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New PDC Designs Doubles ROP on Kingfisher Project Well, Central North Sea

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Abstract

A focused Hughes Christensen application team (hereafter bit company) was formed to address the drillability problems and apply the latest PDC technologies to the 12 ¼" section of Shell Exploration's Kingfisher 16/8a-HP2 well in the Central North Sea UKCS **(Figure 1).**

The application team focused on the most demanding Kimmeridge / Brae sequence in the base 12 ¼" section. Two new bits were designed, built and run. Four other PDC bit types were also run in this section.

These innovative designs are part of a new product line that utilize improved stability, new cutter technology and optimized hydraulics to improve performance.

The new designs were used to drill a 1,642ft 12-1/4" hole section in 172.5 drilling hours compared to the nearest offset well that required 296 drilling hours to drill 1,696 ft of 12-1/4" hole. [1,2] The authors will document that the application specific designs delivered the lowest cost/ft in the field (US$467/ft) compared with the next best cost/ft of US$658. This equates to a 30% improvement over the previous best cost/ft in the field.[2]

Introduction

In 1999, Shell U.K. Exploration and Production on behalf of Shell U.K. Limited and Esso Exploration and Production UK Limited decided to drill an additional well in the Kingfisher field in order to optimize the production profile from the over-pressured Heather Sands reservoir. This second well, 16/8a – HP2, would be drilled from a nearby vacant slot, which had already been pre-drilled to the 20" casing shoe at 3407ft.

During the planning stages of 16/8a-HP2, great focus was placed on improving drilling efficiency relative to HP1. Offset performance data from the initial three Kingfisher development wells (BP1.1, BP1.2, BP2.1) was useful down to 13,000 ft TVD but HP1 was unique in the field with a targeted true vertical depth projected to reach 15,000 ft. [3]

From previous experience, it was determined that optimizing drilling efficiency in the 12-1/4" hole section was critical to project economics. Formations that proved particularly problematic in the 12-1/4" hole section of well HP1 included the abrasive Kimmeridge Clay and the hard and abrasive Brae Formation. The detailed planning of well HP2 was further exacerbated by the lack of wireline log data from well HP1 which seriously limited the ability to complete any rock strength analysis which may have helped to improve bit and cutter selection.

To achieve directional objectives in the 12-1/4" hole section, the operator needed to utilize steerable motor assemblies to hold angle at 22° through the Kimmeridge, Brae 1, and upper Brae 2 units. A build and turn in the lower Brae 2 and upper Brae 3 units gave a final inclination of 43° at 9 5/8" casing point.

The HP1 well **(Table 1)** was the closest offset well and the only well in the vicinity that drilled 12 ¼" hole through the hard and abrasive Kimmeridge and Brae. Two heavy set PDC bits sustained heavy wear after drilling only 218ft raising questions as to whether the formations were actually economic to drill utilizing PDC technology[1]. The remainder of the 12-1/4" section on HP1 was completed using Tungsten Carbide Insert bits but at a low ROP.

During the planning of this well it became apparent that the very latest materials, design and application techniques would need to be utilized to make a marked improvement to the well economics. The Bit Company was in the advanced stages of field testing new PDC designs that included improvements in cutter technology, stability and hydraulics. The combination of these two events led to cooperation between the operator's well engineers and the bit company's application and design engineers which produced two new PDC designs. This led to greatly improved performance when compared to both offset wells and same well bit runs.

Well Planning

The 12 ¼” section **(Figure 2)** was to be maintained on a 22.3° tangent at an azimuth of 156 ° through the Chalk, Valhall, Humber, Kimmeridge and the Brae 1, 2 and 3 formations. At 14,275ftMDBDF in the lower Brae 2, a build and turn was to be initiated at 2.7 °/100ft, to a final inclination of 43° and azimuth of 152° . A 150ft tangent section was planned prior to TD at 15,100ft. The objective of the 12-1/4" section was to isolate the troublesome Brae sequence and provide the formation strength required to drill the higher pressured (11,750psi) Heather Sands reservoir. The planned casing point was in the lower Brae 3, below the deepest Sand, which would leave formation strong enough to sustain the higher mud weights required for the Heather Sands.

- Kimmeridge Clay - Combination of very abrasive sandstone, subdivided into clean and siliceous units with local hard calcareous cemented zones interbedded with claystone and siltstone. - 2 PDC Bits heavily worn on HP1. (12,902-13,591)
- Brae 1 - Depleted sand that could be under pressured by up to 4000psi. Pore pressure estimated at 3750psi
- Brae 1,2 & 3 - All consist of intercalations of abrasive sand and claystones and silica cemented sandstone a combination that makes them very hard to drill. TD in Brae 3 below the deepest sand member. (Pore pressure 5400psi)
- Brae Interval 13,591-14,563 ft that was to be drilled with a Syn-Teq POBM, mud weight 580pptf. [3]

Bit / BHA selection was critical to well economics in this section. After careful consideration engineers decided the best approach would be to use low speed high torque mud motors to achieve the best possible penetration rate through the interval. Since high shocks / vibration had been seen in various offset wells, the use of mud motors was considered essential to provide de-coupling with the rest of the BHA[4,5]. A 5:6 lobe motor was the clear choice and the Drill Bit companies were tasked to come up with PDC designs that would give the maximum durability as well as meet the directional requirements.

Although Premium products were being offered from various bit manufacturers.. This application was far more demanding and required specifically designed bits to address the unique aspects of the application.

New 12-1/4" PDC Bit Designs

Two designs were developed for this application. Very early in the discussions between the team members it was established that two very distinct applications existed.

1. Kimmeridge – Brae 1 section – This presented the greatest challenge, as the offset performance tended to show this was economically incompatible with current PDC designs. Stability and abrasion resistance were perceived as key.

2. Brae 2 – Brae 3 – In addition to continued stability and abrasion resistance, the requirement of steerability was added to complete the build from 22° to 43°.

To aid in bit development, the team studied dull bit pictures available from previous Kingfisher wells. They also analyzed data from other well operations in the Central North Sea that contained hard abrasive formations. [1-3] From this extensive analysis, engineers determined that technology development already underway would be well suited to improve performance on the upcoming Kingfisher well.

Various advanced proprietary drill bit dynamics models[6] were extensively used to predict stability, wear rates, dynamic loading and hydraulic efficiency. These modeling techniques were invaluable in designing bits of the correct profile, cutter type and cutter size

HC609 – Developed for application 1, this design has 9 blades set with 19mm cutters. The cutter types used were chosen according to the position on the bit. Maximum gauge protection was utilized to ensure the bit stayed in full gauge. Nine Nozzles were fitted and hydraulics were further enhanced using Computational Fluid Dynamics.

HC408 – To address the steerability issues of application 2, an eight bladed 13mm cutter design was also developed. This bit was to have engineered cutter placement to combine aggressiveness with durability **(Figure3**). Particular focus was placed on the positioning of the BRUTES as they were expected to carry some of the primary loading especially in this application.

PDC Bit Development

These new PDC bits combine the very latest in advanced technology and a revolutionary design process to achieve maximum performance and consistency in defined applications. . The tools available to the bit development team were split into three areas of advanced technology. These areas or reservoirs of knowledge are:

- Advanced Stability
  Concentrating on , but not limited to, the resistance and reduction of lateral vibration commonly called bit whirl
- Innovative cutter technology
  Application Specific Diamond properties and thickness
  Application Specific external geometrys
- Computational Fluid Dynamics (CFD)
  Three-dimensional modeling of every new bit with regards to hydraulic cleaning efficiency.

