Formation Related Drilling Difficulty and Possible Ways to Improve Drilling Performance – Deepwater-02 Well Case Study

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ABSTRACT

As we drill deeper, the tendency to encounter formations that are difficult to drill increases. It is therefore important to proactively identify and characterize these types of formations and put in place appropriate measures to overcome the drilling difficulty that this presents. Inability to proactively identify these formations and select appropriate bit and optimized drilling practices may lead to down time, increased well costs, or even inability to achieve geological target objectives. The essence of this paper is to do a post mortem of Deep water-02 well and draw inferences that would help improve drilling practices and optimum bit and reamer selection for future wells. The well log and drilling data within the well section with drillability challenges were analyzed using the appropriate well log data and drilling parameters; geological and mechanical properties were established, and trends were observed. The environment of deposition of these difficult-to-drill formations were weakly confined channel systems with a mass transport deposit system characterized by formation heterogeneity. These heterogenous formation are difficult to drill and cause a lot of damage to bit and reamers leading to increased hole section runs. The traditional thinking that rock hardness and abrasiveness contribute more to drilling difficulty is challenged as rock heterogeneity is seen as the primary contributor to drilling difficulty. In order to mitigate the negative effects of rock heterogeneity and other factors that contribute to drilling difficulty, a good understanding of the rock and drilling mechanics is more effective than just changing the bits. Recommended best practice will be to identify hard and heterogeneous formation at depth in offset wells and develop a bit selection and operational plan across these intervals based on a robust formation drillability analysis.

Keywords: Drilling, Deepwater, Formation Drillability, Mechanical Properties, Rock Hardness, Bits and Reamers, Environment of Deposition.

INTRODUCTION

Deepwater-02 was designed as a vertical exploration well with 3 target intervals; Shallow objectives in the 14.8 through 18.7MY, Deep 1 objectives in the 20.52 through 32.0MY and Deep 2 objectives in the 33.3 through 50.02MY sequences. The surface location is approximately 6,594' of water depth. The primary objective of the well was to evaluate the resource potential within the Upper Miocene – Lower Eocene inverted basin. Deepwater-02 was designed to verify the presence of the sands stated above and will be the first exploration well on the Deepwater 3 structure. The well was planned to be drilled using five casing strings (36" x 20" x 13-5/8" x 11-3/4" x 9-5⁄8") with contingency 16" liner depending on casing seat tests and pressure regimes. Figure 1 shows the well summary and objectives.

The 14-3/4"X 17-1/2" hole section under study required two bit runs to drill ~2,940 ft interval as per plan. This was based on bit performance data from offset wells. Review of data suggests that this bit design has been aggressive with good ROPs. However multiple bit runs were required to drill the hole section to TD.
There was an observed significant drop in ROP as drilling progressed and on trip out to change BHA, damage to both bits and the under-reamers were equally noticed (Figure 2).

A total of four bits and four reamers runs were required to drill this hole section. Open hole caliper log revealed under gauged hole intervals in the hole section. Additional hole opening runs were required to achieve the hole size. This added additional 17 days and $21MM to the project schedule and cost respectively.

There are several methods prevalent for bit selection, such as Cost per foot method, Dull Bit Grading method, Offset Bit Record method, Specific Energy methods etc. The commonly used criteria for selecting the bit for the next interval is the bit type with the highest ROP or the bit with minimum Cost per ft. In addition, factors such as hydraulics, formation hardness, bit design, and

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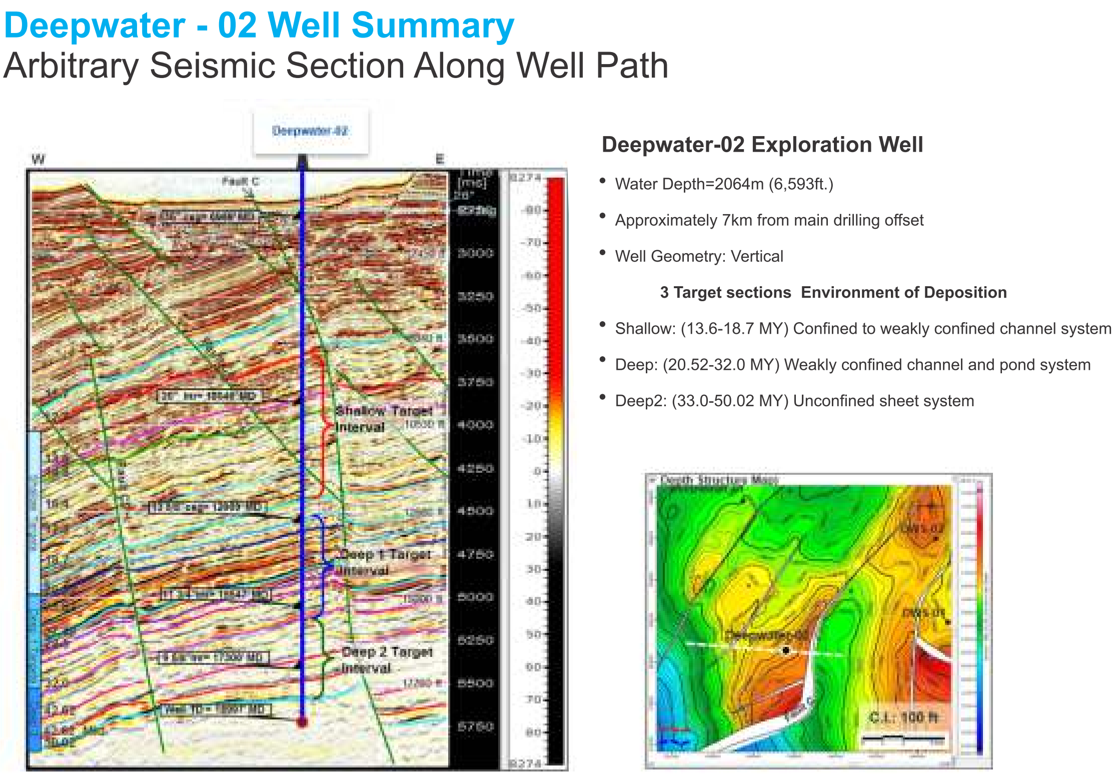

