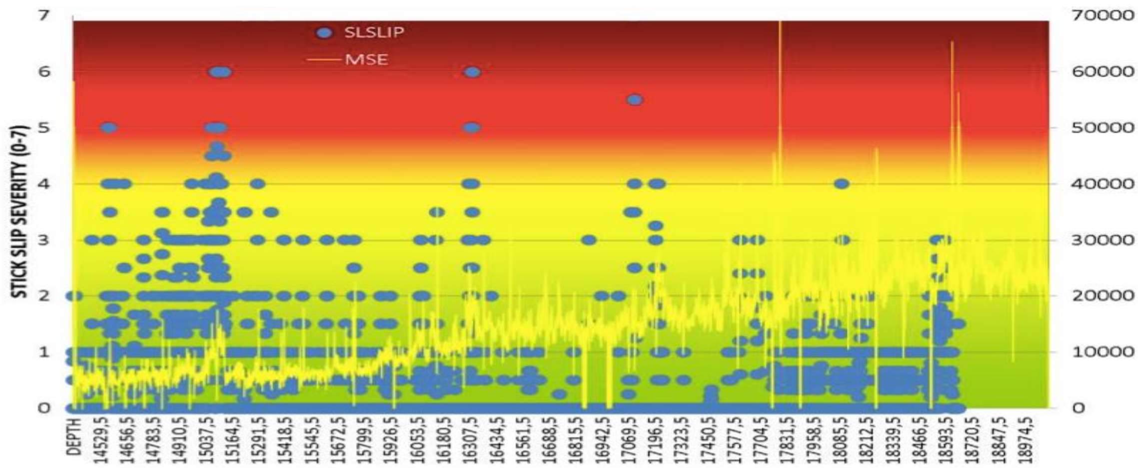

Figure 21: Stick-slip level for Kilchurn original hole (with AST) [22]

Figures 20 and 21 summarize the stick-slip tendencies for the Kilchurn runs with and without AST. Figure 20 displays the stick-slip tendencies for the well without AST, whilst figure 21 shows the recordings for the run with AST incorporated in the assembly. The sidetrack without AST, experiences longer periods of elevated stick-slip, leading to significant drop in drilling efficiency. As seen, the MSE ranges higher, meaning that more energy was needed to drill the well. The results look promising for the original hole incorporating AST, with overall low average stick-slip tendencies and occasional readings of elevated stick-slip. When looking at the graphs, the AST tool shows a distinct ability to reduce the stick-slip severity through six or seven difficult intervals. Good drilling performance was obtained through difficult layers when including the tool and hence it was put back in for the continuation of the well. Today, AST is used in most sections in the GoM, also in underreamer applications.

AST performance analysis by Schlumberger on Statoil operated fields

Schlumberger performed an analysis based on Schlumberger and Statoil DBR data (2008-2010). The objective was to compare BHAs with and without AST, to validate whether or not the tool add value to the drilling system. 80 runs with the AST tool and the same amount of runs without AST were investigated, making this the largest analysis to date. For the first analysis all runs were evaluated, without filtering applied. Results showed 32% higher ROP with AST in the BHA, compared to the runs without AST. Less tool failures were seen, and runs with AST produced more m/run. The pie charts in figure 22 provide an overview of the failure ratio for these runs [20].

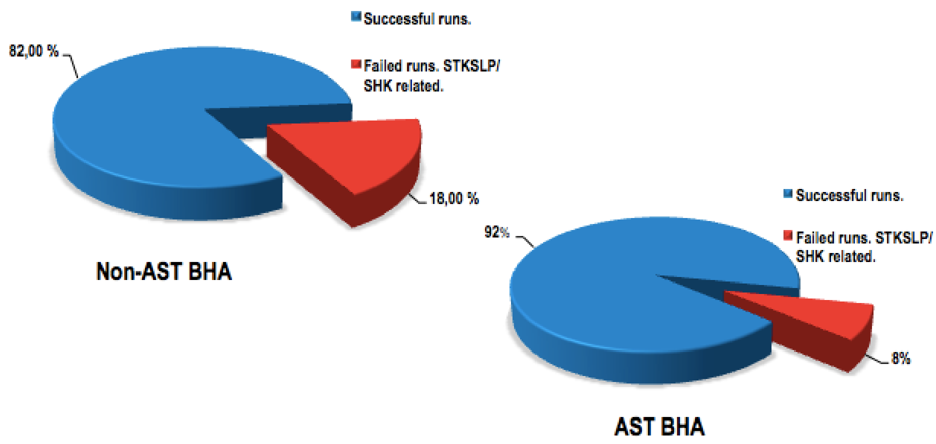

Figure 22: Failure ratio for 79 runs with and without AST [20]

It is important to keep in mind that several factors could have affected the drilling results, such as formation type, bit type and BHA components, and these were not considered in the previous analysis. To properly quantify the effect of AST, two wells should be drilled next to each other under identical conditions. As this was not possible, the second analysis was based on the most identical runs drilled under the same drilling environment, in the same formation type, using similar bit type and BHA, with and without AST. Only runs fulfilling these inquiries were selected. The most identical runs were eventually filtered out. A detailed analysis was performed on these runs and results showed 17.3% increased average ROP for the AST runs. Drilling parameters were enhanced, reducing the stick-slip with 45% and dramatically reducing the shocks [20].

An example taken from the report clearly illustrates the effect of drilling with AST. In this example two runs were performed in identical formation layers, with identical bit types and drillstrings. The difference between the runs was that one incorporated AST while the other had a non-AST BHA. An 8 ½" section was drilled, resulting in tool failure and the need to pull out of hole (POOH), without AST incorporated in the assembly [20].

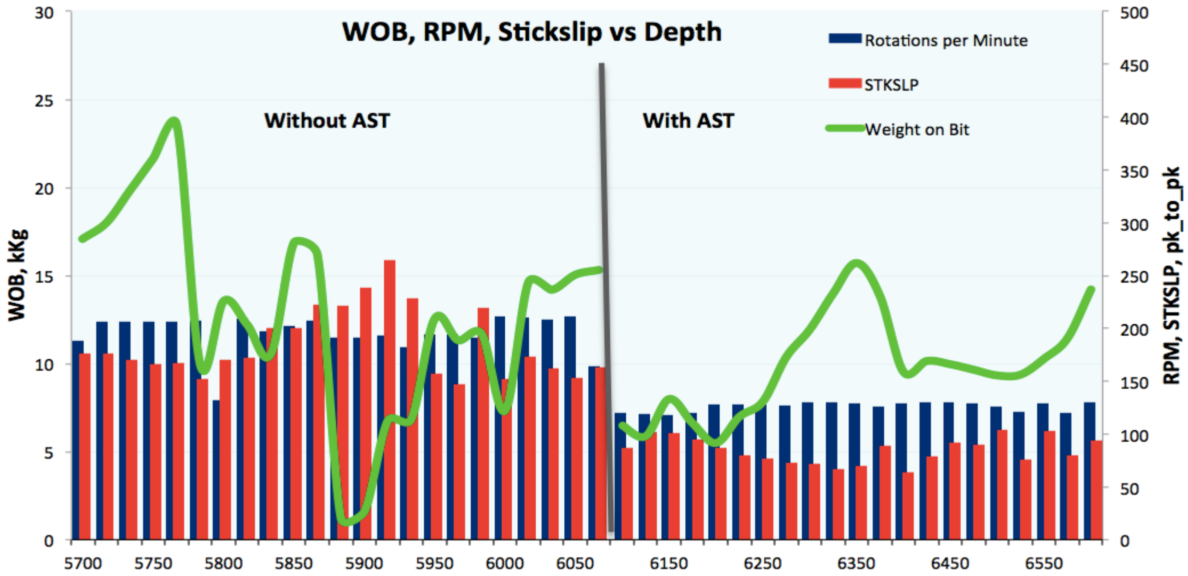

Figure 23: Drilling under identical conditions with and without AST [20]

The recordings in figure 23 displays the drilling parameters and stick-slip level for both runs. For the run without AST the RPM is relatively high (approximately 170 in average) and both ROP and WOB are unstable. Note that the stick-slip level in this run is high and evenly distributed, exceeding the tool specification limits set by Schlumberger. The high stick-slip level explains why the RPM is abnormally high and why the WOB is reduced several times, as the drill team most likely tried to mitigate the stick-slip event. The RPM for the AST run is stable and approximately 110 in average. The WOB is relatively high and stays more stable throughout the run. The most important feature of the second run with AST is that significantly lower stick-slip level is measured, never exceeding the Schlumberger limits. Consequently, the BHA with AST is more stable and less affected by destructive stick-slip tendencies.

In the Schlumberger report it was concluded that the AST tool in fact enhanced the ROP, tool reliability and service quality. In the report it was stated that the implementation of AST can potentially lead to advantages for both Statoil and Schlumberger. AST can lead to reduced costs and NPT, by enabling more efficient drilling, reduced stick-slip, fewer tools running out of spec (OOS) and less tool failures [20].

<u>AST experiences in the 12 ¼”×13 ½” section</u>

Statoil have used AST on several fields and in numerous runs. To get an overview of the effect of AST in underreamer operations, the Statoil operated fields that have used the tool most frequently were preselected. Through conversations with field engineers and Statoil employees, experiences with AST were shared. The results are presented in table 9.

When reviewing these results, it is important to keep in mind that several factors could have affected the BHA performance, ROP values and stick-slip recordings.

Table 9: Statoil experiences with AST in the 12 ¼”×13 ½” section

Field	Well	Supplier	Statoil comments
Oseberg	30/9-F-8Y1T3	Baker Hughes	The 12 ¼”×13 ½” section on Oseberg F-8 Y1 (T1/T2/T3) provide a good basis for comparison with and without AST, as three parallel sections were re-drilled. The objective was to shorten the spacing between the MWD tools and the reamer, to eliminate one hole-opening trip. By replacing three heavy weight drill pipes (HWDP) with AST, the spacing was reduced with 54m (177ft) for T3. T1 and T2 were drilled without AST. The tool was implemented in the assembly with positive experiences related to the use of AST in combination with underreamers and Shetland drilling. T1, T2 and T3 were drilled through stringers with the same RPM (140) and the results were exclusively positive for the AST assembly (T3). The overall stick-slip level was reduced and when the reamer drilled through the stringers high stick-slip levels were eliminated. The AST tool also provided smoother and lower surface torque and enabled both bit and underreamer to drill faster through the Shetland stringers [23].
Vigdis	34/7-D2AH 34/7-G2H	SLB	The AST tool was used in several 12 ¼”×13 ½” and 9 ½” sections on Vigdis. A comparative study on wells 34/7-D2AH (no AST) and 34/7-G2H (with AST) were performed in similar 12 ¼”×13 ½” sections. For similar build and tangent sections, the ROP for the run with AST was 50-60m/hr (160-200ft/hr), while the ROP for the run without AST was 40-50m/hr (130-160ft/hr). Torque values were somewhat higher for the non-AST run. With AST incorporated, the RPM was 150 and stick-slip level <50. For the run without AST the RPM was 170 and the stick-slip mostly in the range 50-75, indicating that the tool resulted in a small reduction in stick-slip. In recent years, drilling has been performed without AST on Vigdis. No negative results have been observed after the tool was excluded and sections have been drilled with ROP up to 70 m/hr (230ft/hr). Taking the price into consideration Statoil engineers have concluded that AST is currently not needed on this field [24].
Visund	34/8A-17H	SLB	Statoil ran AST in the 12-¼”×13-½” section in well 34/8A-17H in 2011. The objective for running AST was to protect the equipment through a 3900mMD clay section and hence increase the probability of drilling to target depth (TD) without round trips. The well could most likely have been drilled successfully without AST as well, as there were no hard stringers. However, Statoil had overall good experiences when running the tool in this well [25]. There is currently no need for AST on this field.

AST in thick chalk layers

Statoil made a report on the Dougal and McHenry wells, located close to the Sleipner field, which demonstrates the effect of AST in long, near vertical chalk sections. The similar exploration wells were drilled through Cromer-Knoll in the Norwegian North Sea and the main objective was to validate that AST mitigated drillstring vibrations and improved the ROP, as claimed. Downhole measured stick-slip and shocks were evaluated, in addition to key surface drilling parameters, in order to assess the validity of the claim made by Tomax.

AST was run in the 2nd 12 ¼" BHA, on Dougal (15/6-11S), whereas no AST was run in the 15/6-12 McHenry well, to enable a comparative study. Both wells were mainly drilled through long chalk sections. The wells had low inclination and absence of mechanical issues. Dougal was drilled with 16deg inclination, while McHenry was drilled vertically. McHenry showed high stick-slip for the first 6 hours, due to low RPM (<80), after which, stick-slip was 200 with >150 RPM (figure 24). The average ROP for the McHenry well was 35m/hr (115ft/hr), while Dougal showed an average ROP of 20m/hr (66ft/hr), with a markedly higher variance. McHenry recorded the highest average torque compared to Dougal, with relatively similar variance [26].

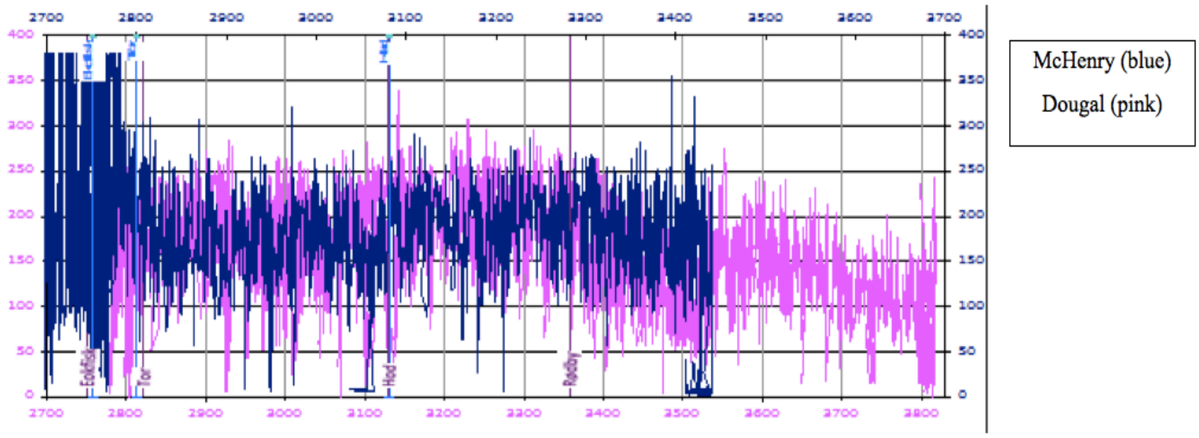

Figure 24: Stick-slip level for Dougal and McHenry [26]

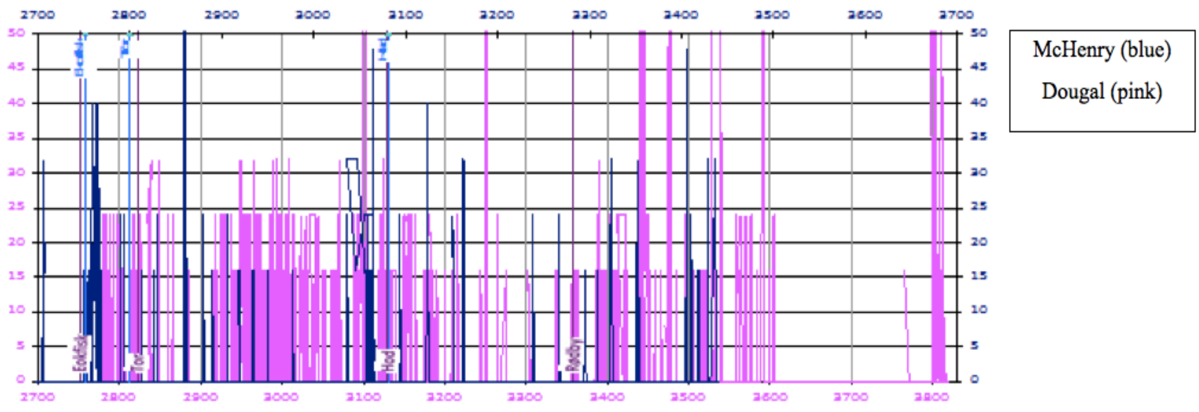

Figure 25: Shock level for Dougal and McHenry [26]

Figures 24 and 25, respectively illustrate the stick-slip tendencies and shock levels for Dougal and McHenry. The reference scale is adjusted to overlap the formation tops as closely as possible. As seen from the figures, the two wells have relatively similar stick-slip tendencies, which appear to be formation-dependent. However, the stick-slip plot displays somewhat lower scatter for the McHenry well compared to Dougal. This finding contradicts the claim made by Tomax, that the AST tool will reduce the stick-slip tendencies. In addition, the shock plot illustrates fewer shocks for McHenry (without AST), compared to Dougal (with AST). Based on this, indications suggest the tool does not serve to its purpose in long chalk intervals that are nearly vertical. The stick-slip level and shock level were increased for the AST run and the ROP reduced.

4.6 Frank´s HI tool

Frank´s HI tool is an on-bottom anti-vibration tool designed to supress axial and lateral vibrations generated by the drill bit dynamics. The tool is normally placed directly above the bit and can potentially serve to decouple the different modes of vibrations between the drill bit and the drillstring. Figure 26 displays the main components of Frank´s HI tool.

Figure 26: Components of Frank´s HI tool [27]

In contrast to AST, the HI tool does not incorporate a spring, but rather a knuckle joint with compression rings incorporating rubber. This makes it possible to capture and then dissipate the energy rather than store it. The lower section of the tool absorbs and dissipates axial vibrations, whilst the rubber element on the upper section of the tool absorbs and dissipates lateral vibrations. The upper anti-vibration ring, flow tube and lower anti-vibration rings act as dampening springs and allows the tool to briefly deflect under load. Frank´s HI tool is unique as it contains a non-rotating stabilizer, which has contact with the wellbore and thus dissipates the vibrations energy back into the formation smoothly.

According to the inventor (Frank´s International), the tool has several attributes, including [28]:

- Limits axial and lateral vibration challenges in difficult formations, reducing the NPT
- Reduces the dynamic interaction between the BHA and the drill bit with a flexible geared connection
- Decouples the BHA and mud motor harmonics from drill bit and drillstring
- Decouples drillstring harmonics from the BHA
- Provides a dynamically self-centred bit even if the BHA is tilted. The bit is centralized, hence BHA imbalance and hole enlargement are avoided
- By supressing axial and lateral vibrations more energy becomes available. This energy can be used to adjust the drilling parameters to prevent stick-slip

Claimed benefits:

- Increased ROP in hard formations
- Extended bit life
- Top-drive damage prevention
- MWD/LWD damage prevention
- Wellbore integrity improvements
- More aggressive bits are tolerated

Frank´s HI tool is compatible for any bit or BHA type, including PDC and RC bits, and can supposedly be placed anywhere within the BHA according to application. Several derivations of the tool have been designed in multiple sizes in order to cover most applications of the tool; particularly where complex rotary steerable directional requirements are required. A standard tool has been developed together with a tool specifically designed to be placed below RSS tools. From the run list it was confirmed that both tools have been run in the North Sea for complex build and turn applications. There are special geometric requirements to allow for bit tilt when running the tool below the RSS, as well as shortening of the necks to optimize the bit-to-bend distance. Placement of the tool is critical to abate any vibration condition onset, at or close to the point where it is generated, see figure 27 [29].

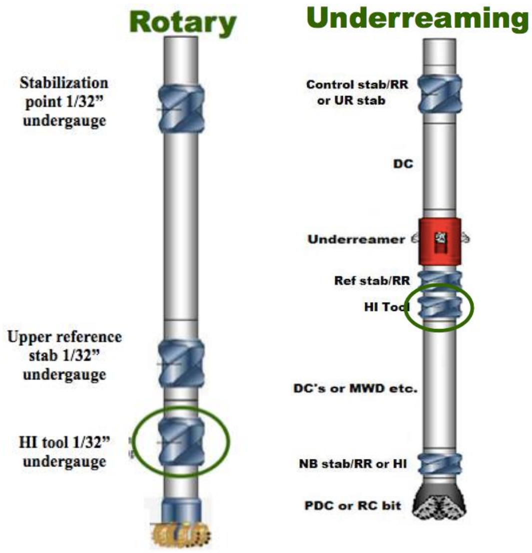

Figure 27: Placement of Frank`s HI tool, in rotary BHA and underreamer BHA [27]

4.6.1 Field validation

In this section several comparative field experiences are shared to provide an indication on the effect of the HI tool. A specific experience where the HI tool is used in a milling operation is described, to shed light on its effect in other applications, were Statoil is currently not using the tool.