Advanced stability

Once a cutter breaks or spalls, it wears very quickly. In some applications, operators continue to use the PDC bit even after breakage occurs to get the maximum life from the bit. They are hesitant to pull the bit until they know it is totally worn out. In this situation, the dull can indicate smooth wear but in reality the major dull characteristic was impact damage **(Figure 4).**

For impact damage to occur there must be an impact source and fragile cutters that cannot withstand these impacts[4]. There are two ways to address this issue: 1) develop a cutter that does not break or 2) modify the bit frame so it is less prone to vibration and does not subject the cutters to excessive impact loads
A key component of durability is the ability to resist whirl[7]. This controls impact loading on cutters caused by mild and severe vibration. Mild vibration causes minor chippage and accelerates wearflat development while severe vibration causes intense dynamic loading that leads to catastrophic impact damage.

From their studies engineers defined two types of stability:

1. Primary Stability: The tendency of a bit to drill smoothly or how fast the bit locks-in and becomes stable. In field operations this influences the amount of time the bit is operating in a stable drilling mode.

2. Secondary Stability: How severely the bit vibrates when it is unstable **(Figure 5),** which is related to its ability to resist drilling system instability. In field operations this influences the severity of dynamic cutter loads when the bit drills in an unstable mode.

Laboratory Stability Tests

The stability test procedure used on the bit development project involved increasing ROP in incremental steps and holding rotary speed constant at 120 RPM . The level of stability of a given bit was defined by how quickly it locked-in or drilled a gauge hole with a smooth bottom hole pattern in a particular rock type. During the research effort two types of limestone were used for testing: Bedford (a.k.a. Indiana) and Carthage **(Figure 6)**. Using two rocks instead of only Carthage allowed engineers to identify subtle differences that could not be observed otherwise.

Primary Stability

Primary stability is obtained through cutter layout. The state of the art PDC technology uses both high and low imbalance design strategies depending on the application.

High imbalance and low imbalance force modes of bit stabilization were considered for this application. With the high blade count requirement and abrasive nature of the formation it was quickly established that low imbalance force designs were appropriate..

Low Imbalance Force Designs
The goal of a low imbalance force design is to minimize the tendency to deviate from ideal motion (stable, on-center drilling). This design allows implementation of efficient cutting structures because it does not rely on rubbing or high side loading for stability. This bit design can also use maximum cutter density to provide durability[8]. However, the low imbalance design cannot overcome system instability.

A kerfing design is a special type of low imbalance layout that uses cutters that share the same radial position. This creates large grooves (a.k.a. "kerfs") in the bottom hole pattern that tend to keep the bit drilling on center. The restoring forces from the grooves provide some ability to overcome system instability.

Secondary Stability

A major new aspect of stability testing was documenting the level of load variation when unstable. We recognized that by taking certain steps vibration severity could be significantly reduced while in the unstable state. This improves durability by protecting the cutters from impact damage. This reduced vibration is advantageous to the entire BHA. Two new proprietary technologies for controlling secondary stability are discussed below

Lateral Movement Mitigator (LMM)
This provides a bearing that limits lateral motion when bits whirl. Although LMM limits radial deviation, it does not hinder performance ROP.

BRUTE Inserts
Another new external feature is BRUTE inserts (Backups cutters that are Radially Unaggressive and Tangentially Efficient). These cutters use a thick diamond table imbedded in a wear knot and are oriented so they cut tangentially, but not radially (sideways) . The polished diamond provides a low friction surface orientated to shear rock if the leading cutter is damaged.

Innovative Cutter Technology
There are basically three different factors to consider when discussing cutter technolgy.

1. External Cutter Geometry & placement
2. Internal Cutter Geometry - Interface design
3. Cutter size & profile

External Cutter Geometry
Cutter backrake (BR) strongly influences impact resistance and generally varies between 0° to 30°. The higher the degree of BR, the greater the cutter's resistance to fracture. For example, when impact occurs, energy is directed into the carbide substrate instead of along the diamond table decreasing the likelihood of spalling and catastrophic failure

The team had highlighted that abrasive wear was the main criteria for failure, but remembering that these bits may be run on an AKO motor the resistance to impact damage was also important. After further research and testing the team realized that as the cutters wore then the efficiency of that cutter to cut rock changed. Furthermore cutters with differing back rakes wore at differing rates and in fact as the cutter wears the efficiency of the higher backrake drops off slower than that of a lower backrake cutter. **(figure 7)**

Internal Cutter Geometry
Diamond table thickness varies to obtain a balance between durability and efficiency, and the interfaces are engineered to provide optimum performance with the table thickness used.

The diamond/substrate interface strongly affects impact resistance. The geometry of the underlying carbide affects the residual stresses from the manufacturing process. These residual stresses influence initiation and propagation of cracks that cause cutters to spall and catastrophically fail[9]. **(Figure 8)**
Cutter Size and Bit Profile

From previous studies[10] it is understood that more diamond volume will lead to increased durability for a given design. However, with the advent of new PDC cutter technology care must be taken to ensure that selection of very thick diamond cutters does not result in an inefficient cutting action due to high WOB requirement. The mode of wear for a given application must be understood before a customized design is warranted.

To understand the wear profiles better, engineers set up a number of simulations consisting of differing bit profiles, cutter sizes, blade count, cutter chamfer angles etc. and studied the wear profiles and Torque / WOB requirements to drill at a constant ROP in a generic hard abrasive sandstone. From this analysis, an optimum bit profile was chosen which would offer the opportunity of giving the maximum diamond volume in the area of heaviest abrasive wear[6].

The test shows that for a given bottom hole condition under exact parameters an 8 bladed 19mm cutter bit will drill further than a similar 13mm cutter design. **(Figure 9,10)**

In detail, the 13mm design has a total of 82 x 13mm cutters and the 19mm design has a total of 54 x19mm cutters plus 11 x 13mm cutters. Running the wear model until each bit has reached 30% wear on any one cutter the 19mm design does indeed drill further. Simple math's show that this should be no surprise since the 19mm design has over 42% more diamond volume across the face. , Continuing the studies, by adding 28 backup cutters on the 13mm design in the high work or power area as shown by Dysktra et al. [6]. Diamond volume in this area still showed the 19mm design to have 30% more diamond volume and thus allowing the 19mm design to drill further..

Further analysis concluded that although adding back up cutters did indeed add diamond volume, in the worn state these back up cutters reduced the effeciency of the design. After a brief reduction in WOB requirement, the added diamond volume on the bottom of the hole (increasing with abrasive wear) left a final WOB requirement of 54klbs against an 8 bladed 19mm cutter design with a final WOB requirement of 43klbs. Analysis shows that at the 30% worn state the 13mm design will have a 22% greater foot print on formation than the 19mm design.

In addition once both bits reach 30% worn, the 19mm design will still have more useable diamond volume compared to the 13mm design.

The wear model analysis provides a sound foundation for bit selection under smooth drilling parameters. Since vibration related bit damage was expected, dynamic load prediction modelling was carried out to allow further design optimisation[9].

With the cumulation of over two-year intense cutter development program the Team were fortunate in that they had five advanced cutters to choose from. Each cutter has unique characteristics, which can be linked to the differing loads on a profile of a bit (These characteristics are beyond the scope of this paper). Those cutters can be dialed in to locations on the profile to optimize the bits performance.

From this application specific analysis a 19mm cutter PDC bit was to be designed for application 1. For the second design it was understood that the formations were not as abrasive and compacted as the Kimmeridge and Brae 1. The operator had also expressed the need for some steering to be done in this area. With this in mind an 8 blade 13mm bit was also designed and built.

Optimized Hydraulic Efficiency

Recent advances in the application of CFD[11] to optimize the hydraulics of PDC drill bits has allowed engineers to use the process in conjunction with the new designs. Initially, the process of meshing the model and optimizing the hydraulics of a bit using CFD would require up to one month to complete. Now with faster computers, new meshing techniques, automated data analysis and new findings in the applications of CFD to PDC drill bits, the time required to complete the CFD process has been reduced. Although with the many new enhancements applied to the new bit line it is difficult to isolate those benefits due solely to the CFD analysis, the new hydraulics optimization method most certainly contributes to better cleaning, cooling and reduced erosion. Case studies show the new bits drill faster and farther.