Figure 1: Well Summary Data.

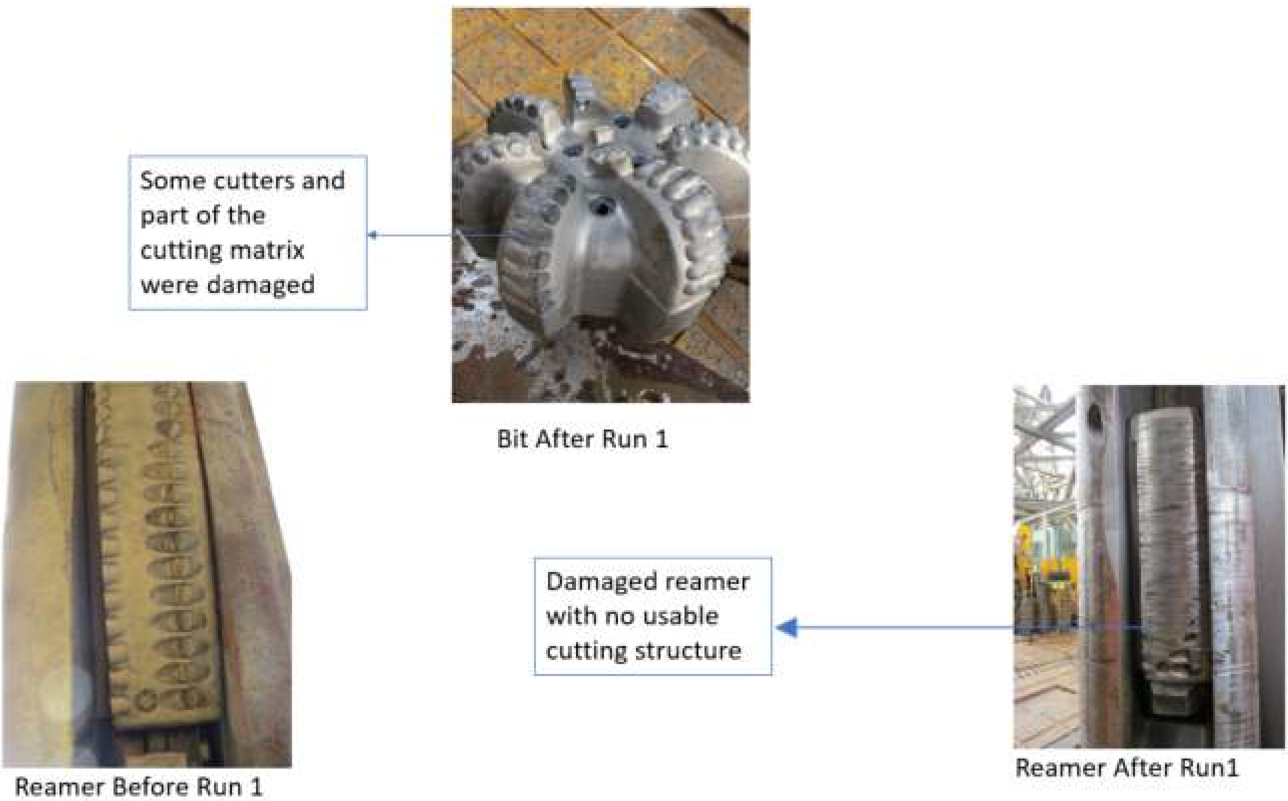

Figure 2: Pictures of bits and reamers before and after Run1.

operational parameters are considered in the selection process. Due to the number of variables considered, the selection process is a trial and error procedure. In many cases, this approach can ignore some of the important parameters affecting the bit performance and cannot guarantee selection of the optimum bit type.

The problem with using Offset Bit Record method is that they contain no lithology or strength information. Bit records indicate only how the bits performed over the intervals drilled and under what conditions they were operated. All these methods, in-fact reflect the bit capability i.e. individual bit's efficiency to drill a formation and not the formation drillability. Thus a bit selected on the basis of above methods will only give an idea about the performance of selected bit with respect to previously used bits. Formation drillability analysis is an approach that considers additional mechanical and geological properties to determine how the formation contributes to drilling difficulty.