<u>Frank´s HI tool mitigates vibrations generated by the underreamer</u>

A case study from onshore Val DÁgri, an Eni operated field, illustrates the benefits of the HI tool when run together with AutoTrak and a PDC bit. The field located in South Italy consists of extremely hard formations, increasing the risk of shock and vibration. Prior to implementing the HI tool, vibrations generated at the underreamer moving down into the MWD/LWD were detected, bits were frequently broken and MWD tool failures were seen. Recordings were made for the 12 ¼”×13 3/8” section with the HI tool mounted below the underreamer. To prove the effect of the tool, Black Boxes (downhole dynamics recorders provided by NOV) were placed above and below the HI tool, making it possible to compare the lateral readings recorded below the underreamer compared to the lateral readings below the HI tool. By comparing the readings above and below the HI tool, the claimed effects were verified and great results were recorded [27]:

- 4,6% less low level lateral shocks
- 89,1% less medium level lateral shocks
- 70% less high level lateral shocks

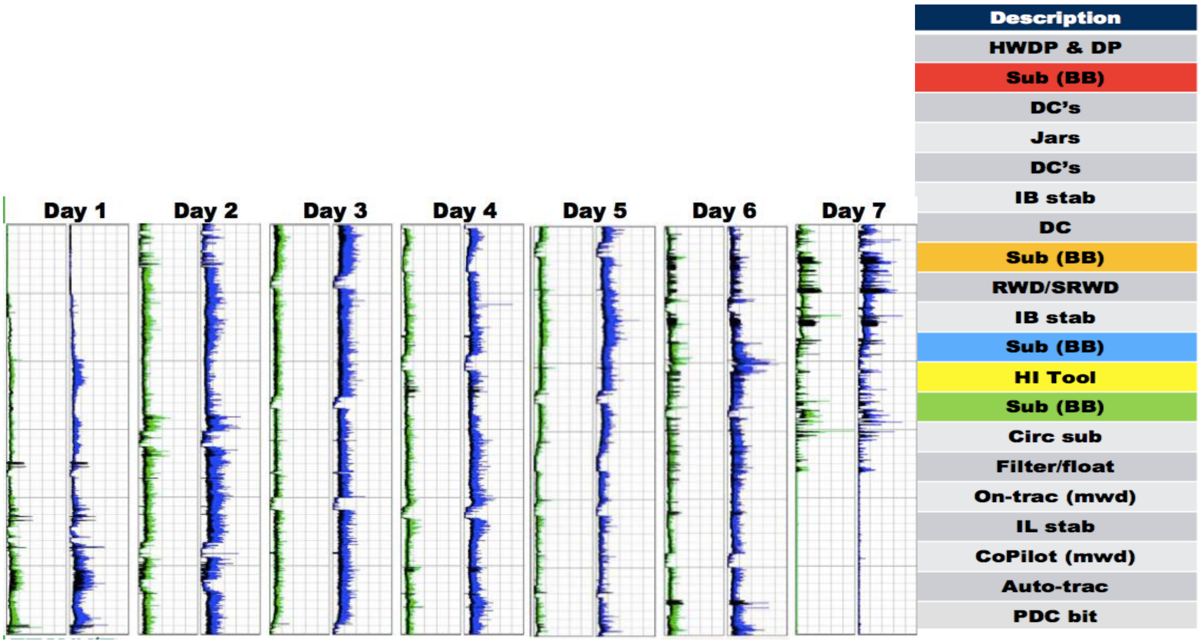

Figure 28: Black Box readings and placement on Val DÁgri [27]

Figure 28 shows the Black Box data recorded on Val DÁgri. When analysing these recordings it is clearly seen that the HI tool served to its purpose, decoupling the BHA harmonics from the bit, and reducing the vibration level. The blue scattered line displays the lateral readings from above the HI tool, recording vibrations generated at the underreamer, moving downwards in the assembly. Higher vibration spikes and higher average vibrations are recorded in this position. The green line displays the lateral readings recorded below the HI tool. After passing through the HI tool the vibration spikes are less severe and the average lateral readings are overall reduced. Based on these recording, it is demonstrated that the HI tool absorbed and dissipated the vibrations coming down from the underreamer, and hence prevented the vibrations from affecting the components further down in the assembly.

<u>Frank`s HI tool mitigates vibrations generated by the bit</u>

BP utilized the HI tool in a 26" section on a North Sea project. Recordings implied that vibrations generated at the bit were moving upwards in the assembly, causing damage to the top-drive. The HI tool was placed near the RC bit and Black Boxes were mounted above and below the HI tool to validate that the tool dissipated the vibrations as expected. The Black Boxes confirmed that the HI tool lowered the lateral spikes, consequently reducing the shock levels [27]:

- 15% reduction in low level shocks
- 61% reduction in medium level shocks
- 84% reduction in high level shocks

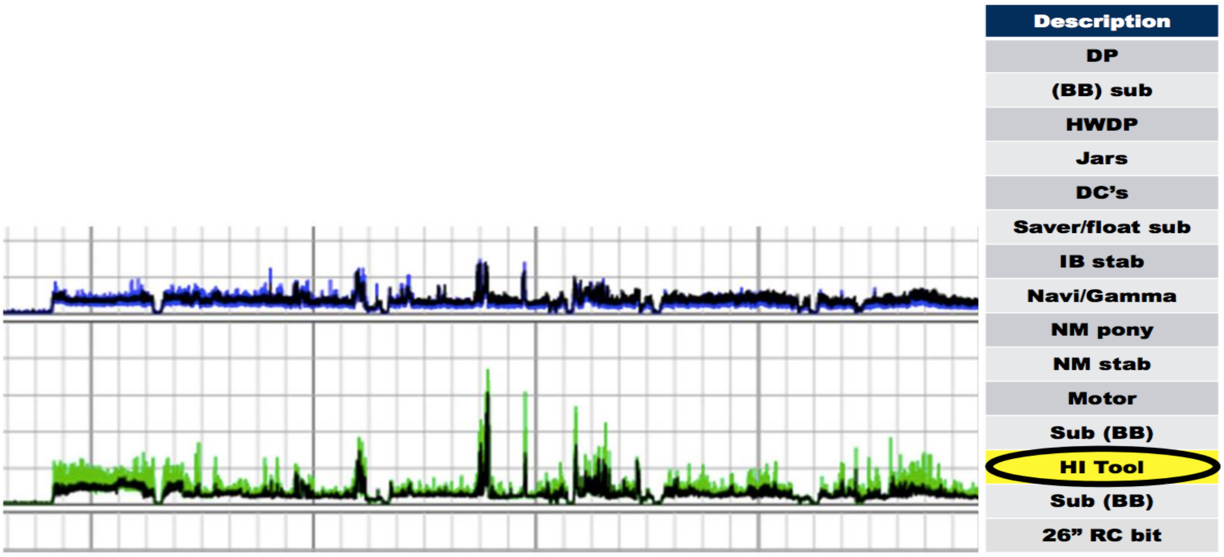

Figure 29: Black Box readings and placement in North Sea operation [27]

A closer look at the downhole vibration measurements are provided in figure 29. The green line displays the lateral readings recorded directly above the bit. Note that the peak levels are significantly higher compared to the lateral readings recorded above the HI tool, provided in blue. After the vibrations passed through the HI tool, reduced peak values are seen. The tool decoupled the bit from the rest of the BHA, preventing severe vibrations generated at the bit from travelling upwards in the assembly.

Frank´s HI tool in milling operations

Large operators such as ConocoPhillips have used Frank´s HI tool to achieve aligned milling solutions in multiple operations. In this application the HI tool is placed directly above the mill blades and the taper mill (see figure 30), potentially minimizing shock and vibration during the operation.

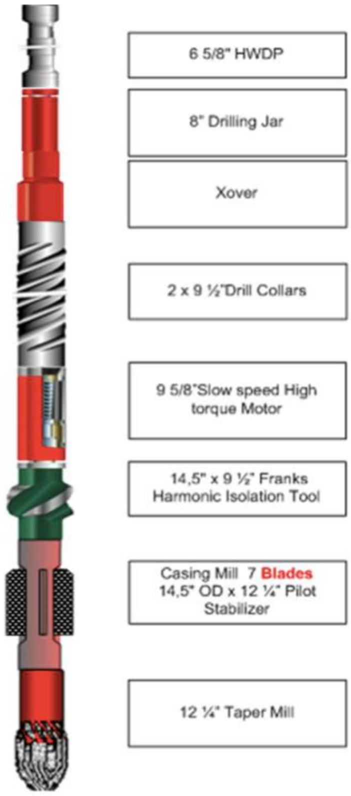

Figure 30: Placement of Frank´s HI tool in milling operations [30]

To illustrate how Frank´s HI tool can be used to improve milling operations, a case study were Baker Hughes used the tool, while milling on an offshore Norway project, is presented. For this operation Black Boxes were run in the assembly for proper verification of the tool performance. Run 1 was performed with 10 blades P3 cutters, without incorporating the HI tool in the BHA. After drilling from 140m to 203m (460ft to 666ft), tapered wear was observed on the casing mill. The casing had been milled 63m (206ft) at 2.3m/hr (7.5ft/hr) and detrimental vibrations, and NPT due to top drive problems, were observed. The next two runs (run 2 and run 3) were performed with 10 blades metal muncher cutters and the HI tool was now incorporated in the assembly. Less vibrations and improved performance results were recorded, compared to the first run. In run 2 it was pulled out of hole due to lack of progress, possibly due to junk downhole. The mill had good cutting shoulder and had been tracking lower casing. After run 3, top drive inspections were reduced from once every four hours to once per shift. Disregarded the time spent repairing the top drive on run 1, two hours of NPT was saved per 24 hours between run 1 and run 2. Run 4 contained 10 blades with P3 metal cutters and the HI tool was still incorporated in the BHA. Consistently low vibrations were recorded throughout the run, increasing the milling speed and performance. The last run (run 5) was performed with 10 blades and P3 cutters, without the HI tool. The mill was 50% worn with several ledges seen. The vibration level was reduced (probably related to depth), but the milling speed significantly decreased. It is possible that the vibration levels were higher at the cutting surface, but these vibrations were not seen at surface [30].

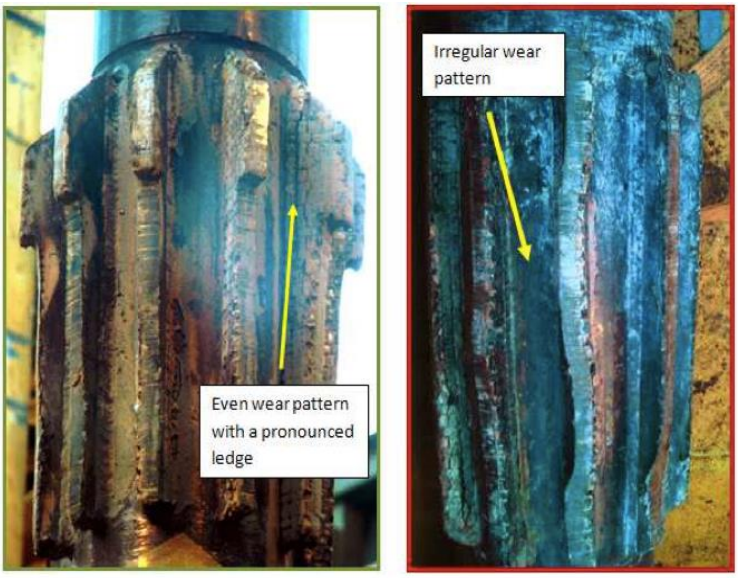

Figure 31: Wear pattern on milling blades with and without the HI tool [30]

In figure 31, the wear patterns on the mill are compared to an offset well milling without the HI tool. Both wells milled with P3 cutters at comparable depths. Notice that milling without the HI tool (right hand side) led to irregular wear pattern and tapering of the mill blades, due to surface and downhole vibrations. The mill´s cutting insert structures were not utilized to produce the optimum performance. When using the HI tool, the wear pattern on the mill blades was uniform and consistent (left hand side). The cutting shoulder on the mill indicated that the mill had been centralized, tracking the lower casing and prolonging the mill life. The client stated: "With the right combination of BHA, cutter selection and inclusion of the HI tool, a standout run was achieved, 221m (724ft), and the operation was completed in 14 days" [30].

Statoil experiences with Frank´s HI tool

Frank´s HI tool has been utilized in numerous runs all over the world, indicating successful results. Statoil has for the time being (March 2014) only used the tool on Brugdan II, Johan Sverdrup and Troll. To get a proper validation on the effect of the tool, Statoil engineers working on these fields, when the tool was implemented, have shared their experiences. The experiences gained during these operations are valuable for future use.

Brugdan

Black Boxes were utilized on the Brugdan II well, both in the 12 ¼" and the 8 ½" section, to quantify the effect of Frank´s HI tool. Post-drilling Statoil reviewed the data and experienced some struggles in quantifying the effect of the tool. However, it was concluded that the HI tool positively impacted the vibration level, reducing the vibrations with 16-27%. It was determined that there were no adverse effects from including the HI tool and thus only positive outcomes should result from implementing the tool [31].

Johan Sverdrup

Frank`s HI tool was also utilized by Statoil on Johan Sverdrup in 2012. On this field moderate to severe downhole vibrations were experienced in previously drilled 8 ½” sections and thus the HI tool was incorporated in the assembly to abate the vibrations. For the Johan Sverdrup fault margin mainbore a rotary BHA was used and the HI tool was run close to the bit. Black Box data showed very low vibration level in all BHA positions; near bit, above the HI tool and in the drill collars. Overall, lateral and torsional vibrations were very low, keeping within the recommended threshold. It is hard to conclude what effect the tool had in this run, as the vibration level was low both above and below the HI tool. For the sidetrack an RSS BHA was used and hence the HI tool was placed higher up in the BHA, above the MWD collars. A near bit position could be achieved with RSS as well, but Schlumberger are reluctant to place tools near bit. Slightly higher dynamic response was recorded compared to the mainbore. However, the overall vibration level stayed very low.

Schlumberger reported positive experiences when implementing the HI tool in the BHAs on the two Johan Sverdrup fault margin wellbores. This is a good indication that the tool is beneficial. Statoil investigated this further and discussed the functionality and benefits with Schlumberger. It was stated; “having the HI tool made it easier/faster for us to mitigate the vibration than on wells that have not had the tool in the BHA” [32].

Troll

While writing this thesis a HI tool run was performed on Stena Don (April 2014), on the Statoil operated Troll field, with Baker Hughes as the main contractor. The tool was run in the 12 ¼”×13 ½” section and tool failure were detected after 16.7 hours of drilling. Prior to the tool failing lateral vibrations were low, recording some stick-slip. Drilling progressed normally with expected ROP and both supplier and operator were satisfied. The rig stopped for weather and after the operation was restarted the tool showed good vibration tendencies for another 30m (98ft), until it failed. It was determined that torque transfer through the tool was no longer possible. No pressure loss, torque spikes or washouts were recorded, but the ROP dropped to 1m/hr (3.28ft/hr). A rubber element was seen sticking out of the tool, without jeopardizing the functionality of the tool or leading to failure. The real problem leading to tool failure was that the upper part of the HI tool could rotate freely from the lower part of the tool, indicating a malfunction. 120RPM was applied at surface, but the bit stopped rotating immediately after the upper part of the HI tool started rotating. The run on Stena Don was a standard underreaming run and hence similar operations with identical tool placement (below the underreamer), drilling conditions and parameters (110-115RPM), have been performed successfully previously.

After Frank`s International opened an investigation on the tool, worn down splines were detected. It appeared as though the sleeve had travelled down, allowing the splines to disengage and wear down. The root cause analysis, requested by Statoil, suggested that the tool was clamped around the sleeve area during pre-make, causing the locking ring to loosen and allowing the sleeve to move downward. The sleeve should not be grabbed by torque machines or the iron roughneck, but should rather be handled by fish-necks, as normal. Frank`s International will prevent this from happening in the future by marking and specifying that the tool must be handled by a fish neck only, and by having a man present for any pre-making [33]. It is important to emphasize that neither Frank´s International nor the directional drilling suppliers have experienced similar issues previously. This was a one-off failure and should not prevent future use.

4.8 Other tools for reduced vibration levels

It is important to mention that several other tools and procedures exist on the marked for vibration mitigation, some of these tools are mentioned below:

- V-stab, reduces the stick-slip tendencies and lateral shock by introducing forward synchronous whirl
- Shock subs, absorbs vibrations and decreases the level of detrimental drillstring vibrations
- Mud motors, not primarily a vibration mitigation tool, but can serve to reduce stick-slip vibrations generated by the bit

These tools will not be described in more detail, as better solutions exist.

5. Tools and techniques to minimize vibrations in underreamer operations

In commercial drilling, underreaming is performed in all types of wells and is to this date considered a standard practice in many drilling operations. Underreamers are placed above the bit in the drillstring and are used to enlarge an existing borehole in order to improve the clearance for tripping out/in with BHA, tubular and casing. When looking further into underreamer drilling it was found that, although underreamers have several advantages, they represent a concern to the operator. While drilling the pilot hole and at the same time opening it up to target diameter the drillstring experiences cutting forces simultaneously at the bit and underreamer. The cutting forces at the reamer are known to trigger severe generation of drillstring vibrations, potentially harming the BHA. Such problems have led to NPT and increased costs.

Concentric expandable reamers can pass through restrictions in closed mode and are activated and utilized mechanically or hydraulically. The arms with cutting elements are activated making the borehole larger. The cutter blades are normally placed at an equal distance around the tool and are balanced. Concentric expandable reamers can be applied in reaming while drilling (RWD) applications placed in the uppermost section of the BHA and can be utilized in conjunction with RSS [34]. Both eccentric reaming devices and concentric devices, with balanced cutting forces, lead to increased level of vibration and failure. However, eccentric underreamers are normally associated with more vibrations and poorer hole quality.

The span length between the bit and the underreamer can reach 45-50m (148-164ft). Vibrational issues arise when the bit and underreamer drills into different formations with diversified hardness. When the bit is in hard formation most of the weight will be on the bit, when drilling into different formations the weight distribution will shift. If the bit has reached softer formations, while the underreamer is still in a hard formation, such as hard calcite stringers, more weight is transferred to the reamer, creating uneven drilling. These conditions often lead to downhole vibrations. The irregular drilling makes the position of the MWD tools particularly vulnerable to vibrations and has several times led to MWD failure.

The borehole above the underreamer has a larger diameter than all the components included in the drillstring and thus every tool, including the reamer, have the ability to move laterally. As described in section 2.2.2, an overgauge hole will provoke the generation of whirl. Continuous attempts to make technology improvements in RWD operations have been performed during the years. When an underreamer is incorporated in the drilling system it is highly important to look at all components included in the drillstring and their relation to each other, to abate detrimental vibrations and optimize the drilling performance. Adequate stabilization and proper BHA configuration can contribute to minimize the vibrations generated by the reamer.

5.1 Underreamer drilling leads to detrimental vibrations

5.1.1 Underreamer experience on Grane

Statoil performed sidetracking on a Grane well serving as a comparative example to demonstrate how underreamers affect the severity of shock and vibration. The first run (G-37) was performed in Oligocene sand. A 16”×17 ½” drilling BHA was used due to swelling green clay, with the intent of being able to POOH and avoid back reaming. After this run was performed and measurements were taken a sidetrack was drilled (G-37 T2), using a 17 1/2” BHA. The sidetrack was drilled at nearby locations under identical conditions, making this a perfect opportunity to assess how underreamers affect the vibration tendencies [15].