Both of the new designs were subject to CFD analysis for a specific set of parameters. The operator provided the Bit Company with the mud details, pump pressure limitations, RPM & flow rates they expected to use for these formations so that the two bits could be fully optimized for improved particle residence time and reduced erosion effect.

Performance Summary

The base plan was to drill the section with another manufacturers nine bladed PDC bit consisting of different sized cutters[1]. However, after only 50 ft drilled in the mid/base Kimmeridge the bit came out very heavily worn and ¾" under gauge indicating the Kimmeridge was more abrasive than had been assumed.

After seeing the condition of this PDC design it was certainly felt this was the right time to try the new designs. Two of the new development bits were used in the upper Brae sequence. Both of these bits did well and provided a step change in performance and durability in this very tough formation. The remainder of the Brae sequence to casing point was drilled with more 'standard' type bits.

Throughout the Brae sequence the use of motor drilling had a beneficial impact on drilling economics. On bottom drilling times were much better and the motor provided an excellent de-coupler for the string and helped to keep impact to the BHA at a minimum. Additionally, the continued use of a drilling optimization system kept a very tight control on drilling parameters and tool durability. The optimisation system delivered real time monitoring of ROP, HKLD, DEPTH, SWOB, DWOB, STOR, DTOR, RPM, ECD, SPP and more crucial from a bit point of view was Lateral and Torsional shocks. The fact that the entire interval was drilled without a single tool failure is testament to the effectiveness of the system management.

One of the other major risks for the drilling phase was the potential for differential sticking and/or fracturing of the, potentially, heavily depleted Brae 1 formation (3700 psi depleted). Mud Rheology and ECD levels were constantly monitored throughout and no problems whatsoever were seen while drilling the section.

Initially the chalk was drilled with a 550 pptf mud which was low enough to optimize drilling performance without leaving too large a step up to the 580 pptf required for the lower formations in the section. This higher mud weight was required to manage inherant formation instabilities within the Cromer Knoll and Kimmeridge formations. This led to the focus on overbalance and ECD management for the Brae 1. However, the 580 pptf was well below the currently accepted well bore stability model for the area which estimated a mud weight of 620 pptf, further increasing the potential risks while drilling. It was only after lengthy discussions with the main operator in the Brae region, that enough confidence was gained to drill with this section with a 'lower' mud weight.

BHA run 6 and 7

Following a good run through the Chalk interval a six bladed PDC bit was pulled at 13,486 ft after drilling 251ft of Kimmeridge Clay. The bit was graded 4-8-WT-S-X-I-HC-BHA. Another manufacturers PDC bit (AMPDC1) was chosen for the following BHA due to the good offset performance. This bit was a nine bladed design that used different size cutters. This bit drilled a total of 49 ft to 13,535 ft before being pulled 13/16" under-gauge. The ROP over the run was generally 8-12ft/hr but dropped off rapidly to 1 ft/hr. WOB varied between 25-40k. The bit was graded 2-8-WT-G-X-13/16-LT-PR.

	Footage	%	Hrs	ROP
Total	49	100	11.7	4.2
Rotate	49	100	11.7	4.2
Orient				

Max WOB	Av. Torque	RPM	Flow	Max Pressure
40	5-17 kftlbs	60	770 gpm	3150 psi

BHA run 8

The new HC609 design was chosen to have a second (and probably last) attempt at drilling these formations with PDC bits. The BHA was left virtually the same as the previous run with a 5:6 lobe 9-5/8" XP motor (0 Deg Bend), TRACS Tool, the 12-1/8" sleeve stabilizer was changed out for a 12-3/16"rotating near bit stabilizer. Due to the added stiffness of this new assembly, the BHA hung up at 9,590 ft and the assembly had to ream down to bottom at 13,535ft. ROP initially was 10-15ft/hr with 20-40k WOB being required. The top Brae 1 was picked at 13,591 ft. Brae 2 at 13,755. At 13,850ft it was decided to POOH due to an increasing drop tendency from 0.4 to 1.5 Deg/100ft which was deemed unacceptable as correction runs would have proved slow and problematic. Torsional vibration was relatively low throughout the run..
On surface it was found that the near bit stabilizer was 7/32" undergauge. The bit was still in good condition and was graded 4-7-WT-S-X-I-HC-BHA. Some minor chipping (4 cutters) and partial diamond delamination (3 Cutters). Partial Delamination was also seen on the PDC Inserts mounted on the shoulder area.

Diamond loss was mapped out across the profile of the bit. The graph shows **(Figure 11a,b,c,d)** the relative percentage diamond loss and, when used in conjunction with the application notes, is useful information for determining whether the bit was suitable for the application.

- HC609 diamond loss map follows the wear model almost exactly indicating accurate wear prediction.
- Very little chipping of cutters (This was a major concern prior to drilling the section) showing good vibration suppression.
- Maximum 60% Diamond loss after 395ft of the most challenging interval.

	Footage	%	Hrs	ROP
Total	395	100	30.0	13.2
Rotate	395	100	30.0	13.2
Orient				

Max WOB	Av. Torque	RPM	Flow	Max Pressure
40	5-17 kftlbs	40	770 gpm	3250 psi

BHA run 9

Due to the increased confidence in the new designs, the second custom design bit (HC408) was picked up on a steerable motor assembly to initiate the build and turn required before casing point. A 1.22 bend was used in conjunction with a BHA designed to give a strong rotary build tendency . This bit drilled a total of 507 ft of Brae 2 to 14,437 ft at an average ROP of 12.1 ft/hr. WOB through this run reached 55k with ROP as low as 2-3ft/hr and as high as 40-55 ft/hr through the shale sections. Sliding was extremely difficult with weight transfer being the major problem. Build rate decreased from the initial 1.0 Deg/100ft to less than 0.6 Deg/100ft. Up to 70k overpulls were encountered after sliding which indicates severe ledging in the hard sands. The bit was finally pulled for low ROP and graded 4-8-RO-S-X-3/16"-BT-PR, the sleeve stabilizer was also 3/8" undergauge that would explain the drop in rotary build tendency. HC408 showed slightly higher shocks than the HC609 but these were easily controlled by altering RPM. The dull condition makes it impossible to speculate how much this impacted the overall bit performance. **(Figure 12a,b,c,d)**

	Footage	%	Hrs	ROP
Total	507	100	42.0	12.1
Rotate	471	93%	37.9	12.4
Orient	36	7%	4.0	8.9
Max WOB	Av. Torque	RPM	Flow	Max Pressure
55	5-17 kftlbs	40	770 gpm	3250 psi

BHA run 10

With the success of the two custom designs, the operator was keen to continue using the new technology. A bit manufactured for a tough steerable application was brought in from Norway to meet this need. Although not designed specifically for the Brae, the features of the bit were considered the best available option. The bit was an eight bladed 19mm cutter design, again utilizing the new cutter types. However, it did not incorporate all the new stability technologies that were used on the previous bits HC609 and HC408. Sliding was markedly easier than on BHA 9 and ROP achieved a maximum of 10-15ft/hr. Significant overpulls were again encountered after a slide. The Brae 3 was picked at 14,563 ft with ROP remaining low. Drilling continued to 14,820 ft when the bit was pulled for low ROP. Bit Grade was 3-8-RO-N-X-2/16”-BT-PR.