Hole Section 14 ¾" x 17 ½" BHA Planning

A Rotary Steerable System (RSS) with concentric under-reamer as a single pass drilling application was chosen for this hole section. The directional suite has all the LWD/MWD complements. The 14-3/4" PDC bit is a 7-bladed matrix body with 16" cutter size designed with highly specialized directional features. The bit is also qualified to be stable and produce less torque and stick/slip in transitional drilling. Review of data suggests that this bit design has been aggressive with good ROPs.
The under-reamer selected for the project is a 17 ½" outer diameter (OD) concentric expandable reamer with ball-drop mechanism that activates the cutter blades, which are deployed with fluid circulation and deactivated when circulation is stopped. This design eliminates premature triggering independent of WOB, flow, or BHA pressure. The reamer is planned to use the StaySharp cutter technology to enable ream while drilling hard formations.

Hole Section14 ¾" x 17 ½" Execution Phase

The 14 ¾" x 17 ½" UR BHA was picked to drill out 16" casing float and performed casing shoe test. The reamer was mechanically activated below the 16" casing shoe by dropping a ball through the drill string. The section was drilled ahead with 14 ¾" pilot hole and reamed to 17 ½". The section was drilled making four bit and reamer runs.There was a significant level of stick slip vibration in all the runs.

METHODOLOGY

Well data within section that drillability challenges were observed. Data analyzed included:

- Gamma-Ray logs
- Resistivity
- Density
- Sonic logs
- Caliper logs
- Mudlogs
- Drilling reports
- Biostaratigraphic data

The Geolog petrophysical software alongside Microsoft excel was used in processing the data. These two softwares aided in presenting our results in different visualization formats from which inferences could be drawn. The well data underwent quality control to ensure that data was accurate using the different quality control tools available in both softwares. The Gamma ray and Mud log data was used to delineate the rock types and their characteristics-in addition to showing the rock types, the mudlog report gave a visual description of the formation as seen at the wellsite. Drilling parameters from the mudlog ASCII file provided a lot of useful downhole information. The resistivity log served as a complement to the Gamma ray and served as the fluid indicator of the formations. Unconfined compressive strength (UCS) and Porosity logs are derivatives of the sonic and density log respectively. Biostratigraphy data provided information about the age of the formations being analyzed. Key operational information for the benefit of the study were extracted from the daily geological and drilling reports and presented with the rest of the well data so that interpretations could be made.

DATA ANALYSIS, RESULTS AND DISCUSSIONS

Run #1: 11,965' -14,268'MD- 2,303' total footage

The planned bit was run with the reamer which has cutter blades fitted with Phoenix cutters (designed for medium hard formations). The bit and reamer for this run came from different vendors. The early Miocene sands, with shale intervals in between the sands, were drilled on this run. Drilling parameters were varied to stay within the stable operating windows of Weight on bit (WOB), Rotational speed of the bit (RPM) and Torque.

We begin to observe a downward ROP trend after drilling through the early Miocene heterogeneous interval (11,960'-12,660') (Fig 3a). Mudlog cuttings description put the cuttings percentages as 30% shale, 20%siltstone and 50% sandstone, the shales were moderately hard, siltstone was moderately indurated, and the sandstone was fine to medium grained. We also see that within this section the UCS and resistivity logs peaked with increased frequency indicative of both the hardness and heterogeneity of the formation. From this result we infer that these formations initiated the bit failure as ROP continued to dip even though consistent weight on bit was applied. The interval just below this section was not as damaging to bit since it was a more uniformed shale layer and an even UCS trend, however From 13,500 ft, a significant drop in ROP was observed and slight improvement from 13,570 ft to breakthrough at 13,665 ft. The rate slowed down significantly again at 14,050 ft and drilled to 14,268 ft at very low ROP and did not improve after altering drilling parameters as seen in Fig 3b. BHA was pulled to surface to inspect and change reamer and bit. The bit and reamer cutters were completely worn out. Bit dull grading was 7-3-CR-N-X-1/16-CT-PR and the reamer had no usable cutting structure left. It is believed