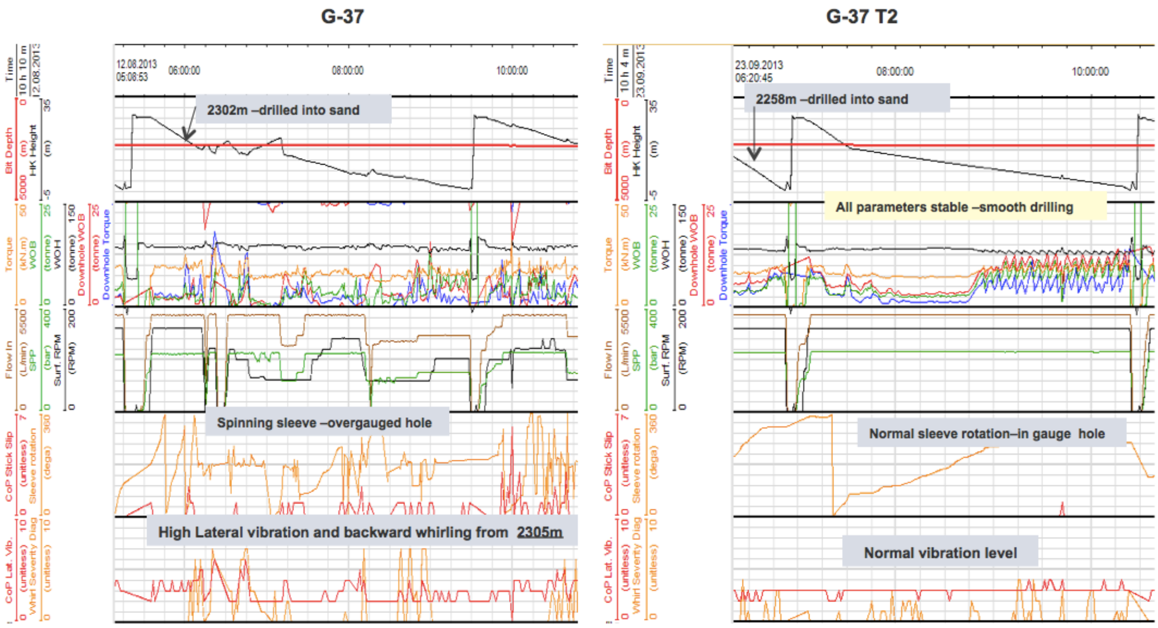

Figure 32: Vibration level with and without underreamer on Grane [15]

Figure 32 shows the recordings, including lateral vibration level, for the original hole with underreamer and for the sidetrack without underreamer. For the G-37 well with underreamer BHA, noticeably higher vibration peaks and average vibration level are recorded. From 2305m (7562ft), when drilling into sand, severe lateral vibrations and backwards whirl are recorded, resulting in high bending moment. The drilling parameters are altered to mitigate the vibrations without success. The ribs on the AutoTrak eventually failed, and tripping was performed, leading to NPT and increased expenditure. It is obvious that the underreamer has a derogatory impact on the vibration level. For the sidetrack, G-37 T2, the same section was drilled with high RPM, without an underreamer. When drilling into sand, torque and WOB stays stable, indicating smooth drilling conditions. As seen from the figure, the lateral vibration level is significantly reduced (normal level) and hence it was drilled successfully to planned depth. Consequently, the 17 1/2” drilling BHA is preferred, being less prone to vibrations and whirling, and thereby lowering the risk of tool failure and additional costs.

5.1.2 Underreamer experience in deviated wellbore

A second study is presented, to further demonstrate how underreamers excite drillstring vibrations. In this case study a BHA configuration with an 8 ½” PDC bit was used, together with an 8 ½" ×9 7/8” underreamer. In the first drilled section of the well the underreamer was inactive to quantify the difference in vibration level after the underreamer was activated. The vertical hole was drilled using two dynamic measuring tools (DMT), one above the bit and one above the reamer, to record the dynamics and loads of the bit and reamer [35].

The field test was initiated at a depth of 106m (348ft). Data were recorded to a bit depth of 152.5m (500ft), while the reamer was inactive. At this stage no significant static bending, but some drilling noise caused by the bit rock interaction, was recorded. The upper DMT placed near the reamer did not show any signs of damaging vibrations. 5m (16ft) below the first data measurements the reamer was activated and 5.25m (17ft) deeper, data were again recorded. Both datasets were collected at nearly identical conditions. Due to the cutting action of the reamer, the entire BHA now experienced high level of vibration compared to when the reamer was inactive. The cutting forces generated at the reamer initiated a motion in opposite direction of the string rotation (backward whirl). Lateral movement of the string was significantly increased at the DMT close to the reamer and higher vibration levels were also recorded at the lower DMT, close to the bit. The effects of the reaming process were less significant at the lower DMT compared to the upper DMT, however it was still present. The field test clearly demonstrated that the reamer contributed to significantly increased level of vibration, bending moment and accelerations [35].

A second test was performed in a deviated wellbore. This BHA configuration included a RSS for directional control. The string was bent due to the curvature of the wellbore and hence the string had constant contact with the borehole wall. As concluded in the vertical well test, the upper DMT experienced more vibrations than the lower. The stabilizers were subjected to higher contact forces in the deviated well due to the curvature. These contact forces prevented the reamer from going into backwards whirl, implying that the drillstring is less susceptible to lateral movement in a deviated wellbore compared to a vertical wellbore, as described in section 2.2.2 [35].

It is clearly demonstrated that underreamers induce cutting forces that are highly sensitive to lateral displacements. The side forces created by a reamer can attempt to generate backward whirl [35].

5.2 Bit and reamer aggressiveness

Various bit types have different aggressiveness, depending on the design. A bit is defined as aggressive when the bit cutters penetrate deep into the rock. DOC is a measure on how deep the bit cutters cut into the formation and is mainly controlled by WOB. An aggressive bit with more DOC will drill a larger part of the rock (figure 33) and thus more torque will be generated. By adjusting and monitoring the DOC, bit generated torque and vibrations can be controlled.

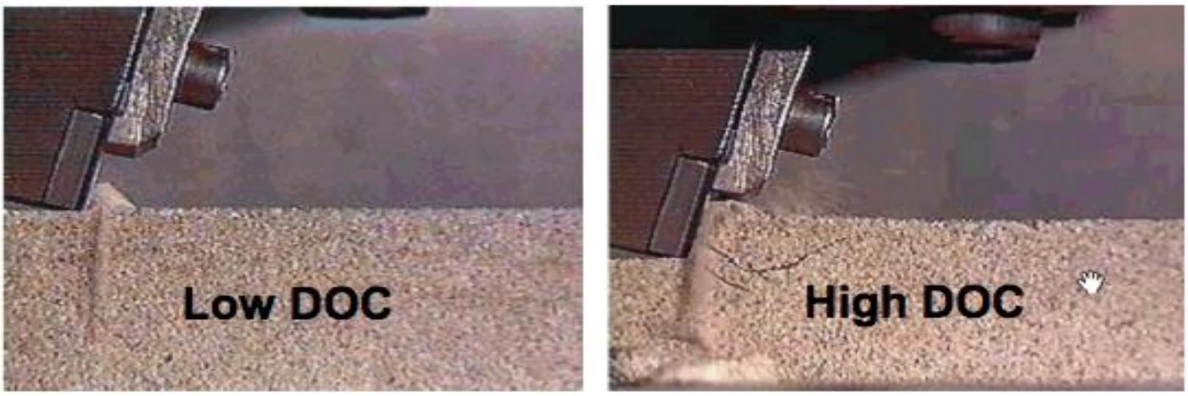

Figure 33: Depth of cut [36]

Drilling with an underreamer that is less aggressive than the bit will lead to increased side forces and hence the reamer should be designed to be more aggressive than the bit. By having a less aggressive bit, the bit will take a larger share of the downhole weight. As mentioned, the balance between the bit and the reamer is delicate and might switch if the bit hits a harder or softer formation. The weight distribution will change according to formation layering. To abate vibrations induced by the underreamer, it is highly important to control the aggressiveness and the interaction between the bit and the reamer. By properly regulating the DOC of the bit, a significant gain is seen in terms of reduced vibration levels. It is important to emphasize that regulating the DOC is essential in non-underreamer operations as well. Problems such as severe stick-slip due to aggressive PDC bits can occur without regulating the DOC.

5.2.1 Control bit aggressiveness with depth of cut control (DOCC)

The weight distribution on the bit and underreamer will to a large extent affect the vibration tendencies and hence it is highly important to match the weight and torque of the underreamer to the bit. DOCC can be implemented in the bit to obtain a less aggressive bit. DOCC is the principle of adding a bearing surface to the bit, engaging when the preferred DOC is achieved. The aggressiveness decreases when the bearing surface engages, as it carries weight. By limiting the DOC on the pilot bit when run in conjunction with the reamer, the cutter loads on both are more evenly balanced. A bit design with DOCC features, designed for a specific formation and matched to the reamer can therefore result in fewer and less aggressive vibration events, better weight distribution and higher ROP [34].

Different reamer suppliers have in recent years discovered this approach and various measures have been implemented to reduce the aggressiveness of the pilot bit. Such measures include using smaller cutters and/or more blades on the bit. This serves to the purpose of slowing down the bit, however it tends to have an adverse effect on the drilling speed [37].

5.2.2 Angle on bit cutters

Small adjustments can be made to the bit to control the aggressiveness. The angle of the cutters (back-rake angle) will affect the cutting tendencies. By using a bit with 90deg angle, relative to the formation, the bit will naturally cut the formation aggressively. By implementing a bit with smaller angle relative to the formation, gentler and less aggressive cutting will prevail. Consequently, a large part of the weight will be on the bit, reducing the side forces experienced by the underreamer and thereby reduce the risk of experiencing detrimental drillstring vibrations.

5.3 Placement of stabilizers

Proper stabilization is highly important in underreamer applications. However, choosing proper stabilization components above and below the RWD tools can be challenging. There is a common understanding in the industry that a stabilizer should be placed immediately below the reamer. By doing this the reamer is centralized in the pilot hole, the rock cutting action of the reamer is stabilized and the occurrence of damaging vibrations are reduced [37].

Previous vendor tests have indicated that a slightly undergauge stabilization pad directly below the cutting structure of the reamer reduces the vibrations seen while reaming and thus maintains the tool stability. To endure rough conditions and to function for a long time this stabilization pad should be made of hard-faced material [37]. When placing a stabilizer just below the underreamer it is highly important to be careful to avoid creating a choke in the annular flows.

5.4 Expandable concentric stabilizers

An on-going subject in underreamer applications is the difficulties related to stabilizing the BHA and the collars above the reamer in the enlarged hole section. A particularly big issue has been that conventional fixed stabilizers placed above the underreamer cannot have larger pass-through diameter than the restrictions above it. The industry must adhere to minimum pass through requirements on bit and reamer assemblies and thus they are most often run with undergauge stabilizers. With a pass-through stabilizer in the enlarged section of the borehole, the BHA is freer to move laterally in the wellbore and cause friction. The whirl friction becomes evident through the high WOB needed to maintain the ROP, increased MSE and more lateral vibrations [37].

The practice of using pass-through stabilizers in the enlarged borehole is most likely inducing BHA vibrations and subsequent damages, as the stabilizers cannot efficiently stabilize the upper BHA. In fact, some vendors have occasionally chosen to add additional stabilizers in order to supress lateral vibrations. Since the stabilizers most often are undergauge this can actually amplify the problem [37]. To reduce the challenges met when using an undergauge stabilizer above the underreamer, an innovative expandable stabilizer has been developed, to provide full rather than partial stabilization. This can be a beneficial alternative to ensure that the BHA is fully stabilized.

With a full gauge stabilizer (expandable stabilizer) placed above the underreamer several benefits can result, including [37]:

- Reduced whirl potential
- Reduction in lateral vibrations
- Reduced BHA damage
- More efficient drilling
- Economic advantages

5.4.1 Field validation

Field experiences are presented below to illustrate the effect of having an expandable stabilizer above the underreamer.

Pass-through-size stabilizer vs. concentric expandable stabilizer

Baker Hughes performed testing in two twin boreholes, one with a conventional pass-through stabilizer above the concentric reamer (Well 1) and the other with an expandable stabilizer above the reamer (Well 2), to determine the worth of using an expandable stabilizer. The BHAs used were otherwise identical and the detailed BHA designs are shown in figures 34 and 35. The bits used had DOCC to synchronize properly with the reamer (described in section 5.2.1). The objective in the test was to drill a 12 ¼" pilot hole and open it to 14 ¾". The formations of both wellbores were identical due to proximity, mostly consisting of shale. The maximum dogleg planned for the wells were 6deg/30m build and drop and the wellbore kicked off from vertical at 198m (650ft) depth, with a planned build from 0 to 30 degree inclination [37].

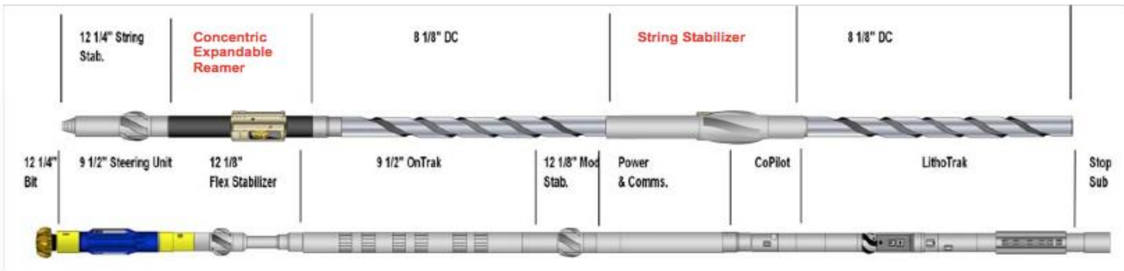

Figure 34: BHA 1, pass-through stabilizer above the reamer [37]

Figure 35: BHA 2, expandable stabilizer above the reamer [37]

The expandable stabilizer is usually placed 9-10m (30ft) above the reamer and is activated when required, to stabilize and centralize the BHA in the enlarged hole. When desired it may be closed and returned to surface. In this particular test the concentric stabilizer was created by replacing the sliding cutter blocks on the reamer with sliding stabilizer blocks, see figure 36. The expandable stabilizer had a few cutters on its upper end to backream if necessary [37]

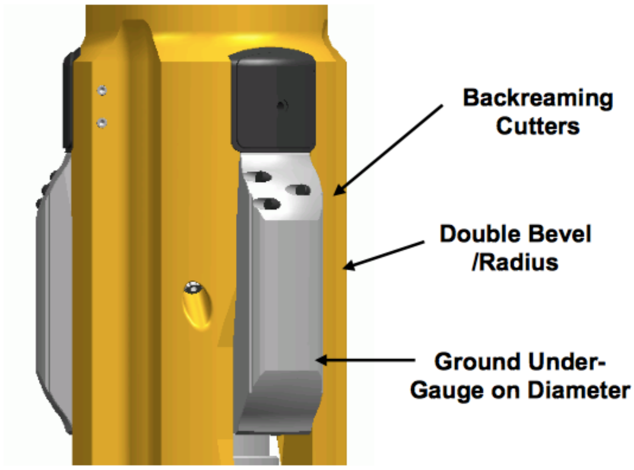

Figure 36: Expandable stabilizer and blade design [37]

To measure the dynamic responses of the BHA, sophisticated drilling mechanics and dynamics diagnostic tools were used. The ROP of the two wells were intentionally paralleled and it was confirmed that the ROP was closely tracked together. However, the WOB required to maintain the ROP was significantly less with the expandable stabilizer in use as compared to the conventional stabilizer. When using the expandable stabilizer above the reamer the ROP was increased with 29%

for a given WOB. In addition the MSE of Well 1 with pass-through stabilizer apparently experienced higher BHA or drillpipe friction, as the overall average MSE was 16% higher. Until the maximum inclination of 30deg was reached, and the hole began to drop angle, the expandable stabilizer actually had 34% lower MSE, meaning that the drilling efficiency was significantly improved. Most importantly, it was confirmed that the expandable stabilizer supressed damaging vibrations as intended. Below 20deg inclination the lateral vibration level averaged 26% lower. The drilling efficiency was clearly improved due to reduced buckling and whirl in the upper BHA and reduced frictional losses against the borehole wall [37].

An important finding was made in the test; when the well reached 30deg inclination and began to drop angle, the assembly with the expandable stabilizer actually required more WOB than with the conventional pass-through stabilizer in the BHA. At this point the drilling got less effective. In higher angle holes the BHA, collars and smaller stabilizer of Well 1 probably stabilized themselves on the side of the borehole and a full gauge stabilizer was not needed. In the inclined section (above 30deg inclination) the expandable stabilizer actually became a hindrance, causing more friction and increased MSE. It is not clear if this was due to the inclination or due to an inflection point in the borehole path [37].

It should be mentioned that the stabilizer blocks on the expandable stabilizer were slightly undergauge and had bevelled edges and radius. This feature is preferable compared to the sharp edge geometry seen on other expandable stabilizer products available on the marked, which actually can induce BHA whirl, as described in section 4.3. This could have contributed to the success [37].

Expandable stabilizer on Troll

Expandable, concentric reamers have been used to drill the 12 ¼”×13 ½” section of multilateral wells on the Troll field in the North Sea for the past several years. Underreamer drilling on Troll has introduced challenges when drilling through interbedded sands and hard calcite cemented stringers, and has led to high occurrence of detrimental vibrations. To improve the drilling efficiency in these operations Statoil and Baker Hughes tested the expandable reamer and expandable stabilizer, to determine the benefits of the technology. This was the first worldwide landing/horizontal application drilled with this technology.

Originally the tool was designed for use in the GoM, in low inclination or tangent sections. However, as the Troll field called for a directional, landing profile, an engineering design process to develop a fit-for-purpose reamer and stabilizer was initiated. In the configuration introduced to Troll, the stabilizer provided 1/8” undergauge stabilization above the underreamer when activated via drop-ball.

The patented stabilizer pad should provide full stabilization support without high levels of reactive torque [38].
The expandable stabilizer technology was tested on well 31/2 H-3 CY1H in 2009, with the objectives being to demonstrate the functionality of the reamer and stabilizer, and evaluate the ability of the stabilizer to reduce the vibration level, increase the ROP and decrease wear on the reamer cutter blades. Prior to introducing the expandable stabilizer, a series of technical challenges related to the stabilization of the BHA were observed. High levels of lateral and torsional vibrations, and downhole tool failures were frequently encountered and proved difficult to counter. 60% of all runs were run OOS [38].

Once the well had been drilled the reamer was determined to be in gauge with some worn cutters and chipped teeth. The landing section was drilled successfully to TD in one run and both the reamer and the expandable stabilizer worked as planned, with minimal tool wear. The lateral vibration level ranged from level 2 to 3, with occasional higher readings (within acceptable levels) and the stick-slip level was lower than the majority of Troll reamer runs. Average ROP was 17.8 m/hr (58.4ft/hr) and higher than target ROP 14 m/hr (45.9ft/hr), and significantly higher than the majority of prior 12 ¼”×13 ½” runs [38]. The success in this run demonstrates the benefits of introducing an expandable stabilizer in underreamer operations and makes this a preferred configuration for subsequent applications.

After the first run, three more runs were drilled with the same technology, comprising a “test programme performance” on Troll. A drilling performance comparison with other reamers was made, based on wells drilled in 2009 and 2010. The results are listed in table 10, were the wells drilled with other vendor reamers are defined as OV, while the runs drilled with the reamer and expandable stabilizer are referred to as SC. An average ROP of 11.8m/hr (38.7ft/hr) was achieved with other vendor reamers, whilst 13.8m/hr (42.3ft/hr) ROP was achieved using the reamer and expandable stabilizer. Consequently, an improvement of 17% was achieved with the expandable stabilizer. The technology proved to enhance the drilling performance in both dense (hard calcite) and less dense (loose soft sands) rocks.

Table 10: Comparison of alternative reamers with reamer and expandable stabilizer technology [38]

Year	Rig	Well	Reamer	Distance (m)	Hours (hrs)	Ave. ROP (m/hr)	Distance (m) density > 2.3-g/cc	% Density > 2.3-g/cc
2009	WV	31/2 F-6	OV	587.5	42.0	14.0	72.2	12.3 %
2009	WV	31/2 X-22	OV	485.0	36.6	13.3	53.7	11.1 %
2009	WV	31/5 H-3	SC	572.0	32.2	17.8	95.6	16.7 %
2009	ST	31/5 H-6	OV	410.0	29.4	13.9	78.0	19.0 %
2009	ST	31/2 M-24	OV	576.0	53.7	10.7	185.1	32.1 %
2009	ST	31/2 F-1	OV	475.0	62.3	7.6	107.8	22.7 %
2010	PP	31/5 I-21	OV	551.0	36.5	15.1	52.0	9.4 %
2010	PP	31/2 M-14	SC	671.0	50.0	13.4	89.2	13.3 %
2010	ST	31/2 O-26	SC	439.0	42.9	10.2	93.6	21.3 %
2010	ST	31/2 O-21	SC	524.0	35.1	14.9	126.2	24.1 %
Total				**5290.5**	**420.7**	**12.6**	**953.4**	**18.0 %**
Performance summary								
By Reamer (x6)			OV	3084.5	260.5	11.8	548.8	17.8 %
By Reamer (x4)			SC	2206.0	160.2	13.8	404.6	18.3 %

The following conclusions were made for the test programme wells [38]:

- High stick-slip and whirl was reduced
- Wear on reamer was improved
- Wear on equipment was improved
- Drilling ROP was improved
- The reamer was stabilized, enabling higher WOB and RPM to be applied and hence more energy was delivered to the bit and the reamer

The use of an expandable stabilizer demonstrates a preferable step in mitigating detrimental vibrations in underreamer operations.