This BHA run showed higher torsional shocks, than from previous runs, which were not cured by altering drilling parameters. Only by drilling in the Slide mode was any improvement noted. The reduced footage, ring out on the nose of the bit and heavy cutter spalling / breakage are all textbook trademarks of Stick Slip vibration[5]. From the diamond loss mapping, no smooth wear profile seen across the radial distance, this indicates that the main mode of cutter failure was vibration related. **(Figure 13a,b)**

	Footage	%	Hrs	ROP
Total	383	100	47.7	8.0
Rotate	308	80%	38.5	8.0
Orient	75	20%	9.2	8.2

Max WOB	Av. Torque	RPM	Flow	Max Pressure
50	9-15 kftlbs	40	770 gpm	3100 psi

BHA run 11

Due to lack of availability, no more suitable new bit designs were run. A nine bladed bit similar to that used on BHA seven was run on a steerable motor assembly with 0.78 Deg Bent Housing. Drilling varied at between 2-20ft/hr. ROP dropped to 1ft/hr at 15,013 after drilling 193ft. ROP over the interval averaged 7.4ft/hr. Bit grade 3-8-RO-S-X-1/16”-CT-PR with the motor sleeve 3/16” undergauge.

	Footage	%	Hrs	ROP
Total	193	100	26.2	7.4
Rotate	193	100	26.2	7.4
Orient				

Max WOB	Av. Torque	RPM	Flow	Max Pressure
45	5-13 kftlbs	40	770 gpm	3340 psi

BHA run 12

A conventional eight bladed PDC bit (BD447) was picked up and drilled the final 115 ft to TD at 15,128 ft. Average ROP was 8.6ft/hr and the bit was graded 1-4-WT-A-X-1/16”-HC-TD.

	Footage	%	Hrs	ROP
Total	117	100	13.6	8.6
Rotate	117	100	13.6	8.6
Orient				

Max WOB	Av. Torque	RPM	Flow	Max Pressure
25	5-18 kftlbs	40	825 gpm	3650 psi

Cost per Foot Calculation

Bit performance is ultimately evaluated in cost/ft, for all bits used in the interval discussed. The cost/ft is also shown for HP1 to show the performance improvement possible with application specific PDC drill bit technology. **(Figure 14)**

$$Costperfoot = \frac{DrillingCost + TripCost}{Footage}$$

Operating Cost per hour = $4,200
Drilling Cost = Operating Cost x Drilling Hours
Trip Cost = Trip Time (1hr/1000ft) x Operating Cost

Since all bits run through this section were on similar BHA's and at similar drilling parameters, RPM (117-137), Flowrate (770gpm) and standpipe pressure (3100-3340psi), it was considered a good benchmark to evaluate the new technology bits. **(Figure 15)**

Conclusions

- The cross functional team approach of engineers from operator, Directional drilling company and bit manufacturer will give enhanced performance and show substantial savings.
- Enhanced PDC bit stability, cutter technology and optimal hydraulic efficiency can give a step change in performance when applied correctly
- The use of advanced wear and dynamic models, tailored to a specific application reduces costly iterations and offers a more effective solution to PDC bit design
- Drilling system optimisation services will extend tool life and improve overall performance in tough applications.
- The use of real time down hole vibration measurement allows optimization of drilling parameters to improve performance **(Figure 16)**

Nomenclature

BHA = Bottom Hole Assembly
PDC = Polycrystalline Diamond Compact bit
ROP = Rate of Penetration (ft/hr)
RPM = Revolutions per Minute
WOB = Weight on Bit (Klb)
GPM = Gallons per minute
PSI – Pounds per Square inch
AMPDC – Another Manufacturers PDC

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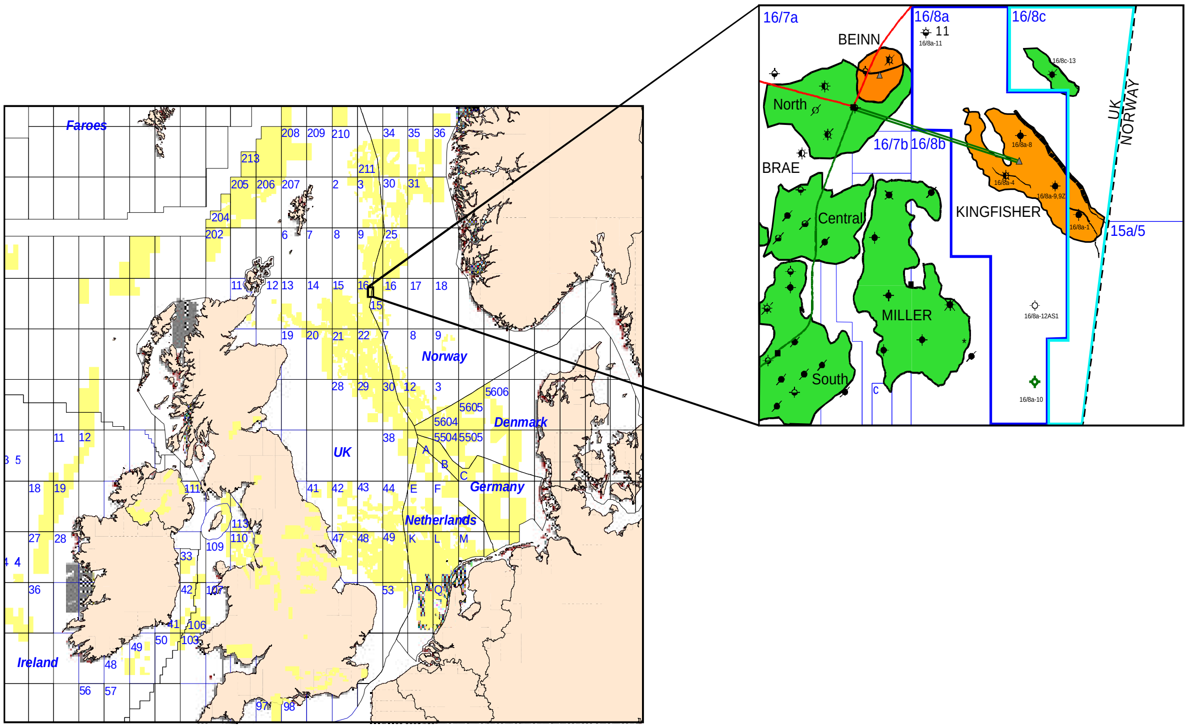


Fig 1: Kingfisher Field Location Map

Bit Type	Depth In	Depth Out	Drilled	Drilling Hours	ROP (Ft/Hr)	RPM	WOB (Klbs)	Inc Deg	Azi	I	O	MD	L	B	G	OD	RP
PDC 1	13500	13584	84	21.4	3.93	195	41	28	160	8	8	RO	A	X	I	LT	PP
PDC 2	13584	13718	134	38.9	3.44	195	44	28	160	4	8	RO	S	X	I	HC	PR
TCI 1	13718	13926	208	36.2	5.75	95	48	28	159	3	4	CT	A	F	1/16"	ER	PR
TCI 2	13926	14398	472	79.2	5.96	92	53	26	159	4	7	BT	A	E	I	LT	PR
TCI 3	14398	14894	496	62.8	7.9	88	58	34	159	3	5	LT	M	E	I	ER	PR
TCI 4	14894	15196	302	58.1	5.2	71	56	36	159	3	4	BT	A	E	I	LT	TD

Table 1: Bit Record Details from nearest offset well 16/8a-HP1 (Bits listed are for the Kimmeridge to Brae 3 sequence)