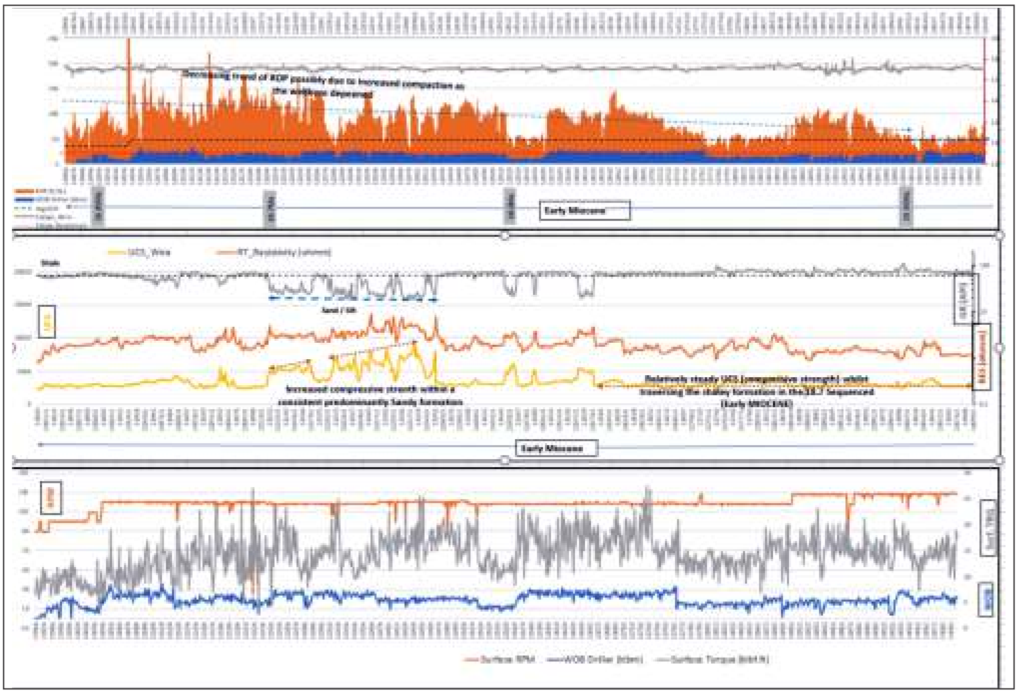

Figure 3a: Parameter Trend Analysis for Bit Run #1 (11,966-13100)-This plot shows the relationship between drilling parameters and the rate of penetration while also incorporating Geologic information and mechanical properties deduced from well logs.

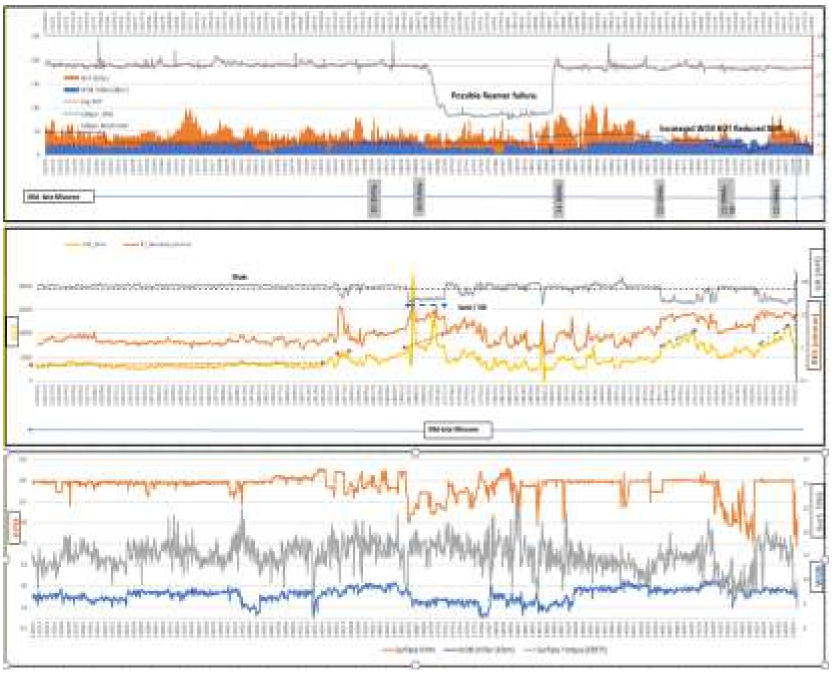

Figure 3b: Parameter Trend Analysis for Bit Run #1 (13,101-14,260)-This plot shows the relationship between drilling parameters and the rate of penetration while also incorporating Geologic information and mechanical properties deduced from well logs.

that the final damage to the bit and reamer occurred while drilling the hard and heterogeneous early Miocene formation from about 13,500ft where we see UCS log signatures and cuttings descriptions characteristics of hard and heterogeneous formations.
The last 4 tracks on Figure 4 show how the formation contribute to drilling difficulty such as damage to bits and reamers, downhole tools, directional performance, low ROP footage, multiple bit runs and borehole quality.

Between the intervals of 11,960ft- 12,500ft we observe an increase in the calculated UCS, Abrassion index, interfacial severity(rattines) and reduced porosity which all suggest that this section of the hole is difficult to drill than those below it. It is believed that this section initiated the bit and reamer damage. We see the same trend from about 13,500ft to the total depth of this section with increasing hardness of the formation with depth and age.

This analysis provides guidance for bit cutter type and bailing tendencies that serve as inputs for number of blades that a bit will require to drill through section in one run.

Run #2: 14,268' – 14,675'MD- 407' total footage

The 14 ¾” PDC bit was changed out to a model from the vendor that supplied the reamer. Reamer used for this run was identical to the one used on Run #1 and other components of the BHA remained the same.
New hole was made from 14,268 ft to 14,675 ft with very low ROP and another bit trip was called. Bit dull grading was 1-3-CT-S-X-1-WT-PR and the reamer was severely worn with similar dull characteristics of the previous run.
Parameter trend analysis for run 2 (Figure 5) was very poor as there was no improvement in ROP even though the bit was a new one. It was six bladed bit that possibly was not meant for this kind of hard and heterogeneous formation, however it was the only different spec available asides the seven bladed one that was used in the previous run.

The formation characteristics did not differ much from the previous run however we observe the shales transited from moderately hard to very hard in the early Miocene late Oligocene transition.