Expandable stabilizers are to this date still used on Troll and considered to be a contributing factor to the success seen on this field. In figure 37, newer numbers (2009-2014) are presented for the effect of the expandable stabilizer. GaugePro is the trade name Baker Hughes uses on the expandable reamer, which is run in conjunction with the expandable stabilizer. The results show that with the expandable stabilizer technique the lateral vibration level is reduced by 21% and the stick-slip level is significantly reduced. In addition, the average ROP ranges higher and the ability to drill through hard formations is improved.

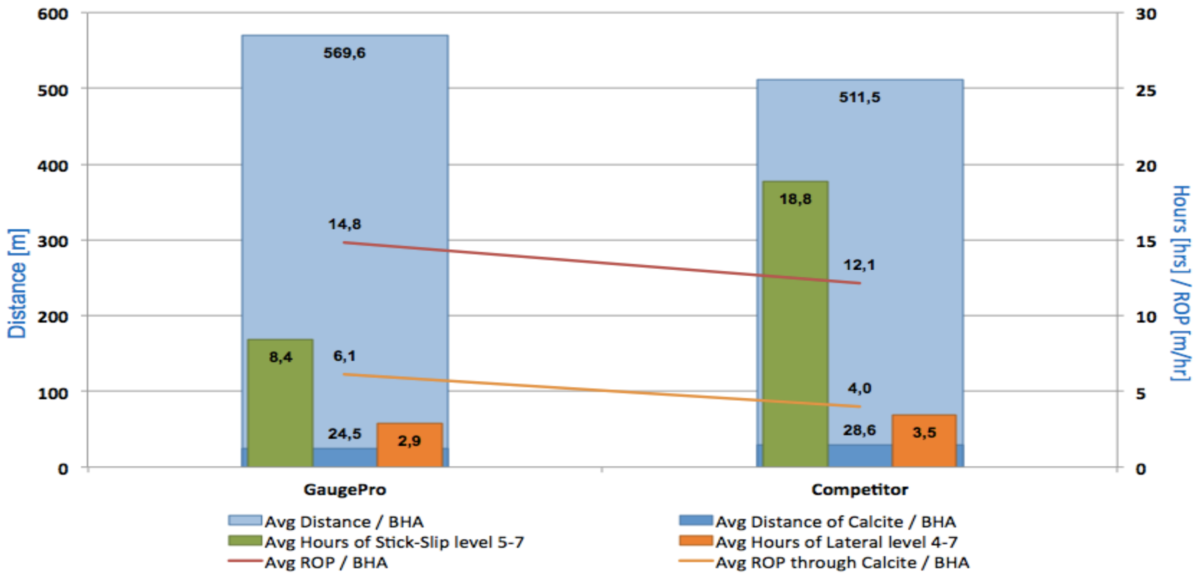

Figure 37: Performance comparison of expandable stabilizers on Troll (2009-2014) [39]

6. Supplier input on vibration mitigation

In this section the supplier´s experiences and operational procedures will be addressed. Through conversations with Frank Johsen in Baker Hughes, Egil Kristiansen in Halliburton and Richard Harmer in Schlumberger good procedures have been uncovered and improvement areas recognized. The opinions of the suppliers are essential when establishing effective vibration mitigation tools and techniques.

6.1 BHA design optimization software

BHA modeling software has been developed, enabling drilling engineers to design vibration resistant BHAs. These models can be applied to configurations with the majority of common components, in all hole sections. For field use, BHA modeling can be utilized to predict optimum operating ranges for RPM and WOB and/or to compare the dynamic response of alternative BHA configurations.

6.1.1 BHASYS pro (Baker Hughes)

For advanced BHA modelling Baker Hughes relies on BHASYS pro, analysis software for BHA modelling and static calculations. The software is based on finite element analysis and the use and implementation requires thorough application engineering knowledge. BHASYS pro has several attributes, including:

- Analyses the deflections and static loads along the BHA
- Optimizes the stabilizer placement
- Provides build up rate predictions
- BHA sag verification

The objective of the software is to optimize the BHA and thereby enable it to withstand vibrations and prevent damaged tools, twist-offs and hence NPT [40].

Dogleg, inclination, azimuth, WOB and mud weight are the main input variables. Each BHA is designed to fit the client needs and the wellbore trajectory, hence the bending moment distribution for each assembly is analysed. Pre-drilling, the magnitudes of the bending moment at various locations along the BHA are compared, to determine which configuration that is preferable. The bending moments are compared to the established limitations on connections and components, and Baker Hughes design BHAs to stay below the critical limits. The BHAs are designed so they can take at least 1deg/30m DLS more in build/drop/turn compared to the DLS in the planned trajectory, before any of the BHA components/connections goes OOS [41]. This allows sufficient capability for both static and dynamic induced bending moments without considerable damage. Stabilizers and various components are moved around within the assembly to obtain an optimum BHA configuration for the operation in store. In addition it allows the supplier to predict the optimum range of drilling parameters.

Pre-drilling, the supplier spends a lot of time and resources on optimizing the BHA design. Baker Hughes employees continuously work with BHASYS pro to provide a vibration resistant BHA. A BHA performance report is made for each assembly used and the BHA modelling results are stored in databases, making it possible to assess the BHA performance post-drilling. After the assembly has been used, negative experiences are reviewed and taken into consideration in similar operations. A potential improvement area lies here, as BHAs that have proven successful in prohibiting detrimental vibrations might be given insufficient attention. By reviewing assemblies behind good results, effective measures can be established and future operations can be streamlined to ensure optimum drilling performance.

Baker Hughes engineers have moved away from dynamic modelling and rely on static modelling in their attempt to design a vibration resistant BHA. The goal is to provide a statically stable drilling assembly. The drilling service operations manager stated that dynamic modelling results in incorrect sizes and measurements. A dynamic model based on mathematical measurements has unrealistic assumptions, such as in gauge hole, constant bit weight and constant RPM and hence can result in large errors, as these parameters will change continuously during drilling. A static model will according to Baker Hughes lead to closer alignment between predicted behaviour and field experience [41].

6.1.2 I-Drill (Schlumberger)

Schlumberger uses dynamic modelling to select optimum BHA configuration and bit. The company does extensive work to optimize the BHA design in order to prohibit detrimental vibrations. The process of designing an optimal BHA configuration is based on several analysing systems, including; IDEAS (integrated drill bit design forum), I-Drill (engineered drilling system design) and DBOS (drill bit optimization system).

I-Drill engineers rely on IDEAS, which was first used by Smith as a bit design tool, to provide bits inducing minimal vibrations. However, the software has gotten a broader usage area, optimizing the entire BHA. IDEAS relies on advanced modelling to optimize bit performance and takes several factors into account; the rock-cutter interface, the drillstring, the drive system, BHA components, drilling parameters, interaction between elements and the total system on bit behaviour in dynamic drilling environments. The main purpose is to provide dynamically stable bits, leading to more efficient drilling and less stress on the BHA. Laboratory tests and simulations are performed to determine cutter forces [42].

I-Drill is occasionally used to configure the BHA and provides 4D simulations of the drill string. This software is typically used in the planning phase, providing BHA and parameter recommendations to minimize the vibration tendencies. Schlumberger claims that I-Drill is the most advanced dynamic drill system software on the marked, providing highly vivid outputs [43]. The bit and each component in the BHA and drillstring are simulated in I-Drill. Alternative configurations are evaluated and considered. Various drill bit options, BHA components, designs, drilling parameters and placements are analysed. Advanced graphics capability illustrates the results clearly. The dynamics of the drillstring is evaluated through various formations with different strength, inclination and homogeneity, making it possible to predict the performance through interbedded formations. Offset well data is used as reference to predict the conditions the specific assembly is designed for [42].

I-Drill claimed benefits [42]:

- Eliminates trips to change the BHA
- Predicts bit performance
- Predicts dynamic behaviour of BHAs
- Identifies weak spots in the drillstring to avoid lost tools
- Reduces axial, torsional and lateral vibration, providing a dynamically stable assembly
- Provides balanced drill bit and underreamer cutting structure loading
- Enables improved drilling programs with less risk of NPT

A unique feature with I-Drill is that it enables modelling of the cutting structures. Schlumberger possesses a database containing 100 different rock formation types, making it possible to simulate the conditions in the well accurately. DBOS is used to predict the hardness of the rock, to select the proper rock to use in the simulations. The best match to the field lithology, based on the compressive strength of the rock, is selected. The cutters are scraped and tested on the rock, measuring the DOC and forces exerted on the bit. The cutting structure is evaluated and simulated in 4D. The software is also capable of modelling the cutting structure of the underreamer, making it possible to predict the interaction between the bit and the reamer, even through interbedded formations [43]. This will consequently contribute to enhance underreaming operations.

The negative features with I-Drill are that only Smith bits can be evaluated and the simulation process is time consuming. It can take up to a day to simulate a small section of the well. As a consequence, I-Drill is mainly applied in complex operations such as; underreamer operations, exploration wells,

wells with little field experience and when a new BHA design is implemented. Only the most interesting sections and cases are simulated.

Schlumberger is the only directional supplier that solely offers a dynamic model to optimize the BHA design, with the possibility of static modelling if desired. Schlumberger claims that dynamic modelling improves the accuracy. Without taking the dynamics into account underestimated bending moments can result. A dynamic model makes it possible to predict both the average bending moments and the peaks. Variation tendencies are better illustrated and hence model results are closely aligned with field experience [44].

6.1.3 MaxBHA (Halliburton)

Halliburton actively utilizes MaxBHA software to design drilling assemblies to meet the directional requirements in difficult 3D wells, in soft formations and in high dogleg wells. The software is used to provide an optimally designed BHA to maximize the steerability and minimize vibrations.

Claimed benefits [45]:

- Helps configure the BHA to drill the optimal wellpath, while reducing the NPT and increasing the ROP
- Improves downhole tool reliability by minimizing torque, drag and bending stress
- Corrects for axis misalignment between the BHA and the wellbore and thereby improves the directional survey data accuracy
- Performs critical speed analysis of BHA to identify the fundamental resonant frequency and its harmonics
- Performs mode shape analysis to determine the bending of BHA components when vibrations are introduced
- Assists in bit and reamer designs
- Allows for post-run analysis that can be used in future operations

MaxBHA offers both static and dynamic models. The static model is used to predict the dogleg severity capability of the BHA, to calculate the forces exerted on the bit and stabilizers, to gauge the formation effect to the BHA performance and to project the BHA behavior. The dynamic model can be used to perform whirl analysis for a specific set of well data and displays the critical speeds and their model shapes. In addition it can be used to study the effect of various input parameters, such as WOB, hole size or inclination [45]. By utilizing this software the critical speeds can be avoided, preventing harmful resonant vibrations

The modeling software can model complex BHA configurations and comprises a multi-hole model for RWD application, potentially improving underreamer operations. It should also be mentioned that the software has real-time modeling capability. A specific merit with this software is that Halliburton claims that it is considerably faster than other methods, modeling complex BHA and well configurations in less than one-half second. The software is flexible, fast and simple and thereby enables modeling to optimize directional drilling at all times [45]. It is a global internal requirement in Halliburton that each drilling assembly must be modeled in MaxBHA. This is a positive finding, as small changes in the assembly can have large consequences in terms of drilling dynamics.

MaxBHA has some limitations and does not seem to be as advanced as I-Drill. The cutting structures cannot be modeled in this software and the interaction between the bit and underreamer is not analyzed. In addition, the software is extremely fast in comparison to I-Drill and hence questions can be asked to whether or not it is as accurate as other software.

6.2 Stabilizer design and placement

Stabilizer design and placement varies for each directional supplier according to operation. The BHA optimization software is often used to predict the optimum placement, span length and size of the stabilizers. However, the directional suppliers have some standard procedures to optimize the stabilization.

A main goal for Baker Hughes is to provide equal force distribution on all stabilizers. The stabilizers are evenly distributed within the assembly to prohibit excess wear on any components. The rule of thumb for the company is that the distance between each stabilizer should not be more than 10m (33ft) or less than 3m (10ft), depending on well path and tools [41]. The maximum span length has been established to avoid long distances of free pipe, which increases the occurrence of vibrations.

The design features of stabilizers are highly important, as the blade design affect the genesis of vibrations. In high inclination wells much force is exerted on the stabilizers and thus sharp edges on this component can lead to great challenges. The directional suppliers recognize the possible challenges caused by sharp edges on stabilizers and provide some tools with bevelled edges. However, large stabilizers with sharp edge geometry are still used. Frank Johnsen in Baker Hughes stated that; as long as the assembly is not rotated over the same area for a long period, sharp edges are not viewed as a problem nor treated [41]. Schlumberger has experienced problems with straight bladed stabilizers in the past and relies on stabilization design guidelines were side cutting and other features are specified. However, lateral cutting aggressiveness is not exclusively described in these guidelines. To further optimize the geometry Schlumberger utilize I-Drill and IDEAS [44].

6.3 Tapered stabilization in large hole sections

In large hole sections, such as the 17 ½" section, Statoil has experienced a higher number of twist-offs and lost in hole incidents compared to smaller hole sections. A problem possibly increasing the twist-off tendencies is that some suppliers utilize close to full-gauge stabilizers without gradually downsizing the stabilizers upwards in the assembly, shown in figure 38. The area directly above the top stabilizer will consequently be vulnerable for vibrations and potentially twist-offs. This problem is mainly confined to large hole sizes due to the freedom of movement and the large masses present. The BHA is subject to substantial lateral displacement if undesirable movement occurs. Tendencies of drillstring breakage in the area just above the top stabilizer are often seen, as this area will experience high bending moments, in addition to vibrations. The reason for twist-offs is difficult to identify as they occur high up, where there are no shock/vibration sensors. The root cause is often inconclusive and poor connections or defected steel is suspected. However, the real source leading to problems is most probably vibrations, as the drillstring in the area immediately above the stabilizers are susceptible to large bending moment and vibrations.

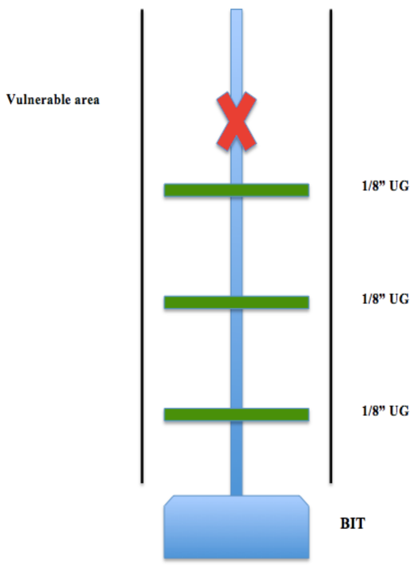

Figure 38: Standard stabilizer distribution in large hole sections

For these sections the BHA- and stabilization configuration varies for the directional suppliers. Baker Hughes acknowledges the tendency of drillstring vibrations and high bending moments, causing twist-offs in the area immediately above the top stabilizer. To reduce the forces exerted on the string and prevent this problem from occurring, tapered stabilization has been implemented. This has worked as a standard for Baker Hughes since 2008 [41]. Tapered stabilization is the principle of implementing stabilizers in the BHA where the blade OD decreases with distance from bit, making the assembly more balanced and more resistant to vibrations. The tapered stabilization technique allows the string to gradually shift from the centerline of the hole at the bit, to the low side of the hole in the upper BHA (figure 39). This technique will distribute the side loading better, decrease the local bending spikes and increase the reliability of the tools. Prior to implementing tapered stabilization, Baker Hughes could report that several assemblies were lost in hole in the North Sea.

Figure 39: Tapered stabilization [40]

Standard procedure for most drilling suppliers is to use tapered collars. A principle of steady transition of drill collars, by gradually downsizing the collars upwards in the assembly. The procedure is application dependant and the intent is to reduce the bending moment.

6.3.1 Calculation example with tapered stabilization on Volve

An AutoTrak BHA with tapered stabilization was recently used in the 17 ½" section on the Statoil operated Volve field. Baker Hughes was the main contractor. The tapered BHA was utilized to prevent vibration-induced twist-offs in the area above the stabilizers and to reduce the overall bending moment in the BHA. The well plan required 3.0deg/30m DLS, mainly build and turn, and the BHA configuration was designed so it could take at least 1.0deg/30m more than the well plan required [40]. BHASYS pro simulations are shown below to demonstrate that the technique serves to its purpose, decreasing the bending moment in the area above the top stabilization element.

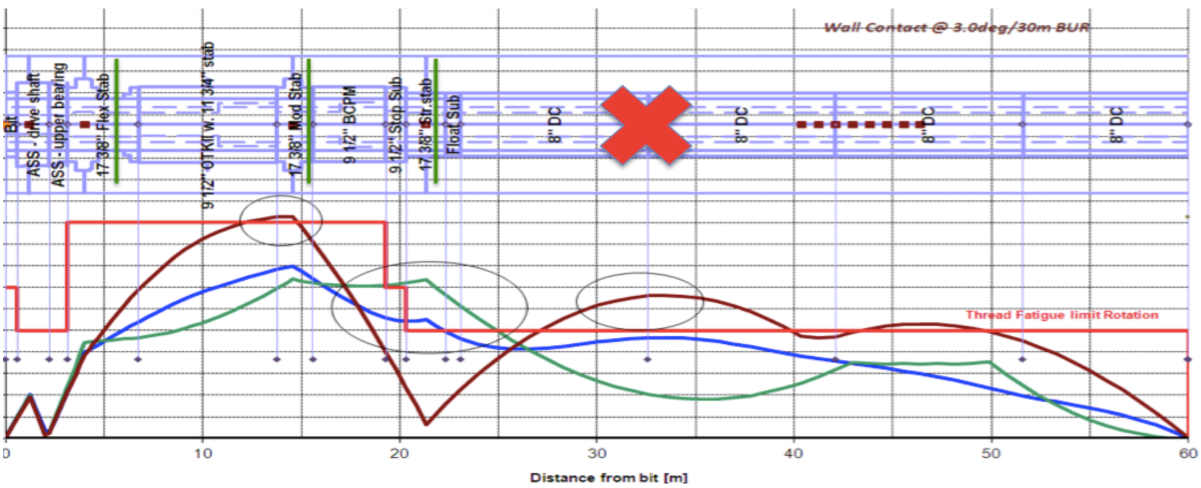

Figure 40: Bending moment distribution (Y-axis) without tapered stabilization [40]

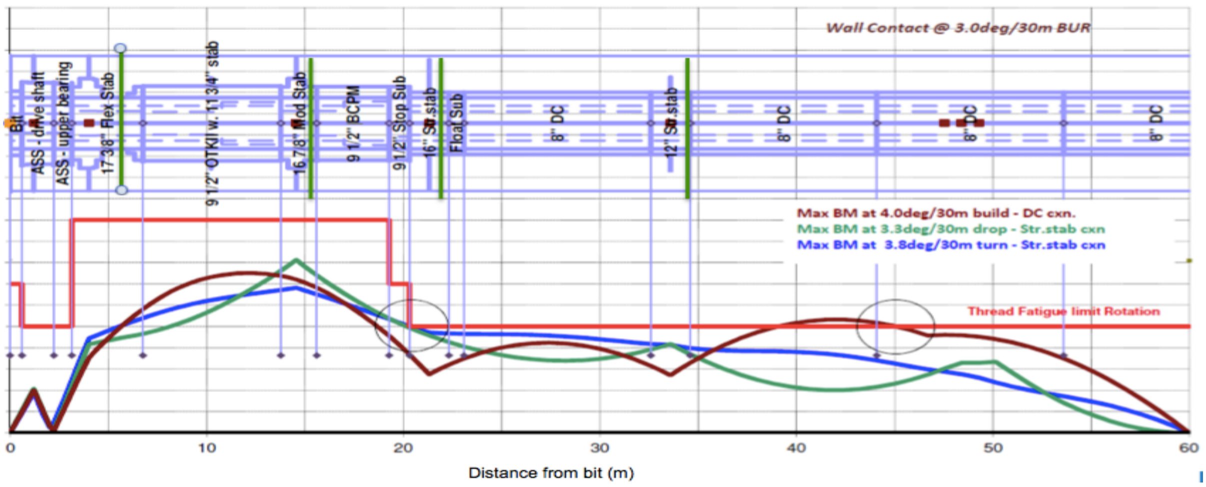

Figure 41: Bending moment distribution (Y-axis) with tapered stabilization [40]

Figures 40 and 41, illustrates the bending moment distribution along AutoTrak BHAs, with and without tapered stabilization. The two BHAs are otherwise identical. Maximum bending moment for the following build, drop and turn scenarios are simulated; 4.0deg/30m build (red), 3.3deg/30m drop (green) and 3.8deg/30m turn (blue). In figure 40, three stabilizers of the same size (17 3/8") are distributed within the assembly, without downscaling the stabilizer size. The BHASYS pro simulations shows significantly increased bending moment when this configuration is used, particularly in the area above the stabilizers. With the same DLS input, without tapered BHA, one can observe that the bending moment generated by the curvature will exceed the limits for the BHA components, potentially leading to tool failure or twist-off. Referring to figure 41, the BHA with tapered stabilization (respectively 17 3/8", 16 7/8", 16" and 12") shows significantly lower bending moment, particularly in the vulnerable area discussed. The bending moments never exceed the established fatigue limit of the components and connections.