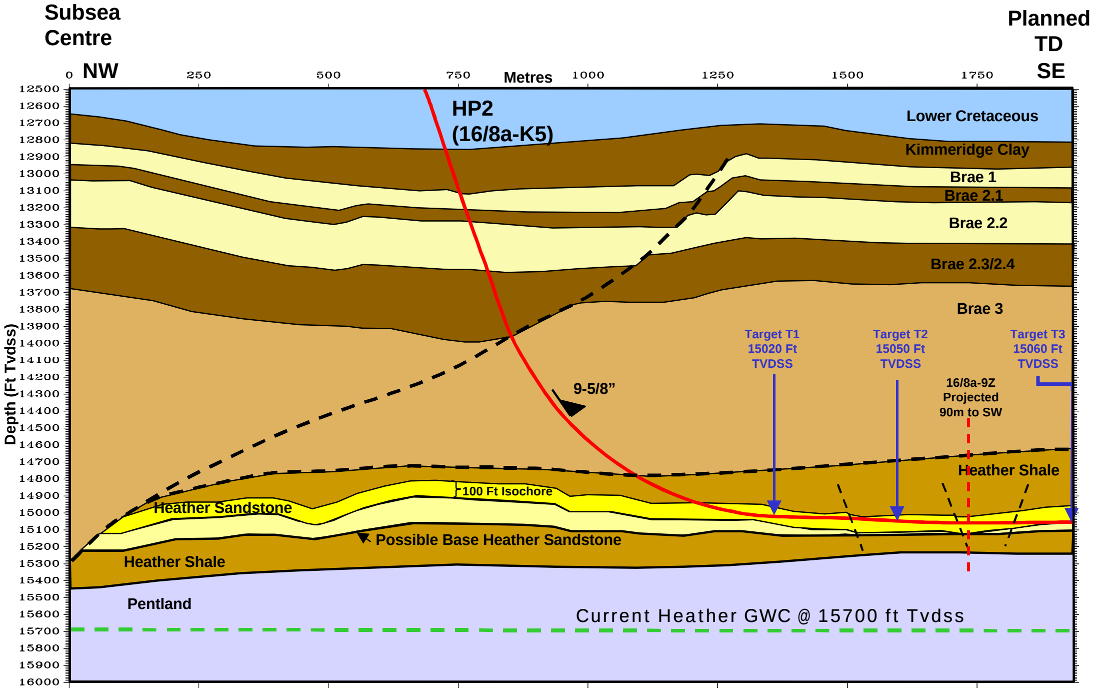


Figure 2. Geological Cross-section along 16/8a-K5 (HP2) well trajectory

Figure 3 State of the art Application Specific Cutters

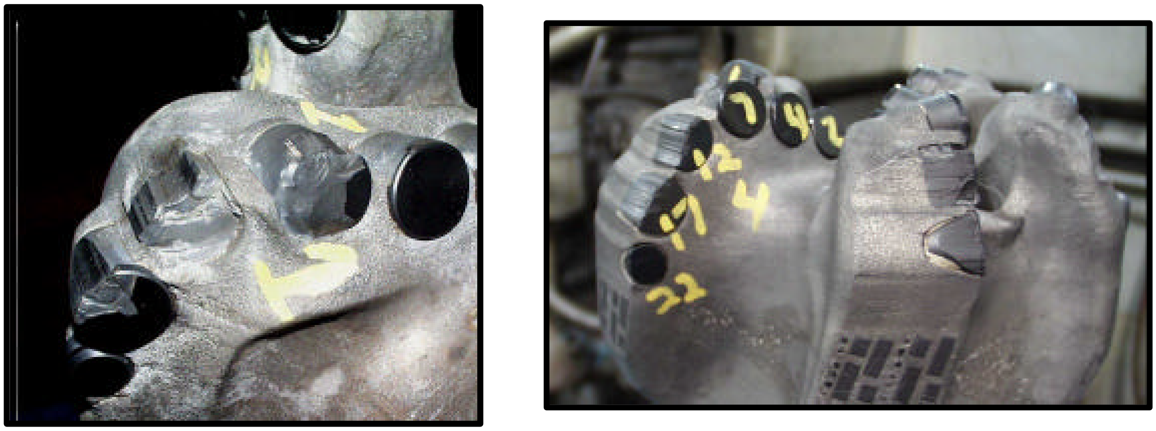


Figure 4. Dynamic and smooth wear of PDC cutters

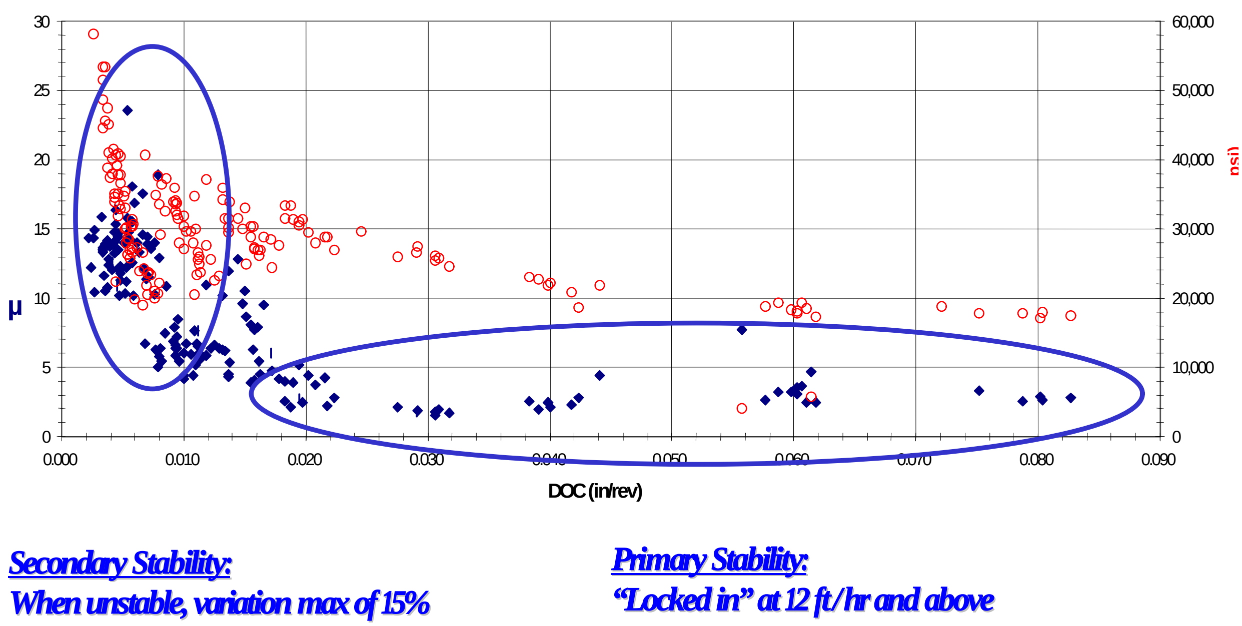


Figure 5. Graphical measurements of secondary and primary stability

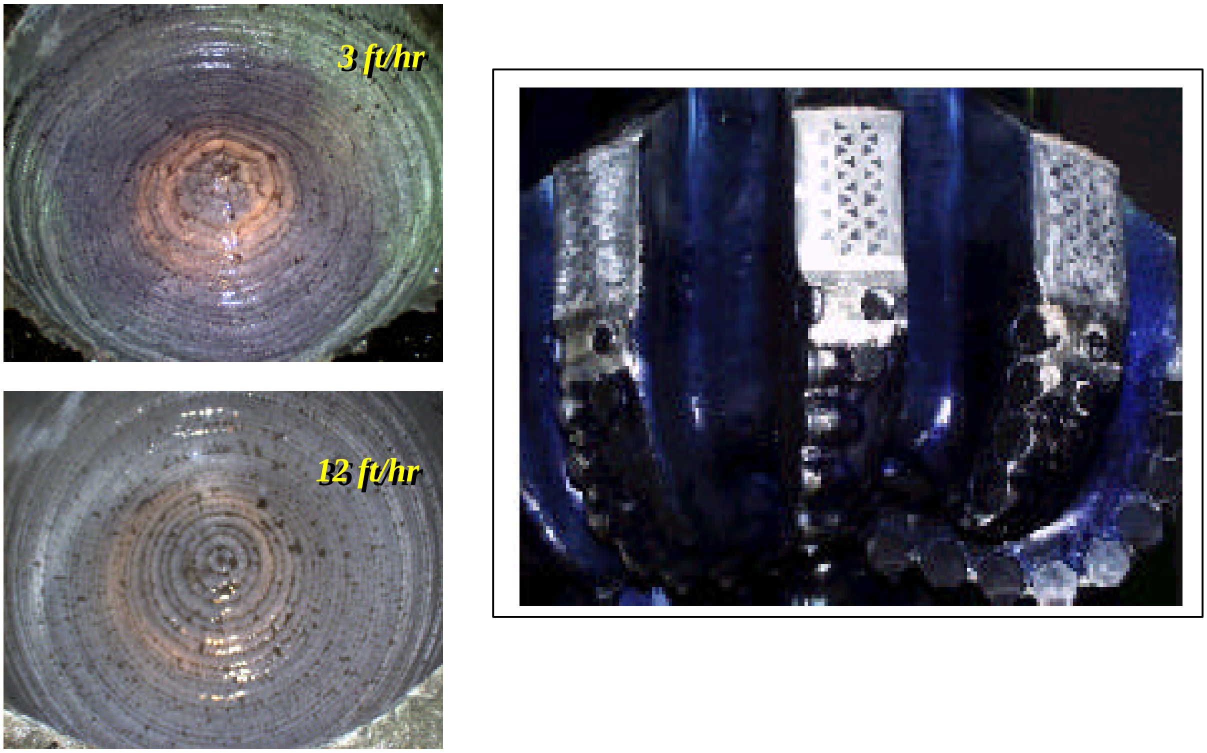


Figure 6: Carthage Bottom Hole Patterns and stability tested HC609 design

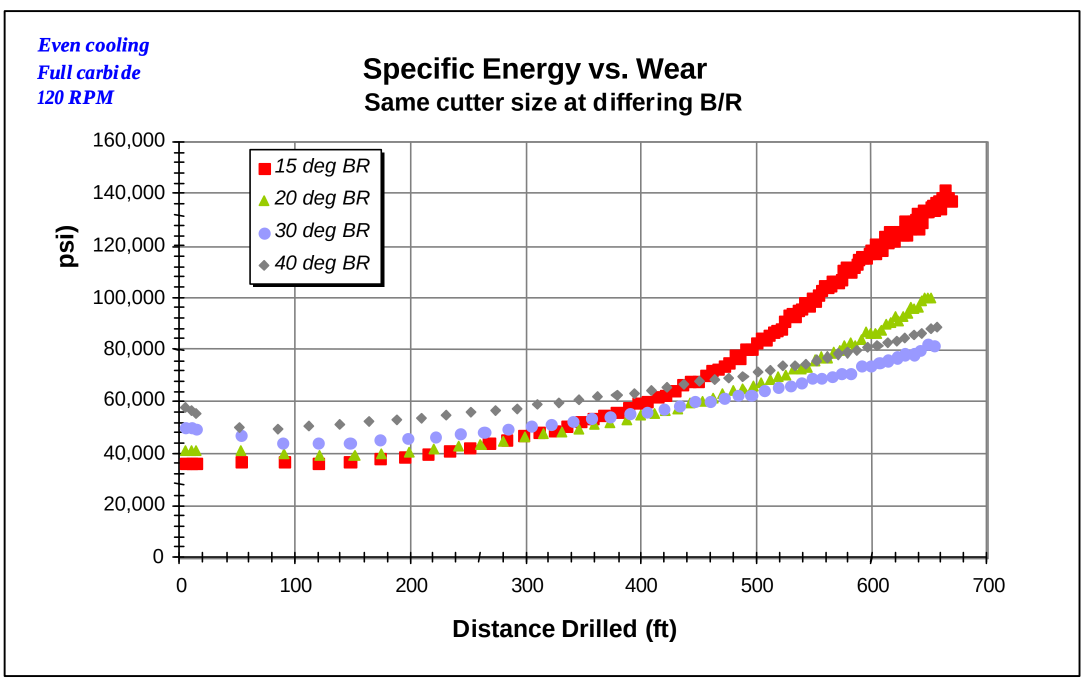


Figure 7: As cutters wear the higher Backrakes wear more slowly

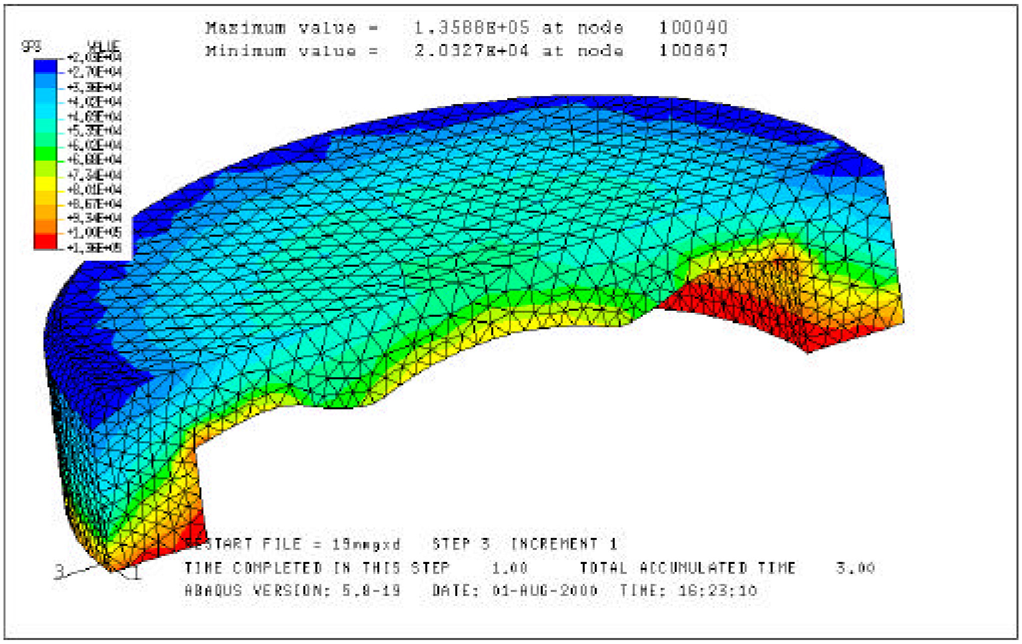