The drillability analysis (Figure 6) just like the previous run show an increase in the calculated UCS, Abrassion index, interfacial severity(rattines) and reduced porosity which all suggest that this section of the hole is difficult to drill. The base of the section showed marked increase in bailing index and apparently must have done much damage to the bit. This information when used with other bit selection criteria will definitely aid in better bit selection

Run #3: 14,675' – 15,319'MD- 644' total footage

This run used a new set of the primary bit and reamer.
The hole section was drilled from 14,675 ft to 15,319 ft with low ROP before decision was made to trip for bit.

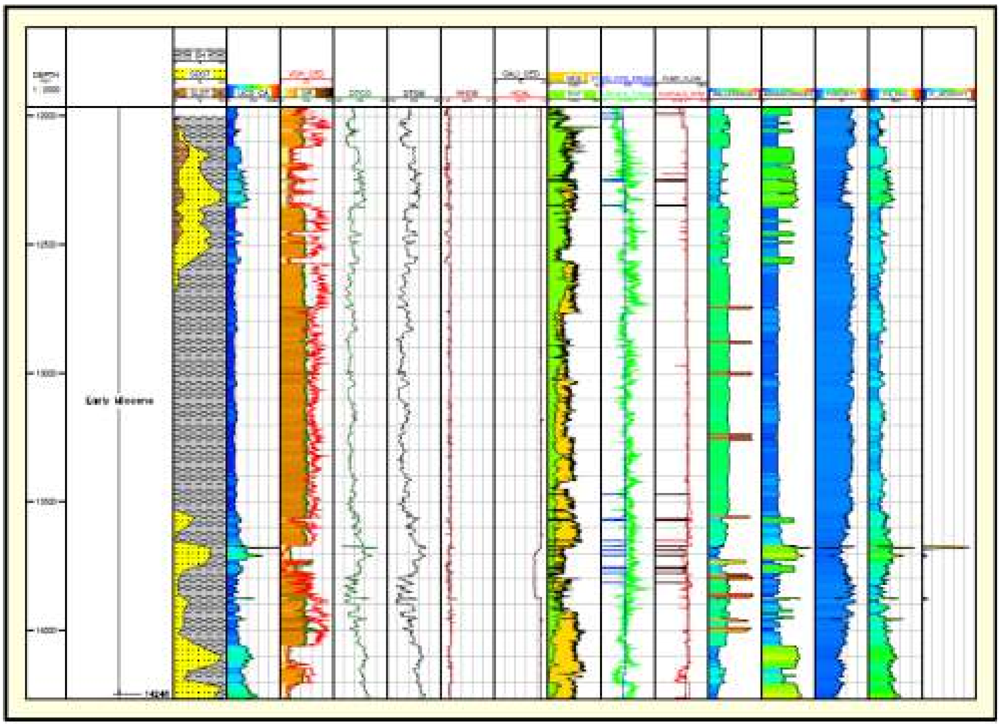

Figure 4: Results Of Formation Drillability Analysis for Run 1 (14,268' – 14,675').