6.4 Use of the Anti Stick-slip Technology

AST has been used on several fields and both service companies and operators have driven its implementation. Statoil´s directional suppliers, Schlumberger, Baker Hughes and Halliburton have implemented AST, both in underreamer BHAs and without underreamers incorporated.

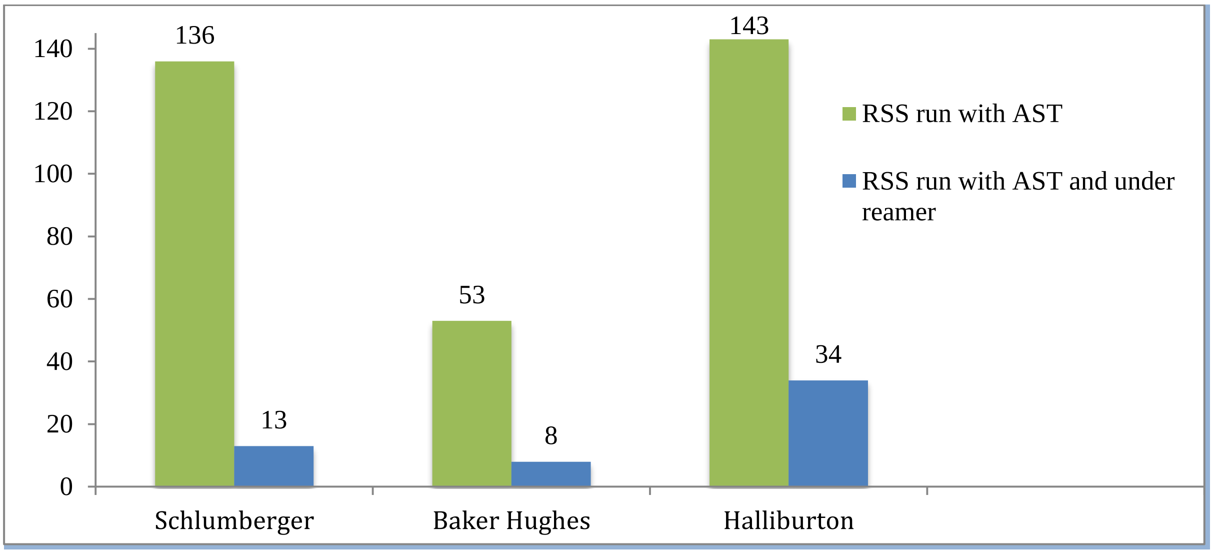

Figure 42: Number of AST runs for the different suppliers (-2012) [19]

Baker Hughes has utilized AST in several operations. However, as seen in figure 42, the directional supplier is by far the one using AST the least, exhuming most scepticism. Through conversations with Statoil and the different suppliers it became clear that the perception of the tool was dual. Baker Hughes stated that the tool might be beneficial in some circumstances, but that they were hesitant to use AST, as they have not been able to adequately quantify the effect [41]. Baker Hughes has been reluctant to utilize the tool mainly due to lack of documented effect. In addition, the supplier utilize the CoPilot tool in the BHA to measure real-time downhole vibrations, torque and WOB, giving them good overview and control of the downhole situation. The other directional suppliers have similar tools, but the CoPilot has been in use much longer, which might have given Baker Hughes an edge over the other suppliers. Use of CoPilot might reduce the necessity for Baker Hughes to implement optimization tools compared to their competitors.

Halliburton and Schlumberger seem overall more positive to the implementation of the tool. In collaboration with Statoil, Schlumberger has made reports confirming that the tool abate vibrations, particularly stick-slip. Richard Harmer in Schlumberger stated that the principle of AST is solid. If stick-slip is generated by the rock-bit interaction the tool may serve to its purpose, limiting the torsional vibrations from the bit. However, if the excitation source is the interaction between the drillstring and the borehole in long horizontal wells, AST is believed to have diminished effect. Schlumberger has mostly used AST in North Sea operations and hence questions can be asked to whether or not Schlumberger employees on a world basis are of the same opinion. Although the physics of the tool is logical, Schlumberger has also experienced difficulties in quantifying the effect for each operation, as several variables affect the drilling performance. The tool will not cure the problem or guarantee that stick-slip will be eradicated. Fully developed stick-slip has been experienced when the AST tool has been incorporated in the assembly. In addition, it was stated that the impact of the different configurations of the tool (spring stiffness and weight below the tool) has not been properly evaluated. For AST to be cost effective it should reduce the impact of torsional excitations and prevent the system from going into fully developed stick-slip [44]. The tool needs to be further analysed to evaluate its impact. Although Halliburton and Schlumberger is more willing to implement the tool, pros and cons must be weighed against each other and critical questions must be raised

6.5 Use of Frank´s HI tool

Baker Hughes has only used Frank´s HI tool on a few selected wells, as the tool is relatively new on the marked. However, they are convinced that this tool can lead to several enhancements in the future. In particular, when used in underreamer operations, allowing the underreamer to move more freely, without damaging effects. It is believed that the tool can prohibit underreamer vibrations from affecting the BHA and bit [41].

Halliburton seem positive towards implementing the HI tool and Egil Kristiansen stated that the HI tool appears to be an effective measure to abate detrimental vibrations. Halliburton has also run the tool near the bit, where the vibration dampening effect is greatest. It was stated; “Halliburton utilizes point the bit technology and hence the placement has less affect to the directional control. With push the bit technology, the directional control is more likely put at risk”. Halliburton has run the HI tool beneath the Geo-Pilot with good results. However, the reduction in dogleg capacity has to be assessed prior to use [46].

Schlumberger has little experience with the HI tool and are hesitant to place components close to the bit. Although placing the HI tool directly above the bit may reduce the transmission, the supplier is extremely reluctant to place any components below the RSS, as the trajectory control is put at risk. Adding 1.2m (4ft) of additional length to the assembly just above the bit will change the contact points and possibly impact the directional response of the assembly. When placing the tool elsewhere, e.g. mid BHA, Schlumberger struggles to see the value of the tool. In this sense, Schlumberger is more positive to the AST tool, as it can be placed higher up in the assembly and still maintain its functionality [44].

6.6 Mitigating underreamer vibrations

Baker Hughes, Halliburton and Schlumberger have recorded severe vibration tendencies when utilizing underreamers, and various techniques and tools have been implemented to abate shock and vibration.

6.6.1 Expandable stabilizer above the underreamer (Baker Hughes)

As described in section 5.4, placing an expandable stabilizer above the underreamer is an effective technique to stabilize the enlarged hole section and potentially minimize shock and vibrations. Baker Hughes introduced expandable stabilizers in 2010 and is the only Statoil supplier using this technique, mainly in 12 1/4x13 ½" sections. Immediately after implementing the expandable stabilizers, Baker Hughes could report great results, as the vibration tendencies were reduced and the ROP increased.

BHASYS pro analysis on expandable stabilizer

The effects of using an expandable stabilizer above the underreamer can best be illustrated by reviewing the contact forces with and without an expandable stabilizer in BHAYS pro. In this example BHASYS pro simulations for a 12 1/4"×13 ½" BHA are presented.

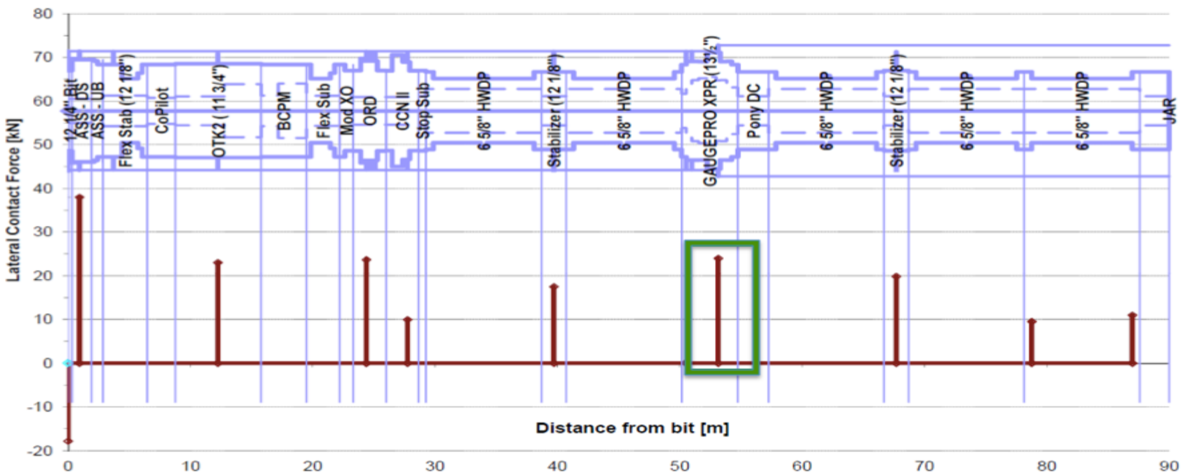

Figure 43: Contact force distribution along BHA with undergauge stabilizer [40]

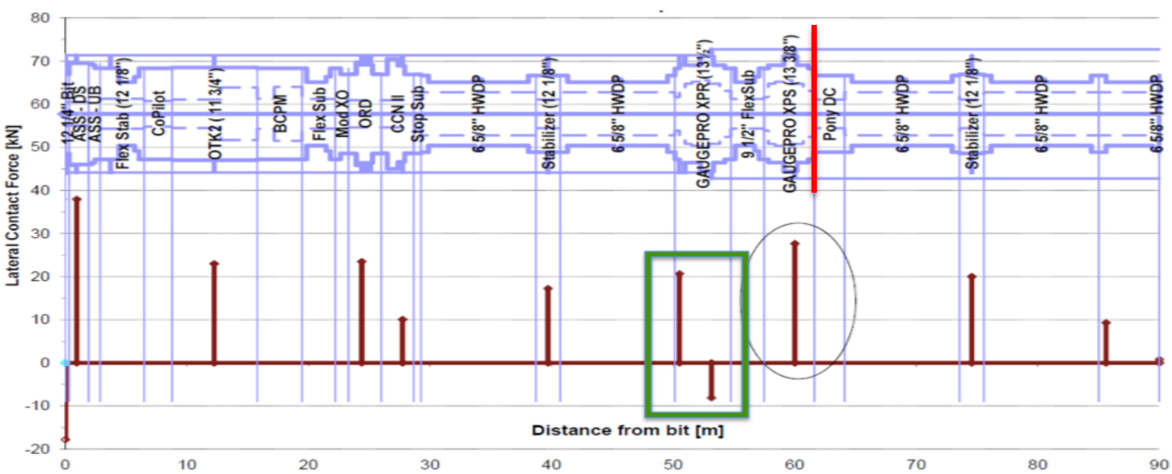

Figure 44: Contact force distribution along BHA with expandable stabilizer [40]

The calculations shown in figures 43 and 44 clearly indicate that the contact force exerted on the reamer is significantly reduced when the expandable stabilizer is placed above the reamer. A larger part of the contact force will be on the stabilizer, giving the underreamer less room to vibrate. This will result in increased drilling efficiency, providing increased ROP for a given WOB.

Schlumberger and Halliburton recognizes the benefits of using an expandable stabilizer above the underreamer to provide proper stabilization in the enlarged borehole. However, the suppliers rarely implement this technique. Although expandable stabilizers may be ideal, this is a costly procedure. Both Halliburton and Schlumberger strive to decrease the bending moment by placing an undergauge stabilizer above the underreamer. Schlumberger also utilizes the Rhino reamer, which can be forced to act as a stabilizer, to establish proper stabilization [44]. As described in section 5.4, undergauge stabilizers do not stabilize the drillstring in the larger diameter hole and hence problems might arise. If an expandable stabilizer can reduce the number of vibration related failures, the trade-off in terms of costs will have been worth it.

6.6.2 Interaction between bit and underreamer in I-Drill

To reduce the vibration challenges encountered when using underreamers, Schlumberger mainly relies on I-Drill. This advanced software enables the supplier to predict the interaction between the bit and the underreamer and how this will degenerate in the specific operation. The reamer performance is monitored and interaction with the bit is recorded, making it possible to adjust parameters and initiate preventive actions. I-Drill is used to prevent an aggressive bit from out drilling the reamer, by modelling the cutting structure of both bit and reamer. The cutting structure can be modelled in different formations to identify tolerable loads expected on the reamer [44]. Neither Baker Hughes nor Halliburton performs simulations to control and monitor the aggressiveness of the bit.

6.7 Problems in the 17 ½” section, Hordaland sand

A specific vibration related issue encountered in the 17 ½” section is loose sands. Statoil and the directional suppliers have for several years experienced high bending moments and detrimental shock and vibration in the Hordaland sands. These sections are mainly composed of loose unconsolidated sand and clay. Problems arise when the bit and BHA are in the loose sand section where washed out formations, detrimental vibrations and decreased ROP are experienced. It is often assumed by the suppliers that the challenges met are caused by hard formations. However, the real problem is not related to stringers, but rather unconsolidated sands leading to hole enlargements and unstable BHAs. Proper counteractive actions must be established to reduce this problem in the future.

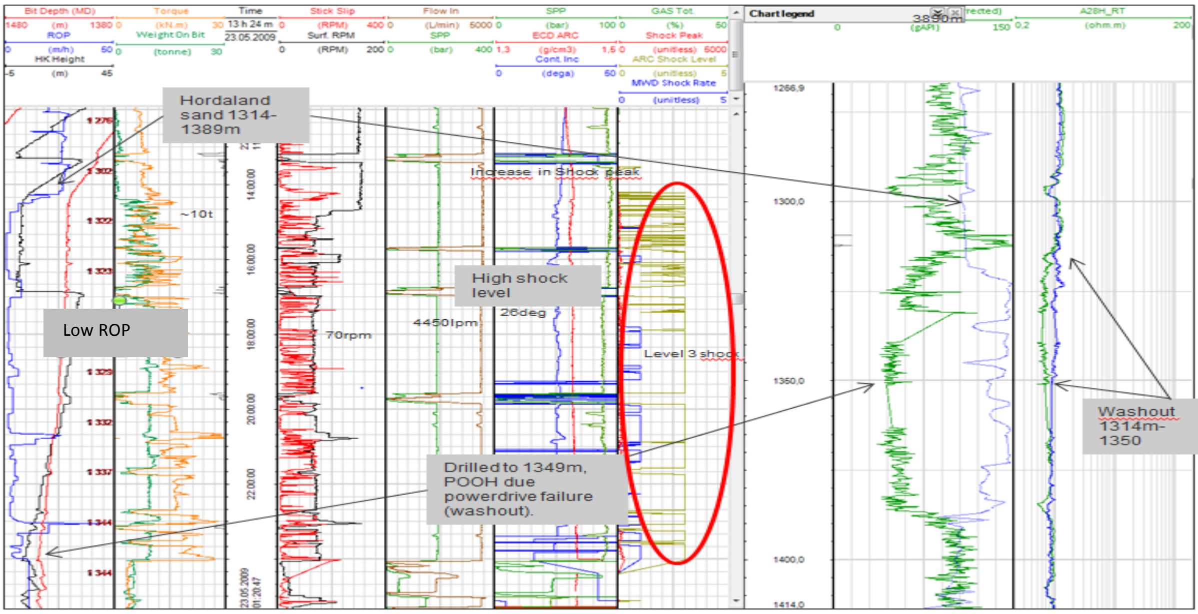

Figure 45: Hordaland sand log [47]

The recordings in figure 45 are made with a PDC bit, and clearly show that immediately after entering the Hordaland formation, at 1314m (4311ft), the bit/BHA creates washouts. As the first stabilizer enters the sand the ROP is gradually decreasing. At 1314m a small increase in torque and stick-slip is also recorded, indicating that it is drilled into loose sand. Towards the end of the run, torque and stick-slip level decreases while the shock level has significantly increased.

Control the RPM (Baker Hughes)

It is possible that the RPM used in these sand sections is kept too high. High RPM means that the bit drills aggressively and digs deeper into the formation. As the Hordaland sands are comprised of unconsolidated sands, the bit and BHA components create an enlarged hole and drillstring vibrations are initiated. If the drillteam keeps drilling with high RPM in this section, the BHA will move freely, touching the wellbore wall and potentially cause considerable damage. Clay is a more compact formation leading to a more in gauge hole and thus prohibits the BHA from moving laterally. In the clay section the BHA will be stabilized and thus higher RPM is tolerable.

Baker Hughes recommends dropping the RPM to 40-60RPM when entering unconsolidated sands, to achieve an in gauge hole. It is important that this is initiated before the hole is enlarged. Reducing the RPM has been attempted several times in the past, but has often been disrupted too early due to lacking results. An important factor to address is that the RPM must be kept low sufficiently long, giving the stabilizers time to move into the clay section, until stabilized. If the RPM is increased too early, the vibration level will stay high. Baker Hughes has implemented this technique successfully.

Grane was highly troubled with vibrations when entering the loose sand sections and the directional supplier experienced three tools breaking in two days. The described technique was implemented and visible changes in the vibration tendencies were recorded, as less energy in the drillstring allowed less vibration to develop. Baker Hughes has spent time and resources on training employees on this subject and the hazard is always addressed in pre-section meetings. As a result of these adjustments, Baker Hughes claims to have had fewer problems in the 17 ½" Hordaland sand section in recent years [41].

Problems have arisen offshore in this section when stick-slip has been generated. The standard procedure to mitigate stick-slip is to increase the RPM and decrease the WOB. Raising the RPM in loose sands will only contribute to worsen the vibration level, as lateral vibrations are more likely to occur.

Large parts of the petroleum industry have not implemented this technique, as it is difficult to get acceptance from the operator to lower the RPM sufficiently. Low RPM values are often not condoned, as it might compromise the hole cleaning. In loose sand sections, the challenges met due to vibrations should be weighed against hole cleaning issues. Proper hole cleaning should not be a problem in this formation, as the flow should be able to sufficiently clean the hole, due to small particles that are easy to flush out. The RPM is of less significance in near vertical wells and the operation can most likely sustain low RPM and still have adequate hole cleaning. The costs associated with low RPM are usually less significant than the costs incurred by tripping and damaged equipment. Particularly Halliburton experiences struggles in this section and this technique can prove valuable.

Bit selection and DOCC

Another potential solution to this problem is related to bit design. When drilling with an aggressive PDC bit, DOC awareness has proven valuable in the unconsolidated sand sections. DOCC regulates the aggressiveness of the bit and prohibits it from generating a larger diameter hole. Good results have been recorded at Statfjord and Snorre with this technique.

Kymera bits combine shearing from PDC fixed cutters and crushing cutting mechanism from roller cones, potentially providing better stability and smoother runs with minimal vibrations. As the Kymera drill bit leverages the cutting superiority of PDC bits in soft formations together with the rock-cutting strength and stability of RC bits in harder formations, it might be excelling in troublesome formations for PDC and RC bits, such as interbedded soft formations. Statoil has good experiences with the Kymera bit in the discussed section. This bit type was recently used on Grane (G-19A) and great results were recorded. The RPM was kept relatively high (100-120RPM) and it was drilled successfully to TD with 30m/hr (98.45ft/hr). Although the Kymera bit has had good record on fields like Grane and Gullfaks South, it has some limitations. This bit type has less durability and is an expensive choice compared to PDC bits with DOCC [47].

6.8 Troll progress

Troll is a field worth mentioning in terms of good procedures and great results. Baker Hughes signed a new contract with Statoil 01.09.2012, and since then continuous advancements have been made. The new contract is based on a ”Total delivery model”, giving Baker Hughes full responsibility for selecting optimal BHA design, bit and drilling parameters. The contract includes a bonus scheme per run, which rewards efficient runs and no failure of BHA components. Through collaboration with Statoil the best solutions are selected. This working method has been a large contributor to the success seen on Troll in recent years, as it has pushed the company towards new and smart thinking. The new contract has made it easier for Baker Hughes to control the operations fully and progress has been made in terms of more efficient drilling. “Total delivery model” contracts will be used in the future.

After the implementation of the new contract, reduced vibration tendencies have also been recorded on Troll. Baker Hughes states that these positive results are directly correlated to the new contract, enabling them to select drilling parameters during the operation, as well as selecting the bit and BHA configuration they assess to be best. After the implementation of the new contract, the BHA has been modified and some specific changes have been made to the bit to decrease the vibration tendencies.