Figure 8. Variance of internal residual stress throughout the diamond layer

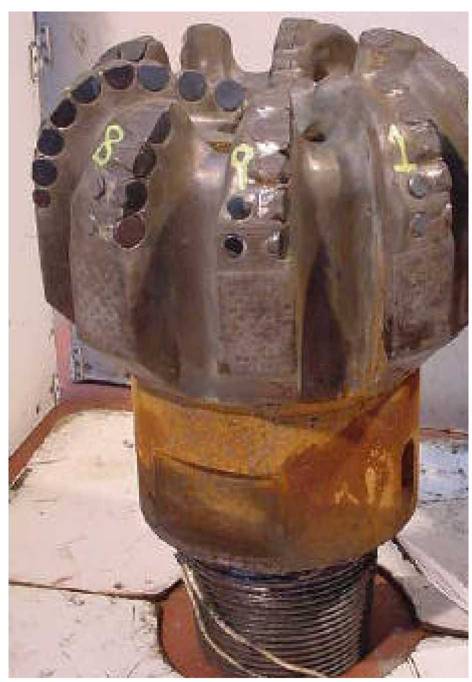


Figure. 11a: *: HC609 in new condition

Figure 11b HC609 dull condition

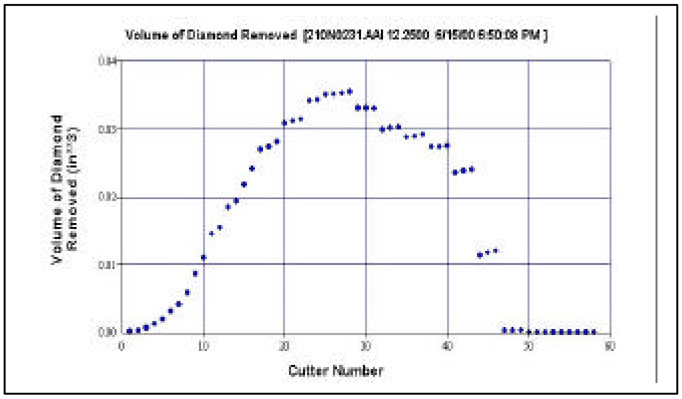


Figure 11c. Predicted wear pattern from wear model

Figure 11d. Actual wear from dull analysis

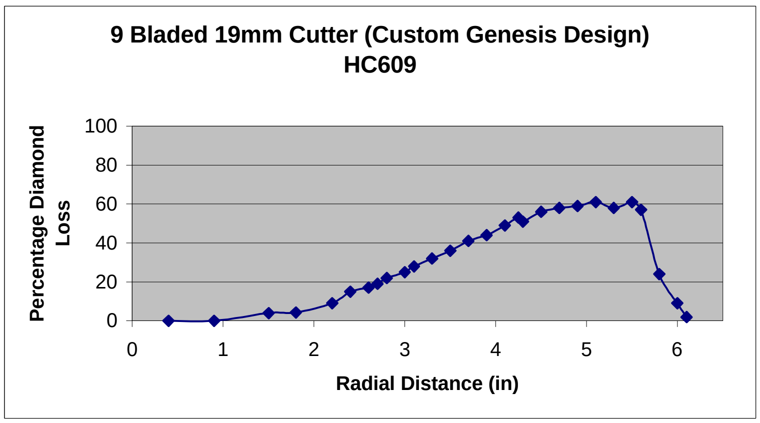


Figure 12a.: *: HC408 in new condition

Figure 12b. HC408 in dull condition

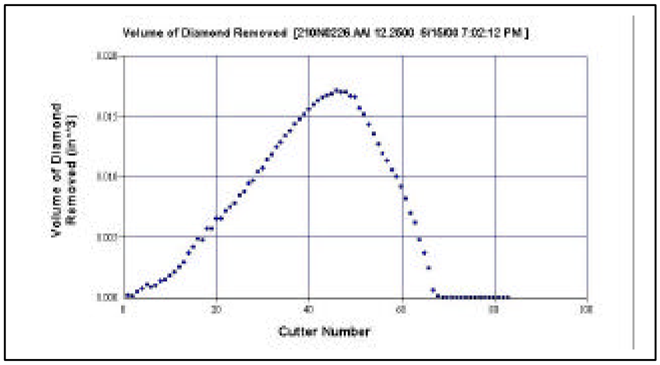


Figure 12c. Predicted wear pattern from wear model

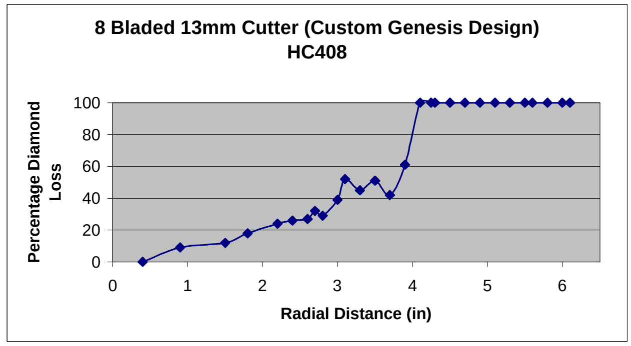


Figure 12d. Actual wear from dull analysis