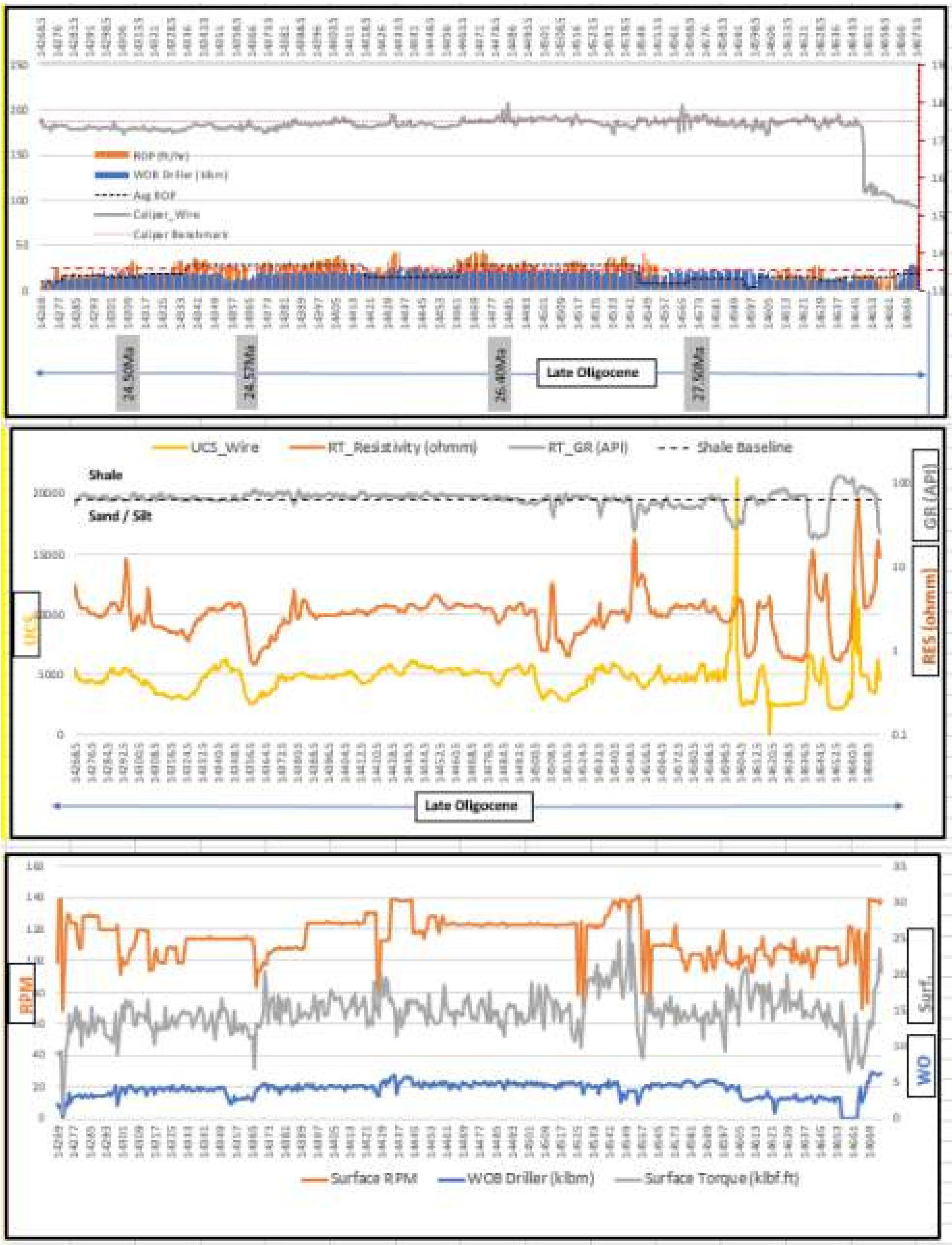

Figure 5: Parameter Trend Analysis for Bit Run #2 (14,268'-14,675)-This plot shows the relationship between drilling parameters and the rate of penetration while also incorporating Geologic information and mechanical properties deduced from well logs.

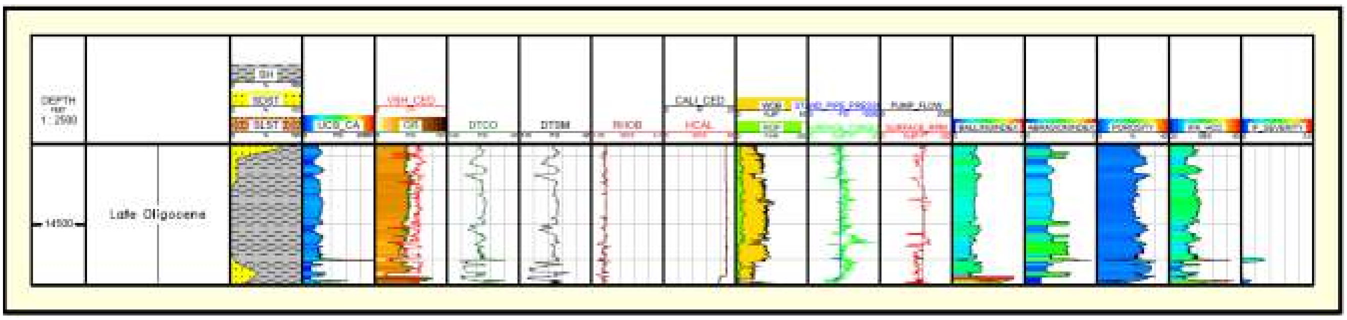

Figure 6: Results Of Formation Drillability Analysis for Run 2 (14,268'-14,675).

From 14,827 ft to 14,968 ft, a significant improvement in ROP was observed (Figure 7) with a steady torque and vibration was extremely low-Most part of the section was undergauged due to reamer failure and erratic UCS and RPM was observed within this interval. Bit dull grading was 1-8-RO-S-X-1-LT-PR and the reamer was severely worn with similar dull characteristics of the previous runs.

The formation characteristics and that of the result of the drillability analysis (Figure 8) compares favorably with that of previous run. However, the bit used in this run was same with that used in the first run and is most likely the reason for a better performance than previous run since this bit has 7 blades as against the 6 blades of previous