The new drill bit design employed in the reservoir, in addition to better procedures and reinforced components, have resulted in higher ROP and lower vibration level on Troll the last 2-3 years (see figure 46). In fact, the last six months (late June to end December 2013) no trips have been required on Troll due to equipment failure, neither trips for bit related reasons (dull bit, damage on bit, worn down bit etc.) for 2013 as a whole. The talon technology is advanced mechanical and hydraulic bit designs, including uniquely shaped and positioned blades and nozzles, application specific bit profiles and low torque gauge designs. The improved efficiency designs potentially provides more energy for rock removal, less vibration and increased durability, all factors increasing the ROP [39].

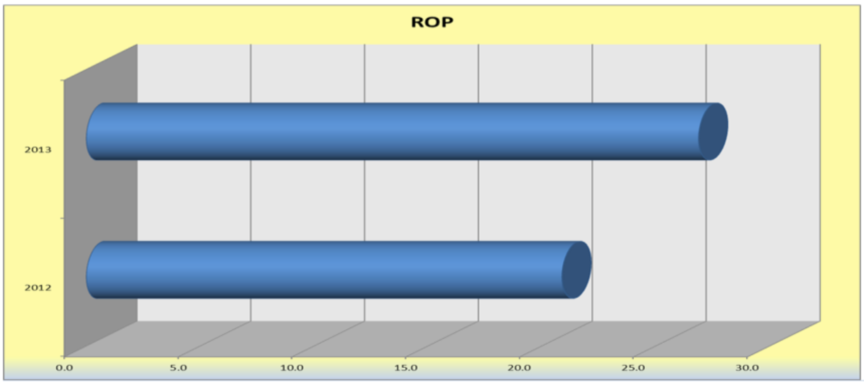

Figure 46: ROP improvements after new contract on Troll [48]

7. AST performance analysis

7.1 Introduction:

In order to quantify the effect of the AST tool a set of drilled wells in the North Sea have been analysed. The objectives were to gather data and determine whether or not AST has a positive impact on the drilling progress (ROP), as claimed by Tomax.

As highlighted in this thesis there are several factors that will affect the vibration level and the drilling progress, including:

- Rotational speed
- WOB
- Formation type
- The configurations and components in the drillstring
- Bit type
- Well geometry

If these parameters vary from one well to the other, this could potentially affect the ROP. Consequently, the findings in this analysis are only indicatives on the effect of AST, rather than scientific proof. Several factors could potentially affect the drilling progress and these are not considered in this analysis.

The analysis is based on Statoil DBR data and Statoil internal information in the period 2007 to 2014 [49, 50]. The fields that in the past have used AST most frequently were preselected to establish a foundation for comparison. Runs performed by all three directional suppliers are included in the analysis. The ROP for runs with AST are compared to the ROP for runs without AST. The runs compared are drilled in the same fields and in close offset wells. Most runs evaluated are using the same bit type (mostly PDC), and similar downhole conditions can be assumed due to proximity. To make the analysis as accurate as possible, runs that had drilled less than 30m were excluded, in addition to runs with abnormally large variance.

The findings are displayed by graphs and are separated by fields to illustrate how the ROP is affected in close offset wells. The data is separated into bins where each bin represents a given number of runs, performed at close locations. The blue bins display the average ROP for the runs with AST, while the green bins display the average ROP for runs without AST. More detailed description on the analysed wells is given in Appendix B.

7.2 Results

8 ½" section

The findings in the 8 ½" section are based on 94 runs, 46 runs with AST and 48 runs without AST. The results are displayed in figure 47.

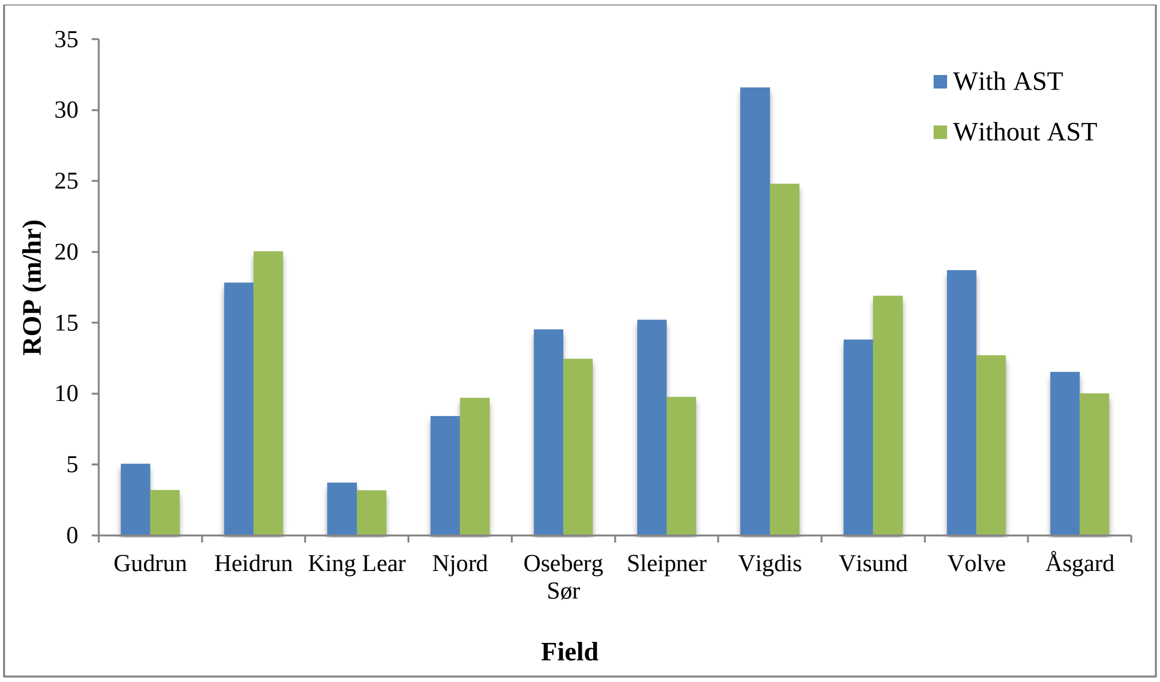

Figure 47: Comparison of ROP values with and without AST in the 8 1/2" section by field

Findings:

Table 11: ROP improvements (%) with AST for each field in the 8 1/2" section

Field	ROP with AST (m/hr)	ROP without AST (m/hr)	Reduction or improvement in ROP for runs with AST (%)
Gudrun	5,06	3,2	58% improvement
Heidrun	17,84	20,05	11% reduction
King Lear	3,72	3,19	17% improvement
Njord	8,41	9,7	13% reduction
Oseberg Sør	14,53	12,46	17% improvement
Sleipner	15,21	9,78	55% improvement
Vigdis	31,6	24,8	27% improvement
Visund	13,8	16,9	19% reduction
Volve	18,7	12,7	48% improvement
Åsgard	11,54	10,02	15% improvement

Summary:

For most fields in the 8 ½" section the AST tool seems to have a distinct ability to increase the ROP (table 11). For 7 out of 10 fields the ROP is higher when AST is run in the assembly. The average ROP for all runs with AST is 14,04m/hr (46.1ft/hr), while the average ROP for all runs without AST is 12,28m/hr (40.3ft/hr), meaning that the overall ROP is increased by 14% when using AST. For some specific fields, such as Gudrun and Sleipner, the ROP is significantly increased for the AST runs. The ROP improvements on Sleipner compare well with Statoil experiences. Prior to implementing the tool stick-slip problems were frequently encountered on this field. The tool has most likely served to reduce the stick-slip severity and thereby increased the ROP.

12 1/4" section

The findings in the 12 ¼" section are based on 29 runs, 11 runs with AST and 18 runs without AST (figure 48).

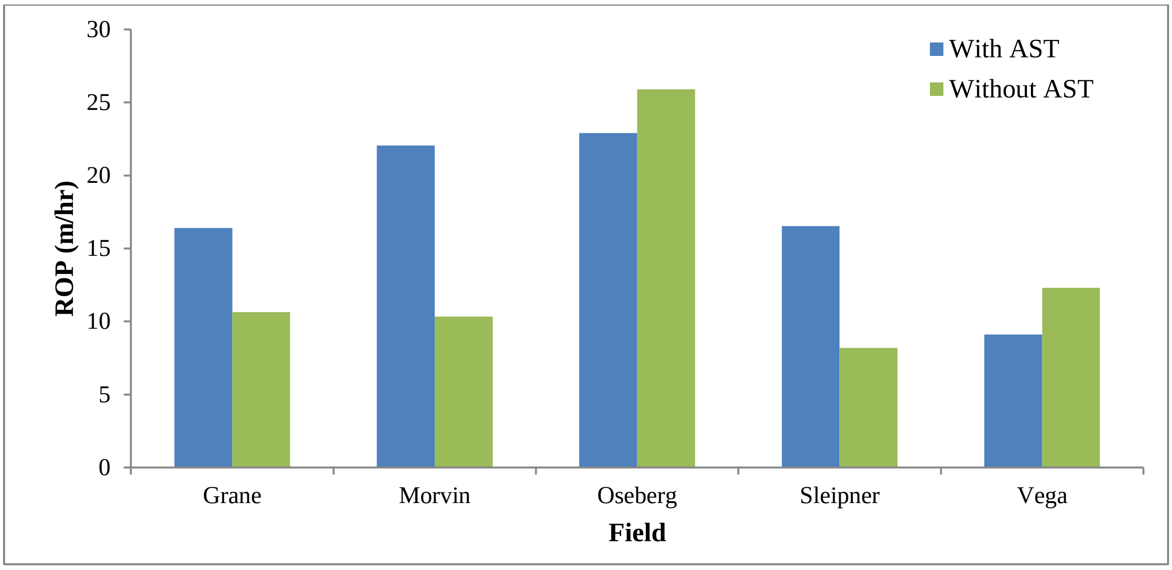

Figure 48: Comparison of ROP values with and without AST in the 12 1/4" section by field

Findings:

Table 12: ROP improvement (%) with AST for each field in the 12 1/4" section

Field	ROP with AST (m/hr)	ROP without AST (m/hr)	Reduction or improvement in ROP for runs with AST (%)
Grane	16,4	10,64	54% improved
Morvin	22,05	10,34	113% improved
Oseberg	22,9	25,9	12% reduction
Sleipner	16,53	8,19	102% improved
Vega	9,1	12,3	26% reduction

Summary:

In the 12 ¼" section the ROP is significantly increased for 3 fields when AST is incorporated in the assembly (table 12). For the remaining two fields, a small decrease in ROP is seen when AST is incorporated. The average ROP for all runs with AST is 17,9m/hr (58,72ft/hr), while the average ROP for all runs without AST is 10,74m/hr (35,23ft/hr), meaning that the ROP is increased by 66% when incorporating AST in the assembly.

17 ½" section

For the 17 ½" section 11 runs are evaluated, 7 runs with AST and 4 runs without AST. All runs are performed on Gudrun (figure 49).

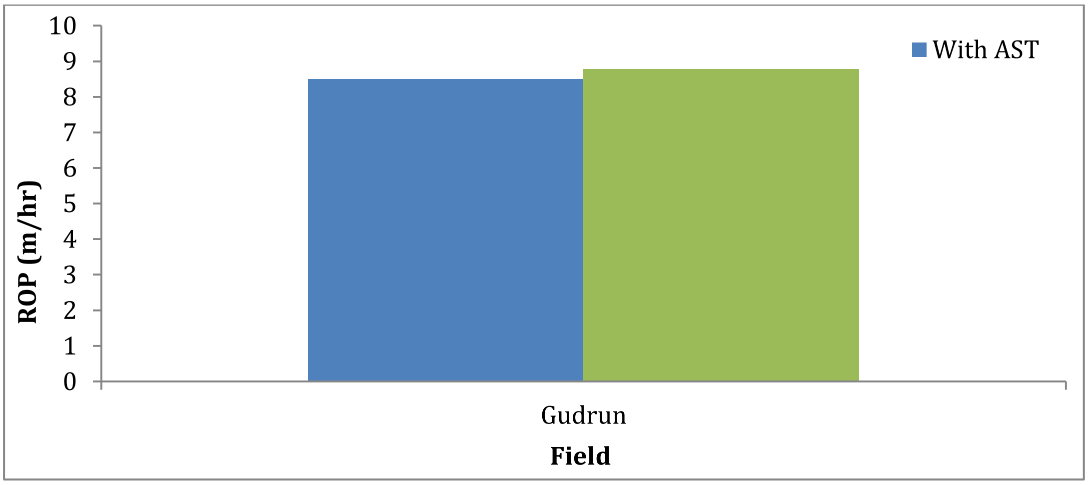

Figure 49: Comparison of ROP values with and without AST in the 17 ½" section on Gudrun

Summary:
The findings for this section are based on a limited amount of runs, which makes the results more questionable. As seen from the graph the AST shows no effect on the ROP level. The ROP with AST is 8,5m/hr (27,9ft/hr), while the ROP without AST is 8,77m/hr (28,8ft/hr), meaning that the ROP is decreased by 3% for the AST runs. The low ROP is most likely caused by other factors than detrimental stick-slip and the tool might not have an effect on these problems. As mentioned in section 6.7, unconsolidated sands are often the main source of problems in this section. Under such conditions the AST tool might not be able to improve the ROP.

All sections:

In total 134 runs were analysed with regards to the ROP, 64 runs with AST and 70 runs without AST. The ROP improvement for each section with and without AST is shown in the table 50.

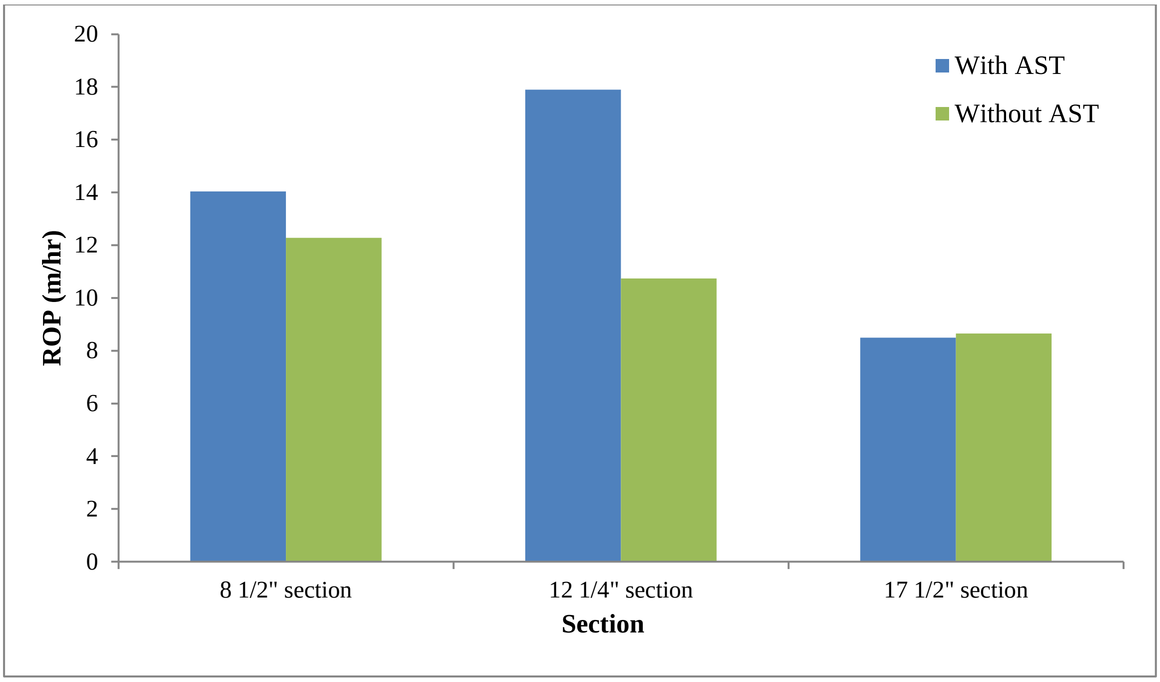

Figure 50: Comparison of ROP values with and without AST by section

For all the runs with AST the average ROP is 13,98m/hr (45,73ft/hr), compared to 11,57m/hr (37,95ft/hr) for the runs without AST. In total the ROP is improved by 21% for all sections when AST is utilized.

7.3 Conclusion:

For the 8 ½" and 12 ¼" sections the ROP values are overall improved for the AST runs. The results in these sections are more viable as more runs are analysed. However, it is clear that the performance varies from field to field. This implies that the AST performance depends on several factors, such as well conditions, placement and problems met downhole. The AST tool has an effect in some formations and on some problems, but not all.

The results of this analysis compare well with previous reports and experiences, described in section 4.5.1, which also indicates increased ROP when utilizing AST. Compared to the Schlumberger report these values show a similar improvement in the ROP. For the Schlumberger analysis without filtering it was concluded that AST led to 32% increase in ROP. This can be compared to the performance analysis made in this thesis. In this analysis the ROP is increased with 21% for all AST runs, indicating some disparities from the Schlumberger report. The data material evaluated can explain the disparities. For this analysis runs in the period 2007 to 2014 for all three directional suppliers are reviewed, in contrast to the Schlumberger report, which evaluated runs performed in the period 2010 to 2012 with Schlumberger as the supplier. Nevertheless, the conclusion is the same. **The AST tool shows an ability to improve the drilling progress.**

8. Discussion

Complete avoidance of vibrations is currently unattainable as there is continuous contact between the bit/BHA with the formation during drilling. However, by introducing proper counteractive measures, a large portion of the damages and additional expenditures caused by drillstring vibrations are preventable. As seen in previous sections, the severity of drillstring vibrations is not only controlled by drilling parameters and downhole conditions, but also by the BHA design and by tools implemented in the assembly.

The most important factors to prohibit severe drillstring vibrations are comprehensive knowledge and understanding of downhole vibrations and the generating sources. To be able to establish correct counteractive measures, key personnel must be able to identify were the vibrations are coming from or were they are expected to occur. Uncomplicated adjustments, such as defining the perfect range of drilling parameters and selecting the correct bit, should be performed early on, in the pre-drilling phase. After these actions have been performed, alternative techniques and tools should be considered. The best approach to minimize shock and vibration is to design a BHA that will render lowest chance of vibration and then monitor the response in real-time. Real-time drilling optimization services help drillers to detect shock and vibrations, determine the source and allow for counteractive measures to be initiated. The drilling performance is optimized in real-time. In addition it gives an indication on how the predetermined BHA design responded to downhole vibrations and hence the outcomes from the BHA design optimization software can be evaluated.

When analysing the effect of various mitigation tools and techniques it is challenging to come up with conclusive answers, as several factors will influence the level of vibration and must be taken into consideration. In order to make a conclusive judgement on whether or not the tools and actions reduces the severity of the vibrations one must drill under identical conditions and compare one procedure with the other. As this is challenging to carry out, the conclusions are based on conversations, comparative case studies, literature and experiences made by Statoil and the directional suppliers. In addition to a performance analysis for the AST tool.

A summary of the tools and techniques discussed in this thesis are given in Appendix B.

8.1 Optimal BHA configuration with BHA design software

A standard, optimal BHA design does not exist, however, several adjustments can be made to the BHA configuration pre-drilling to make it more vibration resistant. As vibration mitigation has gotten increased focus throughout the years, the suppliers have developed BHA design optimization software, to analyse the stress distribution in the BHA (section 6.1). It is practical to conduct such analysis to compare various changes in placement and design of BHA components, particularly stabilizer placement, which tend to dominate the dynamic response of the system. As the optimum BHA design will vary according to operation, this software is one of the most important tools the service companies possesses to develop a vibration resistant BHA. The software has also proven valuable in validating the effect of alternative configurations, such as tapered stabilization, and can be used to develop best practices.

Some limitations exist in the BHA modelling process:

- The analytical tools have various complexities and although advanced the accuracy of their predictions can be limited. The software relies on input parameters and assumptions, and hence uncertainties are introduced. Disparities between the predicted behaviour and field observations can occur.
- The drilled trajectory is often slightly different than the planned drilling scenario and the downhole drilling environment can unexpectedly change, making it difficult to predict the actual conditions downhole
- As multiple suppliers often deliver different parts of the BHA, comprehensive pre-planning of the BHA becomes challenging or not possible. In such cases it is important that the operator and the suppliers collaborate on designing a vibration sustainable BHA. Operators may also consider "total delivery contracts" more often, giving one supplier the full responsibility. Such contracts will make it less complicated to conduct proper modelling of the BHA in the pre-drilling phase
- The engineer's choice when designing the BHA might be limited. BHAs often contain elements, such as RSS, LWD and MWD with fixed dimensions and mechanical properties, leading to constraints on the BHA configuration options. Only the basic configuration alternatives, such as placement of stabilizers, can be adjusted
- The simulations can be time consuming, limiting the applicability
- BHA design modelling is conducted too seldom. Some suppliers only conduct BHA modelling in certain operations, particularly were vibrations are expected to be a vast problem. A great potential lies here, BHA modelling should be conducted frequently
- BHA designs that have proven successful in reducing the risk of vibrations are not properly analysed. By reviewing assemblies indicating good results best practice can be established, enabling smoother drilling in future operations

Schlumberger appears to be the directional supplier possessing the most advanced and accurate software, with a particular merit being the ability to predict and simulate cutting structures. This feature makes it easier to predict the optimum cutter size, blade count, backrake angle and position. In addition it enables the supplier to understand the interaction between the underreamer and the bit. The negative feature is that the software is used to seldom. In contrast, Halliburton stated that it is an internal requirement within Halliburton that all BHAs are monitored in MaxBHA. This is a great encouragement that the other suppliers should consider to enforce.