Figure 13a. BD548 in Worn state showing signs of
classical stick slip[5]

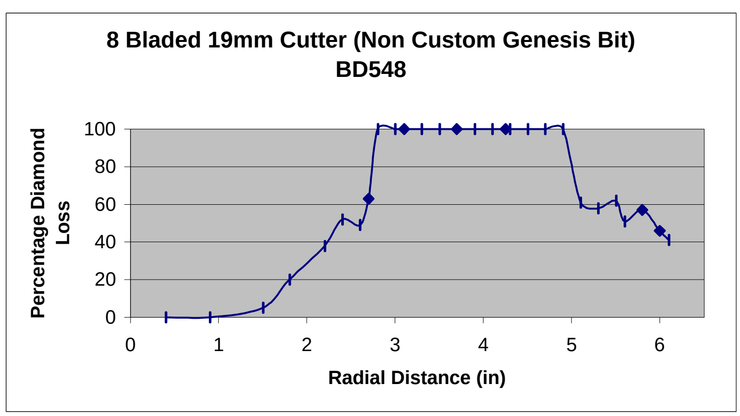
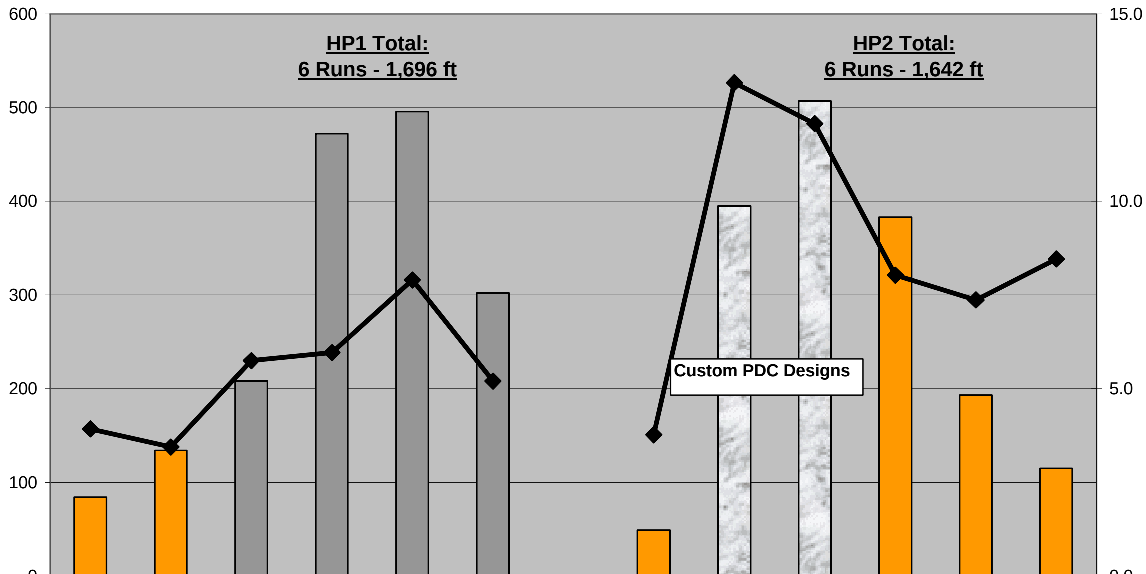


Figure 13b. Actual wear from dull analysis



	PDC 1	PDC 2	Insert Bit 1	Insert Bit 2	Insert Bit 3	Insert Bit 4		AMPDC1	HC609	HC408	BD548	AMPDC2	BD447
Feet	84	134	208	472	496	302		49	395	507	383	193	115
ROP	3.9	3.4	5.7	6.0	7.9	5.2		3.8	13.2	12.1	8.0	7.4	8.5
Cost/Ft.	$1,749.20	$1,649.22	$1,012.16	$832.86	$657.89	$1,019.35		$2,274.43	$467.10	$467.53	$685.60	$896.86	$1,049.20
DepthOut	13,584	13,718	13,926	14,398	14,894	15,196		13,535	13,930	14,437	14,820	15,013	15,128