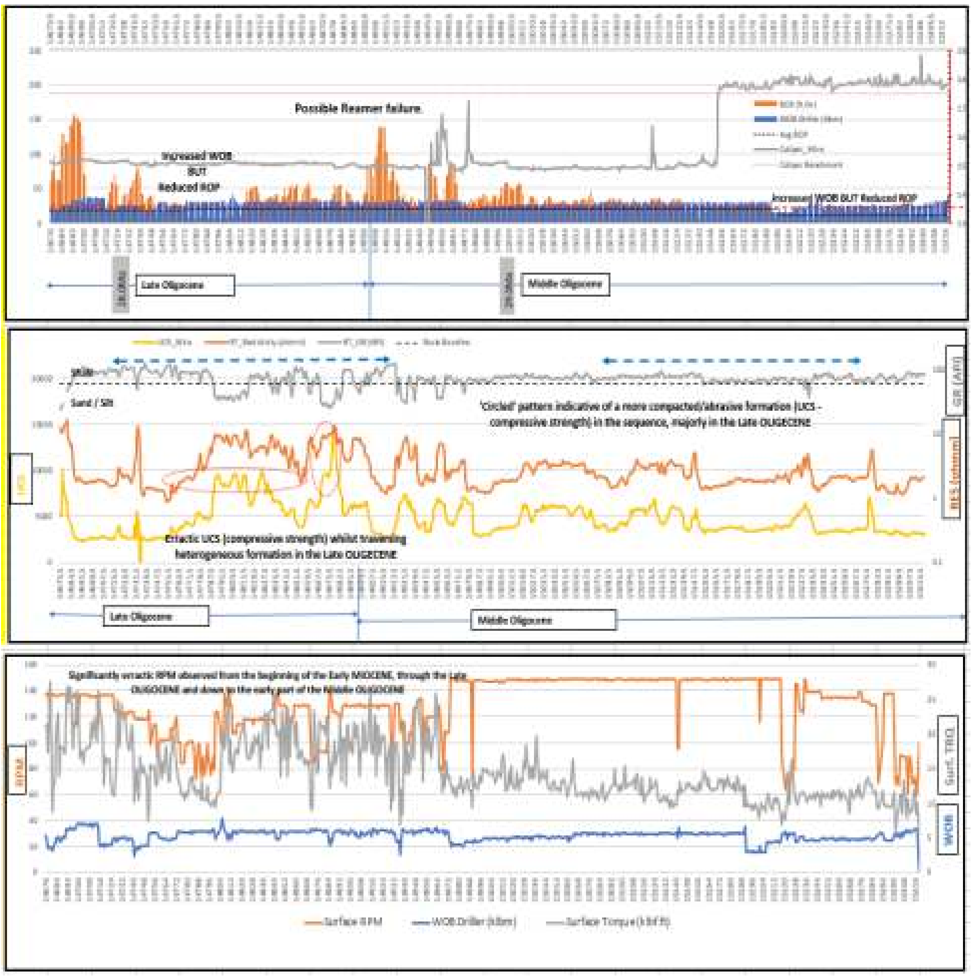

Figure 7: Parameter Trend Analysis for Bit Run #3 (14,675'-15,319)-This plot shows the relationship between drilling parameters and the rate of penetration while also incorporating Geologic information and mechanical properties deduced from well logs.

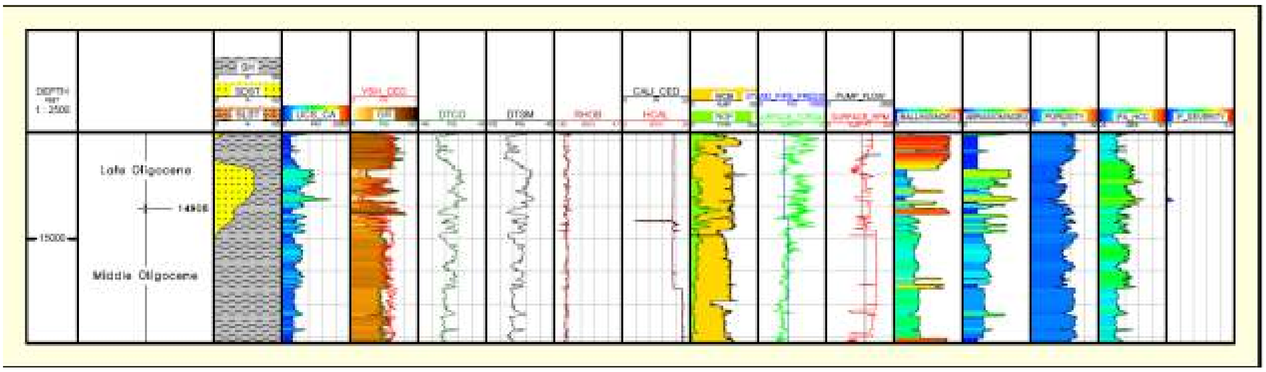

Figure 8: Results of Formation Drillability Analysis for Run 3 (14,675'-15,319').

runs.

Run #4: 15,319' – 15,685'MD- 366' total footage

This run used a new set of the primary bit and reamer. The BHA was configured to give a shorter bit-reamer offset to minimize vibration as experienced from the previous runs. Drilling from 15,312 ft showed similar stick slip vibration as in previous runs.

The hole section was drilled from 15,319 ft to section TD at 15,685 ft with low ROP. From 15,440 ft to 15,490 ft, a very low ROP was observed-the reamer performed better than the previous run as reamer failure was observed from 15,460 to 15,555 (Figure 9). Bit dull grading was 1-3-CT-S-X-1-WT-TD and the reamer was severely worn with similar dull characteristics of the previous runs.

The formation characteristics and that of the result of the drillability analysis (Figure 10) compares favorably with