It is highly important to have a modelling program were predicted behaviour and field observations compare well. The software should also enable quick and easy comparison of potential BHA design candidates. Due to the limitations described above the software should be used as a guideline, and calibrated with offset well information for higher accuracy. Even though the software used have some limitations it is worthwhile and have proven highly valuable to minimize shock and vibration. A performance assessment based on BHA design optimization software is a good predictor for field results. By predicting the vibration tendencies in the BHA and drillstring the drilling performance can be improved. BHA design optimization programs should be used prudently to customize the BHA for the specific operation in store, taking generating sources into account. Uncomplicated and inexpensive changes can thereby be made in the pre-drilling phase, reducing the risk of tripping and NPT at a later stage. Advanced and exact BHA modelling software can lead to several benefits and cost reduction. The suppliers should therefore be encouraged to further develop their BHA modelling software for more accurate results in the future.

8.2 Small changes lead to big gains

Referring to section 4.3 it is described how small inexpensive changes made to the components in the BHA could potentially lead to reduced risk of encountering detrimental vibrations. Sharp edges on bits, stabilizers and reamers should be bevelled or completely removed, to prevent cutting stresses at the borehole wall and thus provide better drilling conditions. This is particularly important in deviated boreholes were the components are subject to high contact forces over long areas. By performing a small change, significant benefits can be seen in terms of reduced vibration level. This change has little additional cost and is not particularly time consuming. However, preventing destructive vibrations will appreciably reduce the drilling expenditures.

It appears like the directional suppliers have insufficient focus on this subject and improvements can be made. The operators and the suppliers should invest more efforts in small modifications that can be made and not only focus on the tools “guaranteeing” an instant fix or the operational procedures with vaster impact. The operator should put pressure on the suppliers to monitor this closely. All changes potentially providing a more vibration resistant BHA should be considered and hence increased focus must be given to the edge geometry on downhole components in the future.

8.3 Careful use of some specific vibration inducing tools

Some tools should be used with care and only implemented if absolutely necessary. Tools such as flex stabilizers and underreamers are recognized for having derogatory effects on the vibration level. These tools have specific usage areas and thus the implementation might be inevitable in some operations.

Although it is known that flex stabilizers might be unfavourable in regards to drillstring vibrations, suppliers frequently use the tool to create dogleg. Referring to section 4.2.1, in some operations flex stabilizers might be used without actually needing them for directional purposes. Under such circumstances, a modular stabilizer should replace the flex stabilizer, making the drillstring stiffer and hence more resistant against vibrations. If circumstances permit it, flex stabilizers should be avoided and other options considered, particularly in vertical wells, where flex stabilizers are less expedient. If the BHA is pulled during the operation and it is decided that the directional work is only small corrections with low dogleg, a non-flex stabilizer should be easily obtainable to make a quick change. The directional suppliers should keep this finding in mind, particularly Baker Hughes, who uses flex stabilizers in most directional drilling operations.

It would absolutely be preferable to avoid using underreamers in drilling operations, to prevent detrimental vibrations, as they lead to complex and challenging operations. Drilling and reaming could be performed in two separate runs. However, the costs of performing two runs must be compared to the costs induced by the challenges when doing it in one run. Usually, the latter is believed to generate less vibration and to be more cost effective, avoiding an additional run. When using underreamers one should be particularly attentive and carefully consider how the BHA can be optimized. If alternative methods exist or the underreamer could be avoided, this is favourable.

8.4 Roller reamers

Referring to section 4.4, roller reamers can prove beneficial in difficult and hard rock formations by reducing the friction against the wellbore. One should consider replacing stabilizers exposed to high lateral forces at the contact points with roller reamers. When the stabilizers are subjected to high side forces they might start digging into the formation, generating stick-slip. By incorporating roller reamers the risk of generating torque at the stabilizer is reduced and hence coupled vibrations and stick-slip can be avoided. Decoupling of whirl and stick-slip should be a motivator for running roller reamers. If roller reamers are unattainable for some reason, one could potentially decouple whirl and stick-slip by increasing the lubricity of the mud (section 2.2.3). By doing this the stick-slip level might be reduced and hence the WOB can be increased, to minimize whirl.

The suppliers use roller reamers to various degrees, and could benefit from utilizing the tool more often, particularly in long laterals and high friction formations, such as carbonates. In these formations stick-slip can by generated by the string interaction with the borehole wall and hence roller reamers are recommended over AST, as AST has largest effect when stick-slip is generated by the bit cutter action. The directional suppliers confirmed that good results have been recorded when utilizing roller reamers in various operations. Schlumberger used the tool in challenging formations on Brent successfully, as the tool inherently controlled the torque response and prevented the system from going into backwards whirl.

The decision to include roller reamers in the BHA configuration depends on their operational impact. Roller reamers should only be used when needed, if high side loads and torque exists. Also, if the stabilizer-wellbore gearing induces whirl, roller reamers can also prove beneficial. In over gauge hole sections the tool might impose negative consequences to the drilling system. The roller reamer has three contact points and may therefore actually induce vibrations in overgauge holes. Roller reamers, like every other tool added to the assembly for vibration mitigation, should only be implemented if required, provided that the system is not subjected to additional risk. In recent days the roller reamer has become more reliable and the risk of failure is low compared to earlier.

8.5 Anti-vibration tools

Making a conclusion on whether or not anti-vibrations tools are beneficial is challenging, as several aspects of drilling have to be taken into consideration. The industry has performed several tests to determine the effect of these tools, with various outcomes.

Both directional suppliers and operators are sceptical to adding additional tools to the drillstring, particularly if the tool is relatively new in the marked and the effectiveness has not been adequately proven. AST and Frank´s HI tool are no exceptions. Even though Tomax and Frank´s International claim that no risk is imposed to the drilling system by implementing the tools, this can be questioned. An additional connection will complicate the BHA, possibly increasing the risk of experiencing problems, such as lost in hole situations. Consequently, the suppliers prefer running the BHA as simple as possible, not complicating it more than necessary.

Anti-vibration tools should only be implemented in the BHA if the circumstances call for it. Each BHA must be adapted to the wellbore conditions and the specific operation at hand. If offset wells, formation hardness or other conditions indicates that the well will be troubled with detrimental vibrations, anti-vibration tools should be considered. In other operations the tools might be unprofitable.

8.5.1 AST

The main purpose of the AST tool is to stabilize the downhole forces and thereby reduce the risk of severe stick-slip and downhole failures. By supressing stick-slip the ROP is improved. After conversations with Tomax, it became evident that several well-executed operations and case studies exist. As seen in this work, comparative examples, performed under identical conditions were made available, clearly illustrating the benefits. Tomax could report that during field testing the speed has been doubled when implementing the tool, with largest improvements where the vibration levels are highest.

In chapter 7, a performance analysis on the AST tool was made. The analysis was based on 143 runs and the goal was to determine whether or not AST serves to increase the ROP. The findings were overall satisfactory. For most comparable runs the tool showed a distinct ability to improve the ROP. For all runs combined the ROP was increased with 21%. These findings are substantiated by the analysis made by Schlumberger (section 4.5.1). In this analysis the claimed effects of the tool were also verified. For the analysis with filtering it was concluded that the average stick-slip was reduced with 45% and that the ROP was increased with 17,3%. As Schlumberger is a third party with no self-interest in the tool, they have no economic benefits from promoting the tool. Based on these findings the use of the AST tool appears to be beneficial.

Through conversations with Statoil and the directional suppliers it was made clear that no negative operational impacts have been experienced when running the tool in recent years. Although it is not always possible to quantify the effects, little additional risk is imposed on the drilling system by adding AST to the assembly. This is an important factor that might encourage future use. As presented in section 4.5.1, indications suggest that the tool in several applications have served to its purpose by reducing stick-slip. Employing AST can therefore prove valuable, particularly when drilling in challenging formation with interbedded layers and during operations with PDC bit. When high stick-slip levels have been experienced in offset wells or when bit induced stick-slip is expected, e.g. in hard formations, the tool can also be beneficial. However, the clients should not be undiscerning in the use of the tool. In situations where it is not needed or if the costs exceed the economic win one should of course drill without AST.

There are some uncertainties on the tools impact and benefits. It is not always possible to quantify the effect of the tool. The industry opinion seems dual, with mixed experiences, as it is difficult to delineate what is causing or alleviating the problems downhole. The results are difficult to compare as operators and suppliers use different applications in the attempt to quantify the effect of the tool.

“Apple to apple comparison” is needed to obtain sustainable results on the tool performance in the future.

As seen from the analysis in chapter 7, the effect varies according to field. Some specific factors will affect the performance and profitability of the tool. Table 13 illustrates that the tool is only needed in specific formations, depending on the hardness and likelihood of stick-slip vibrations. A highly important finding that should be emphasized is the effect of AST in long, vertical chalk sections (described in section 4.5.1). In this section the drillstring friction will increase, AST tool performance is still intact, but the tool has little effect on this problem. The utility of the tool is supressed in such formations, as the tool serves to reduce bit-induced stick-slip and has less effect on stick-slip generated by the friction between the drillstring and the wellbore. Through conversations with Statoil engineers and by reviewing various field experiences this finding was reinforced. Statoil have used AST in thick limestone intervals without recording lower stick-slip tendencies. It should also be mentioned that in vertical wells the need for AST might be lower, as severe stick-slip is less likely to occur. In vertical wells it is easier to control the WOB and thereby control the stick-slip level, without using AST. However, bit-induced stick-slip and string-induced stick-slip often occur simultaneously, if the tool can reduce one of the two (bit-induced stick-slip), the drilling performance will improve.

Table 13: AST usage areas

Conditions	Hard formation	High stick-slip levels expected	Normal (soft) formation	Long chalk sections (near vertical)
AST usage area	Highly recommended	Highly recommended	Not required	Little effect, not recommended

The most significant factor limiting the use of the AST tool, besides difficulties in quantifying the effect, seems to be related to cost. AST is quite expensive compared to other tools and data does not always support the cost differential. Tomax needs to be more technical in their presentations and dialogue in the future to provide deeper substance, validating the cost effectiveness. Nevertheless, if the tool enables reduced vibration level and a small increase in ROP, the costs of the tool will be less significant than the expenditure incurred by trips and NPT.

8.5.2 Frank`s HI tool

The purpose of Frank´s HI tool is to minimize axial and lateral vibrations. The tool was developed in 1996, but has only been used in the North Sea for the last 3 years and thus the effect of the tool is not completely verified. Statoil has only implemented the tool in a few selected wells and the results are not conclusive. However, it is seen from the run list that other large operators such as ConocoPhillips and BP have implemented the tool more frequently in the North Sea, indicating benefits in reducing the vibration level.

Frank´s International has in several operations implemented Black Box recorders to validate the effect of the tool. The use of Black Boxes has made it easier to convince the industry on the advantages of this tool. As seen in section 4.6.1, several case studies and reports have been presented indicating that the tool decouples vibrations generated at underreamer/bit from the rest of the system and reduces the vibration level. By reviewing the Black Box data from various fields, indications on the positive effects of the tool were substantiated. Experience has to this date not implied that the system is subjected to additional risk when incorporating the tool in the assembly. In hard formations or in operations were severe axial and lateral vibrations are expected or previously experienced, the tool might be beneficial.

Schlumberger has in the past been willing to go on record and provide evidence that specific independent down-hole tools are beneficial when run in their BHAs. As mentioned, when running the tool on Johan Sverdrup, Schlumberger stated; "having the tool made it easier for us to mitigate the vibration than on other wells that have not had the tool in the BHA". This comment came from an independent source and should therefore be emphasized. Although Frank´s HI tool and AST cannot be directly compared, as they have different functionality and usage areas, it was also added in the report that the HI tool is a cost-effective alternative, being less expensive than AST. Even with Black Boxes utilized the overall cost was significantly lower [32].

Even though the HI tool has indicated some good results, there are some limitations. Both Statoil and the suppliers have confined experiences with it in the North Sea, compared to AST. This makes it more challenging to establish the risk and benefit trade-offs. The effects confirmed by the Black Box recorders are good validation, but not scientific proof. Not all engineers run Black Boxes in their wells, due to additional costs, and thus the ability to compare the results are limited. As the effects of the tool have not yet been properly quantified it is highly important that the operator and suppliers are systematic in the use of this tool in the future, in order to obtain more conclusive data on the performance.

The placement of the tool seems to be the most significant factor limiting the use. The optimal placement of Frank´s HI tool is near the bit, making the directional suppliers hesitant to implement the tool, as it can have a derogatory effect on the directional objectives. Although Frank´s International claims that the trajectory will not be affected by the placement, it is highly important that this is adequately proven before using it in this position. In addition, Frank´s International states that it is critical that the tool is placed close to the point where the vibrations are generated. This imposes some difficulties, as it can be challenging to foresee the generating source prior to drilling, and by placing it elsewhere the functionality might be compromised. A future goal for Statoil should be to perform systematic testing of the HI tool. If this implies that the tool serves to its purpose, it might contribute to minimize shock and vibration for Statoil in the future.

The most positive finding on AST and Frank´s HI tool is that the directional drilling suppliers most often seem satisfied after running the tools in their BHAs. This may be natural and self-serving, as less vibration will lead to less damage and thus lower maintenance, repair costs and NPT will result, providing better asset management for the companies. Nevertheless, this is a good indicator that the tools can be beneficial in minimizing shock and vibration, and improve the drilling efficiency.

8.6 Underreamer attention

It has become evident through conversations with experienced engineers and by reviewing field experiences that underreamers increase the occurrence of shock and vibration. As this technology is frequently used in the North Sea the industry should increase the attention on vibration prevention in underreaming operations. Extensive work should be done in the pre-drilling phase to predict tool behaviour and possible damaging scenarios. The BHA design optimization software should be used to predict effective stabilization placement and the spacing between the underreamer and the main body of the BHA. By doing this the vibration level can be reduced and one can ensure that the vibrations generated by the reamer do not affect other components in the BHA. During the operation real-time data must be monitored closely and mitigation actions developed.

It is imperative to understand the interaction between the underreamer and the bit. Bit type and aggressiveness will have a tremendous effect on the vibration level in underreaming applications. The interaction should therefore be evaluated closely pre-drilling. Measures to reduce the aggressiveness of the bit, preventing the bit from out-drilling the reamer are implemented by all suppliers in various degrees. By implementing DOCC one can provide a bit that is less aggressive than the reamer and hence avoid weight transfer and vibrations. All of the directional suppliers should develop BHA modelling software with the ability to predict cutting structures. With this present the cutting structure of both bit and underreamer can be evaluated, making it possible to adjust the interaction, prior to drilling through interbedded formations.

The principle of an expandable stabilizer placed above the reamer, introduced by Baker Hughes, is an effective measure indicating good results. By stabilizing the components in the enlarged hole one can potentially push the drilling parameters to increase the progression, without additional vibrations. This vibration mitigation technique is particularly valuable in vertical and near vertical wells. In deviated wells, undergauge stabilizers have an ability to lean against the wellbore wall and thereby stabilize themselves without the need of an expandable stabilizer. Halliburton and Schlumberger should consider implementing this technique. By combining DOCC, bevelled edges on the reamer and proper stabilization, shock and vibration can be minimized.

Implementing AST in underreamer operations has become more common in recent years. The following recommendation was made by [51]: “Where there is torque limitation on rig, consideration should be given to running anti-stall tools above the reamers in the BHA” and this was defined as best practice. By placing the AST tool above the underreamer the weight-sensitivity of the reamer can be reduced, as the tool serves to regulate the DOC of the bit. This can potentially allow for higher WOB and RPM, and thus increased ROP. It can also contribute to the underreamer working more evenly, resulting in less stick-slip and less erratic surface torque. The benefits of including AST in the assembly in underreamer operations are substantiated by the findings made in section 4.5.1. Statoil have performed several runs with AST in underreamer applications with great success. When using AST in underreamer applications it is highly important that the tool is placed above the underreamer.

The HI tool can also be an alternative to increase the drilling performance in underreamer operations. Frank`s International have used the tool for this purpose multiple times indicating good results. The underreamer has a tendency of generating vibrations travelling downwards in the string. The MWD package placed below the underreamer contains sensitive components that are particularly prone to vibration damage. As the HI tool serves to decouple vibrations generated at the underreamer from the bit, this could be an effective measure. The HI tool can potentially prevent detrimental failures and allow the pilot run to run smoothly. A future consideration could be to integrate two HI tools in the assembly, above and below the MWD tools, completely isolating the MWD package from vibrations generated at the bit and underreamer.

8.7 Tapered stabilization

Tapered stabilization in large hole sections should be made a priority, as it can reduce the risk of experiencing twist-offs, lost in hole situations and NPT. A downscaling of the stabilizer size upward in the assembly will lead to better distribution of side forces and thereby reduce the bending moment in the area above the top stabilizer. This technique will enable the drillstring to lean against the borehole wall, making the transition smoother.

Assemblies drilling smaller hole sections are normally exposed to lower vibration levels and have lower risk of vibration related failures. Assemblies drilling 17 1/2” holes and similar sizes on the other hand are often exposed to more severe drilling conditions and tapered stabilization should therefore be confined to these sections. The technique is particularly beneficial in deviated wells, as the area discussed will experience significant stress. In vertical wells tapered stabilization will be of less importance, as the bending moment above the stabilizers often is less significant.

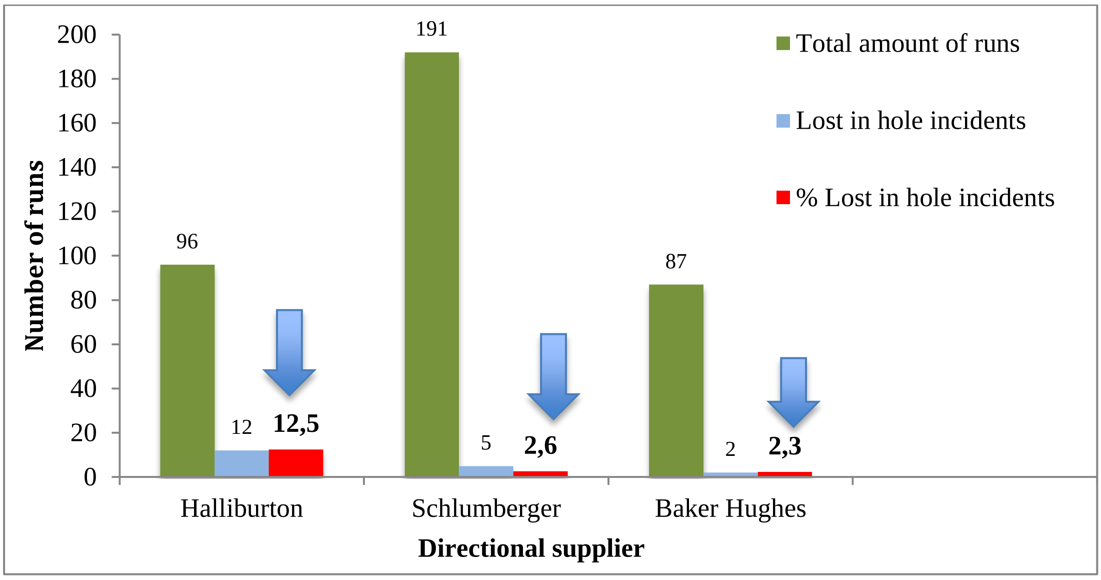

Figure 51: Lost in hole incidents in the 17 1/2" section by directional suppliers [52]

Figure 51 shows the percentage of lost in hole incidents in the 17 ½" section for Halliburton, Schlumberger and Baker Hughes in the period 2010-2012 (red columns), on Statoil operated fields. Lost in hole includes all incidents were the BHA, or parts of it, have been left in hole, and BHAs that have been fished out later on. In addition, the total amount of runs for the three companies are displayed in green and total amount of lost in hole incidents are presented in blue. The results summarized confirm that less broken string incidences are experienced by Baker Hughes compared to Halliburton in this section. This may be directly correlated to the use of tapered stabilization. Neither Halliburton nor Schlumberger implement the tapered stabilization technique. Prudent use of this technique can potentially result in reduced damage caused by drillstring vibrations in the future. As seen from the figure, Schlumberger and Baker Hughes have relatively similar trends. A possible explanation to why Schlumberger experience less lost in hole incidents than Halliburton might be that their BHA design optimization software is more advanced, allowing them to optimize the BHA more effectively. However, Schlumberger might achieve even better results by implementing tapered stabilization.