Figure 14. HP2 performance and comparison with HP1

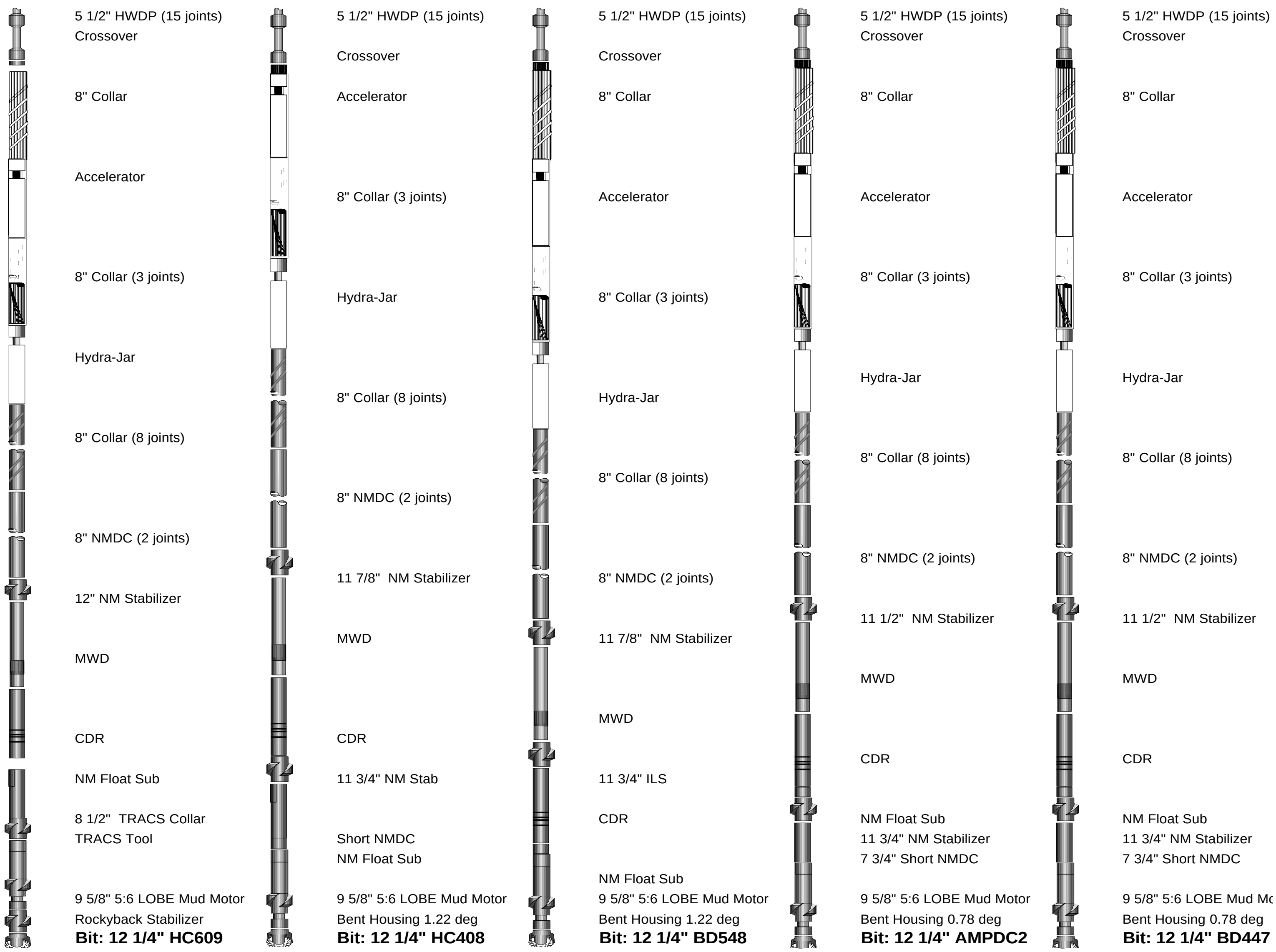


Figure 15. Bottom Hole Assemblies for BHA runs 8, 9, 10, 11 and 12

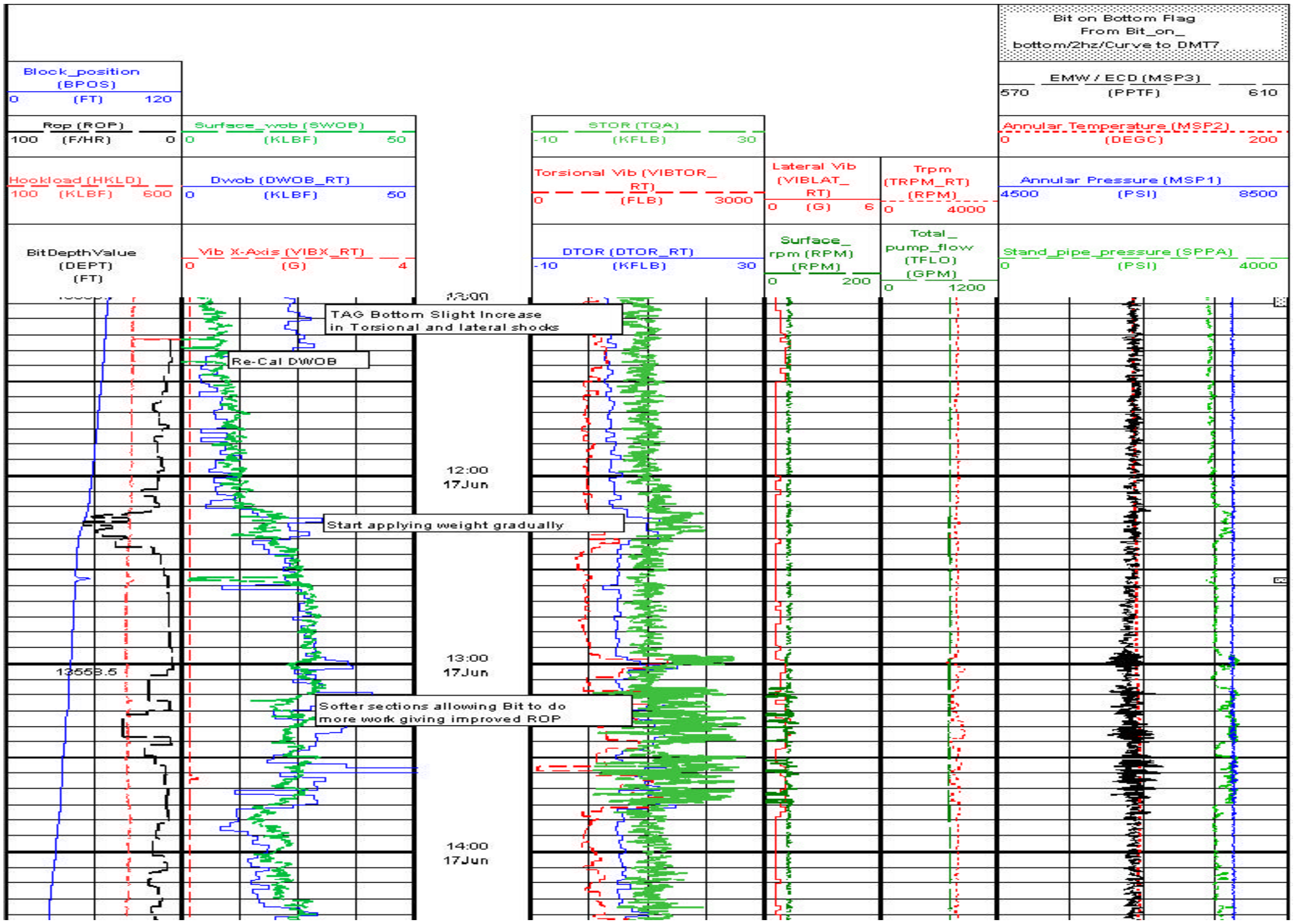


Figure 16. Real time vibration log with combined drilling parameters