8.8 Future technology

8.8.1 Active Vibration Damper (AVD)

In recent time new technology has emerged that serves to minimize shock and vibration. APS has developed the industry's first "intelligent" shock sub, which potentially can reduce the axial, torsional and lateral vibration levels. The tool is 9.8m (32ft) long and is normally placed near bit in vertical drilling and above the MWD tools in directional drilling applications. The downhole tool autonomously adapts to changing downhole BHA motion in real-time and thereby reduces the axial and torsional vibration level. Structurally, the tool resembles a shock-sub, with an additional damper section with programmed stiffness. An interesting feature is that an integrated motion sensor measures displacement and changes the dampening factor range based on drilling conditions, and thereby self-adapts to the continuously changing environment. As the tool string dampening is kept in the right range the AVD could potentially serve to minimize vibration, maintain the bit in contact with the formation and thereby increase the ROP. The AVD can also be used to record vibrations for later download, as it can be run as a self-contained drilling tool with no calibration or rig maintenance required [53].

Claimed benefits:

- Less severe bit/BHA vibrations
- Longer bit life and fewer trips
- Improved drilling efficiency
- Faster penetration rates
- Significant cost/foot savings

AVD has to this date not been implemented in the North Sea and the lack of proof on its functionality leads to reluctance to use it. Statoil or the directional drilling suppliers should perform systematic testing of the tool to confirm or deny that the tool reduces the vibration level as claimed. APS can refer to good results in the field as it has been implemented in commercial jobs in Oman, Canada and Texas, leading to improvements in ROP and footage per bit. In Canada, 44% improvement is claimed in bit footage and Baker Hughes logs indicated that the vibration level was low and significantly improved compared to offset wells [54]. AVD might contribute to reduce the occurrence of vibrations in the future.

8.8.2 Wired Drill Pipe (WDP):

Real-time downhole data monitoring is extremely important for early identification and prevention of drillstring vibrations. Sensors are placed in the BHA/drillstring to record downhole data and can be read at surface to adjust the drilling parameters and thereby minimize vibration and optimize the performance. Currently, a limited number of sensors are placed within the BHA, making it challenging to monitor the vibration level along the entire drillstring, and to establish the generating sources.

To get a better insight into the vibrational picture, a relatively new technology called wired drill pipe can be implemented. WDP makes it possible to place several sensors in the BHA, providing high-resolution vibration measurements. Multiple sensors will enable along-string measurements and thereby improve the vibration control and enhance the understanding of the downhole environment. Large operators such as Eni and ConocoPhillips have in recent years implemented this technology. However, Statoil is for the time being not employing WDP.

Multiple sensors distributed in the assembly will improve the data feedback and makes it easier to predict whether the vibrations are confined to a specific area or distributed along the entire string. The real-time decision-making will be improved, as it is possible to monitor the vibration level higher up in the system. The technology could prove particularly valuable to solve the problems met in large hole sections. As mentioned in section 6.3 the reason for twist-offs in these sections are often difficult to identify due to lack of sensors higher up in the assembly. With WDP the source of vibration can be identified and thus the technology makes it easier to perform correct mitigation action. WDP will make it possible to distinguish where the vibrations are generated, how they travel within the string and where they are most severe. More detailed information, captured during drilling, will lead to higher level of automated control and thereby improve the reliability of each downhole component. The current hindrance is that the technique is expensive, but as this technology can serve to minimize shock and vibration it should be used in the future.

9. Conclusions

Drillstring vibrations are separated into three primary vibration modes. These vibration modes can be coupled to each other and thus makes it more challenging and complex to abate shock and vibrations. Lateral vibrations appear to be the most feared and destructive vibration motion, and this mode is strongly coupled to axial vibrations.

There are several tools and techniques that can be used to minimize shock and vibration to the BHA and thereby improve the overall drilling performance. The following mitigation actions are recommended:

- The assembly must be sufficiently stabilized. The span length, effective placement, edge geometry, number and size of stabilizers should be analysed in the BHA design optimization software. Both operators and the directional suppliers will benefit from frequently using this software to enable proactive, rather than reactive BHA designs. A future goal should be to further develop this software for closer alignment with field observations
- Roller reamers should be used more frequently to decouple whirl and stick-slip in selected holes
- If bit-induced stick-slip is expected, e.g. in hard formations, AST can prove beneficial. The AST tool shows an ability to reduce the vibration level and at the same time improve the ROP. The technology requires critical evaluation and the associated risks and costs of the technology must be compared with the gain in overall performance
- Frank`s HI tool can be used to mitigate axial and torsional vibrations. However, the effect of the tool has not been properly documented. Systematic testing should be performed to ensure that the tool is a worthwhile application for future use
- In underreamer operations one should highly consider placing an expandable stabilizer above the reamer to stabilize the enlarged hole section. In addition, the underreamer should be more aggressive than the bit. DOCC can be implemented to obtain optimal weight distribution.
- Tapered stabilization should be considered in large hole sections (17 ½" and larger), as this technique can result in less lost in hole incidents. The drillstring can lean against the wellbore wall, making the area above the top stabilizer less vulnerable to drillstring vibrations
- The shock and vibration level must be monitored closely in real-time, to determine the optimum drilling parameters (WOB, RPM, flow rate and mud lubricity) and thereby minimize shock and vibration

Contract incentives rewarding failure free runs and high drilling efficiency, together with new technology, such as WDP, will contribute to increase the focus on vibrations and thereby lead to increased drilling efficiency and reduced NPT in the future.

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Appendix A

The data in Appendix A are gathered from Statoil internal databases [49, 50]

Table 14: Runs with and without AST performed in the 8 1/2" section

Field	Rig	DD Supplier	Well	Date in	ROP	AST
Gudrun	West Epsilon	HLB	15/3-A-5	08.02.2012	3,1	YES
			15/3-A-5	18.02.2012	4,2	YES
			15/3-A-5	03.03.2012	4,6	YES
			15/3-A-5	07.03.2012	6,4	YES
			15/3-A-5	24.03.2012	7	YES
			15/3-A-5 T2	27.04.2012	3,2	NO
Heidrun	Stena Don	SLB	6507/8-D-2 AH	03.02.2009	20,54	YES
			6507/8-D-2 BH	11.02.2009	10,46	YES
			6507/8-D-2 CH	25.02.2009	22,52	YES
	Deepsea Bergen		6507/8-D-1 AH	07.01.2011	15,8	NO
			6507/8-D-3 CH	13.05.2011	24,3	NO
King Lear	Mærsk Giant	HLB	2/4-21	19.04.2012	3,6	YES
			2/4-21	30.04.2012	4,5	YES
			2/4-21A	30.05.2012	2,2	YES
			2/4-21A	02.06.2012	2	YES
			2/4-21A	19.06.2012	6,3	YES
			2/4-21	23.03.2012	6,4	NO
			2/4-21	07.04.2012	6,2	NO
			2/4-21	14.04.2012	3,5	NO
			2/4-21T2	08.05.2012	3,4	NO
			2/4-21T2	13.05.2012	2,6	NO
			2/4-21T2	18.05.2012	3,5	NO
			2/4-21A	11.04.2012	1,8	NO
			2/4-21A	22.05.2012	1.8	NO
			2/4-21A	26.05.2012	0,8	NO
			2/4-21A	11.06.2012	1,9	NO
Njord	TOW	HLB	6407/7 B1 Y1H T2	17.11.2007	12,24	YES
			6407/7 B1 Y1H T2	23.11.2007	3,15	YES
			6407/7 B1 Y1H T2	28.11.2007	12,83	YES

			6407/7 B1 Y1H T2	30.11.2007	5,4	YES
			6407/7 B1 Y1H T2	10.11.2007	2,2	NO
			6407/7 B1 Y1H	15.10.2007	11,16	NO
			6407/7 B1 Y1H	17.10.2007	15,73	NO
Oseberg	Oseberg Sør	HLB	30/9-F-13 A T2	10.11.2007	15,5	YES
			30/9-F-13 A T2	22.11.2007	14,6	YES
			30/9-F-13AT2	27.11.2007	13,5	YES
			30/9-F 14B	24.04.2008	13,8	NO
			30/9-F 14B	02.05.2008	10,4	NO
			30/9-F 14B	17.05.2008	13,2	NO
Sleipner	West Epsilon	SLB	15/9-B8	10.05.2010	16,3	YES
			15/9-B8	20.05.2010	19,5	YES
			15/9-B8	24.05.2010	16,1	YES
			15/9-B8	31.05.2010	8	YES
			15/9-B-8 A	27.10.2010	20,6	YES
			15/9-B-8 A	11.11.2010	3	YES
			15/9-B-8 A	15.11.2010	3,7	YES
			15/9-B-8 A	21.11.2010	15,6	YES
			15/9-B-8 B	07.12.2010	22,5	YES
			15/9-B-8 C	30.12.2010	10,7	YES
			15/9-B-8 C	01.01.2011	23	YES
			15/9-B-8 C	09.01.2011	16,6	YES
			15/9-B-8 D	27.01.2011	16,4	YES
			15/9-B-1 T2	03.10.2009	5,9	NO
			15/9-B-1 T2	10.10.2009	16,5	NO
			15/9-B-1 T2	17.10.2009	21,5	NO
			15/9-B-1 T2	21.10.2009	5,9	NO
			15/9-B-1 T2	23.10.2009	8	NO
			15/9-B-8	27.01.2009	0,5	NO
			15/9-B-8 A	05.05.2010	0,7	NO
			15/9-B-8 B	25.10.2010	3,8	NO
			15/9-B-8 B	06.12.2010	17,9	NO
			15/9-B-8 C	16.12.2010	1,1	NO
			15/9-B-8 D	26.12.2010	21,8	NO
			15/9B-2T2	10.02.2009	21,8	YES

			15/9B-2 T2	19.02.2010	14,3	YES
			15/9B-2 T2	27.01.2010	13,8	NO
Vigdis	Borgland Dolphin	SLB	34/7-G-4 HT2	12.04.2009	33,8	YES
			34/7-G-4 AH	15.04.2009	43,6	YES
			34/7-D-2 HT2	30.07.2008	25,3	YES
			34/7-D-2 HT2	18.08.2008	11,9	YES
			34/7-G-4 AH	15.04.2009	43,6	YES
			34/7-G-4 H	08.04.2009	51,6	NO
			34/7-G-4 CH T2	02.03.2012	24,6	NO
			34/7-F-2 H	11.07.2012	24,4	NO
			34/7-F-2 HT2	15.07.2012	19,7	NO
			34/7-H-1 H	19.03.2013	14,1	NO
			34/7-H-2 H	18.04.2013	36,9	NO
			34/7-H-2 H	28.08.2013	10,1	NO
			34/7-H-2 AH	04.05.2013	26,8	NO
			34/7-H-2 BH	18.05.2013	15	NO
Visund	COSL Pioneer	HLB	34/8-17S	25.02.2014	13,8	YES
			34/8-15S	22.01.2013	17	NO
			34/8-15S	28.01.2013	16,9	NO
Volve	Maersk Inspirer	SLB	15/9-F-10	30.05.2009	18,7	YES
			15/9-F-10	23.05.2009	4	NO
			15/9-F-10	03.06.2009	21,4	NO
Åsgard	Scarabeo 5	SLB	6506/12-Q-5 Y2H	13.11.2009	11,8	YES
			6506/12-Q-5 Y2H	17.11.2009	12,12	YES
			6506/12-Q-5 Y1H	26.09.2009	7,47	YES
			6506/12-Q-5 Y1H	21.10.2009	14,78	YES
			6506/12-Q-5 Y1H	09.10.2009	15,62	NO
			6506/12-Q-5 Y1H	14.10.2009	9,41	NO
			6506/12-Q-5 Y2H	11.11.2009	7,78	NO
			6506/12-Q-5 Y2H	02.12.2009	7,26	NO

Table 15: Runs performed with and without AST in the 12 1/4" section

Field	Rig	DD supplier	Well	Date	ROP	AST
Grane	TOW	HLB	25/11-25 A	17.02.2008	16,4	YES
			25/11-25 A	16.02.2008	2,42	NO
			25/11-25 A	21.02.2008	18,9	NO
Morvin	Transocean Leader	BH	6506/11-A-2H	18.04.2010	29,3	YES
			6506/11-A-2H	16.03.2010	27,21	NO
			6506/11-A-2H	26.04.2010	7,6	NO
			6506/11-A-4A	26.04.2010	14,8	YES
			6506/11-A-4A	03.04.2010	6,3	NO
			6506/11-A-4A	07.04.2010	5,2	NO
			6506/11-A-4A	09.04.2010	5,4	NO
Oseberg	TOW	HLB	30/9-21 S	07.04.2008	16,3	YES
			30/9-21 S	11.04.2008	27,7	YES
			30/9-21 S	14.04.2008	24,7	YES
			30/9-21 S	15.04.2008	25,9	NO
Sleipner	West Epsilon	SLB	15/9-B8	25.04.2010	21,9	YES
			15/9-B8	28.04.2010	8,8	YES
			15/9-B8	30.04.2010	18,9	YES
			15/9-B-1 T2	16.09.2009	4,6	NO
			15/9-B-1 T2	24.09.2009	3,2	NO
			15/9-B-2 T2	11.01.2010	13,2	NO
			15/9-B-2 T2	13.01.2010	17,6	NO
			15/9-B-2 T2	16.01.2010	8,7	NO
			15/9-B-2 T2	18.01.2010	5,8	NO
			15/9-B-2 T2	21.01.2010	4,2	NO
Vega	Bideford Dolphin	BH	35/8-P11H	17.04.2010	6,3	YES
			35/8-P11H	21.04.2010	11,9	YES
			35/8-P13 HT2	19.03.2010	25,7	NO
			35/8-P13 HT2	18.03.2010	8,3	NO
			35/8-P13 HT2	22.03.2010	3,1	NO

Table 16: Runs performed with and without AST in the 17 1/2" section

Field	Rig	DD supplier	Well	Date	ROP	AST
Gudrun	West Epsilon	HLB	15/3-A-5	29.12.2011	10,1	YES
			15/3-A-5	12.12.2011	9,9	YES
			15/3-A-5	20.12.2011	10,1	YES
			15/3-A-5	27.12.2011	16,2	NO
			15/3-A-5	01.01.2012	7,8	NO
			15/3-A-12	25.05.2012	4,7	NO
			15/3-A-12	26.05.2012	15,8	YES
			15/3-A-12	01.06.2012	4	YES
			15/3-A-12	05.06.2012	4,2	YES
			15/3-A-12 T2	12.06.2012	4,9	YES
			15/3-A-12 T2	16.06.2012	6,4	NO

Appendix B

Table 17: Summary of stabilizer considerations for vibration mitigation

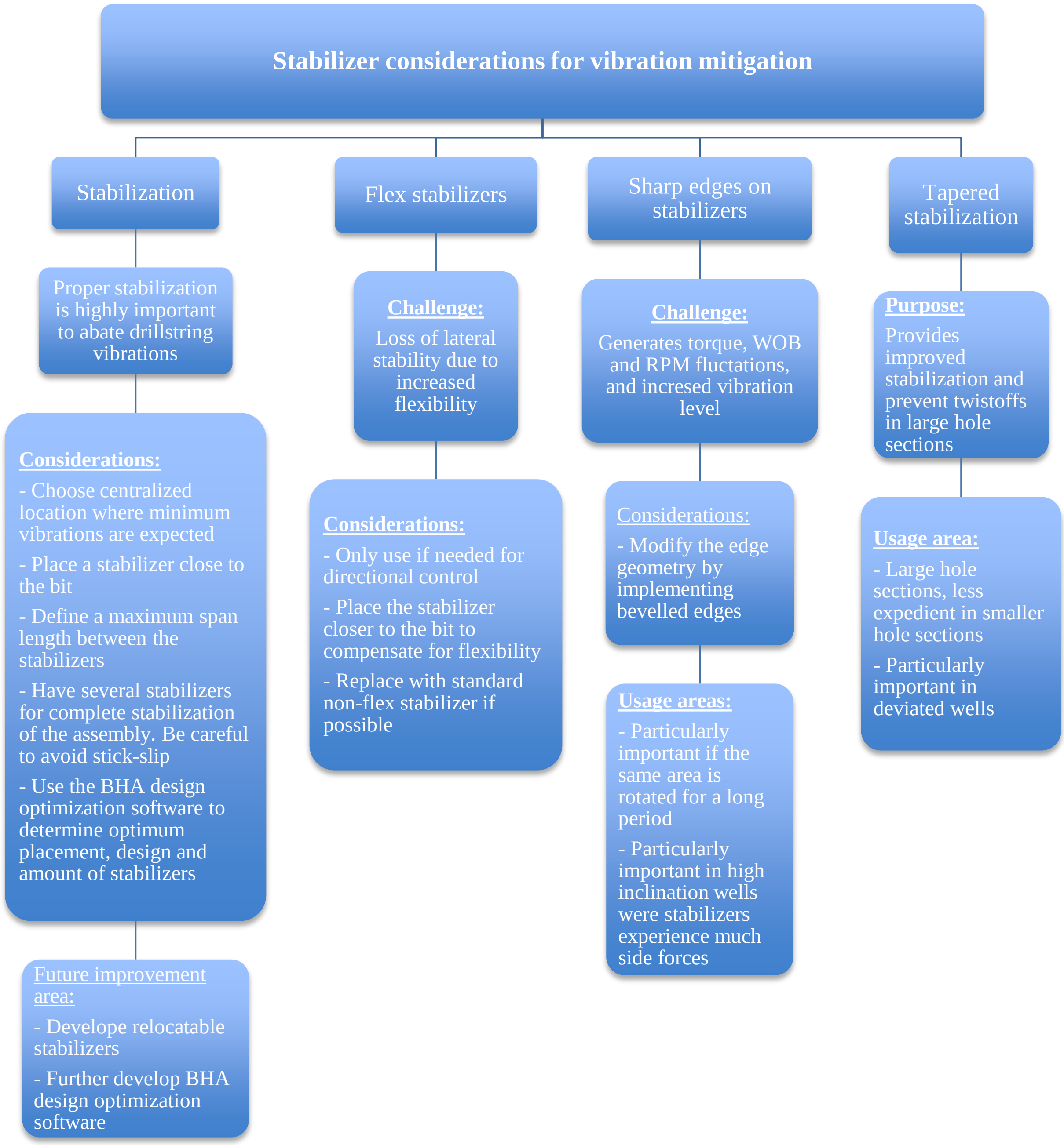

Table 18: Summary of tools for vibration mitigation

Tools for vibration mitigation

Roller reamers

Purpose:
Reduce torque generated at contact point

Benefits:
- Less vibrations (whirl)
- More torque available
- Decouples whirl and stick-slip

Usage areas:
- Tight hole
- Hard rock formation
- Stabilizers exposed to high side forces
- High friction level
- Stick slip generated by interaction between drillstring and formation

Limitations:
- Limited tool life (have improved in recent years)
- Overgauge holes

Anti stick-slip technology

Purpose:
Reduce the stick-slip level

Benefits:
- Reduces the vibration level
- Increases ROP

Usage areas:
- Interbedded formations
- High expected stick-slip levels generated by the bit
- Hard formations
- Aggressive bits
- Underreamer operations

Limitations:
- Additional component added to the assembly
- Expensive
- Diminished effect in long, vertical chalk sections
- Not needed in soft formations
- Difficult to quantify effect

Future use:
- Important to quantify the effect (apple-to-apple comparison)

Frank´s HI tool

Purpose:
Reduce axial and lateral vibration level

Benefits:
- Reduces vibration level
- Decouples vibrations
- Increased ROP

Usage areas:
- Underreamer operations
- Difficult formations
- High level of axial and/or lateral vibrations expected

Limitations:
- Additional component added to the assembly
- Placement near bit
- Limited experience
- Difficult to quantify effect

Future use:
- Improve quantification (systematic testing)
- Milling operations

Table 19: Summary of vibration mitigation considerations in underreamer operations

Underreamer operations

Purpose:
Enlarge the pilot hole

Problem:
Generates high vibration levels

BHA design considerations:

- Bevelled edges
- Use with care, only use if needed
- Control bit aggressiveness
  - Less aggressive than the underreamer
  - Implement depth of cut control
  - Reduce the angle of the cutters relative to the formation
- Proper stabilizatiion
  - Stabilizer below underreamer
  - Expandable stabilizer above underreamer
- Select optimum BHA based on BHA design optimization software
- Anti stick-slip technology
- Frank´s HI tool