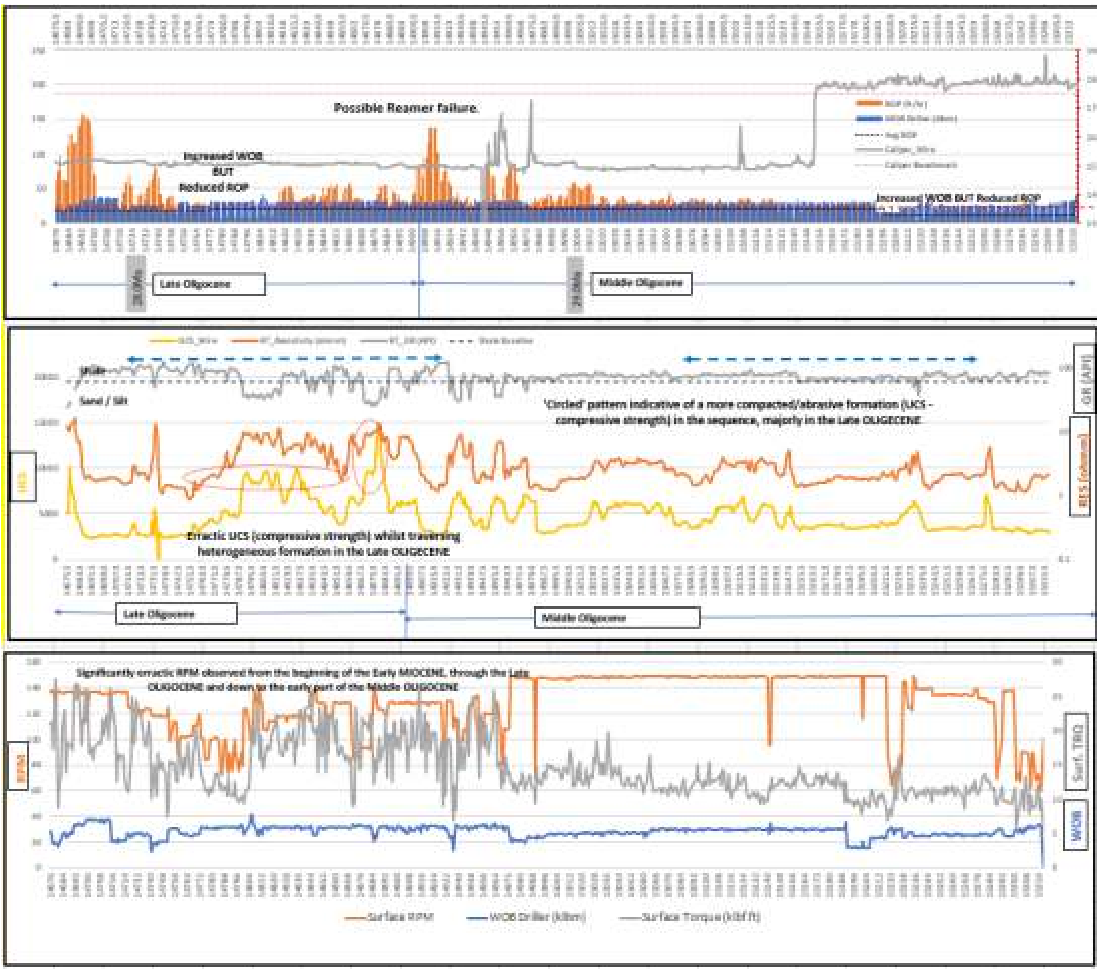

Figure 9: **P**arameter Trend Analysis for Bit Run #4 (15,319'-15,685')-This plot shows the relationship between drilling parameters and the rate of penetration while also incorporating Geologic information and mechanical properties deduced from well logs.

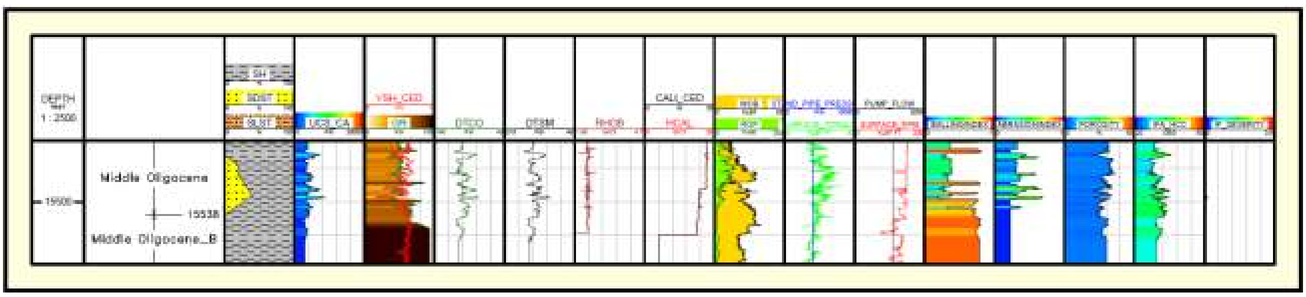

Figure 10: Results of Formation Drillability Analysis for Run 4 (15,319'-15,685').

that of the previous run. Since the same bit as run 3 was used in this section, reducing the bit reamer offset seem to have improved performance.

DISCUSSIONS

Wilmoth et. al (2004) proposed that formation induced damage was heavily influenced by formation heterogeneity and peak counts. This is a major cause of axial and or stick slip events and this in turn leads to PDC cutter breakage which compromises bit durability and or ROP. In order to mitigate this negative effect, operational limits of WOB, RPM and flowrates that will not excite vibrations are set by conducting a drill-off test.
Increased RPM and reduced WOB have been used in certain heterogenous formations and improved performances were observed. If this measure does not improve performance, it means a change of bit may be required. Bit designs with higher number of blades and cutter sizes than the previous run will likely improve performance once appropriate operational drilling practices are adhered to. However, changing of the bit cannot be effective until a good understanding of the drilling mechanics that can fail the rock, evacuate it efficiently when it is exposed to loads (WOB) and displacements (RPM) without exciting vibrations is understood.

Hardness alone should not be used as the only criteria in bit selection neither should the performance of the bit without due consideration for the formation as this could be misleading. A good understanding of the rock

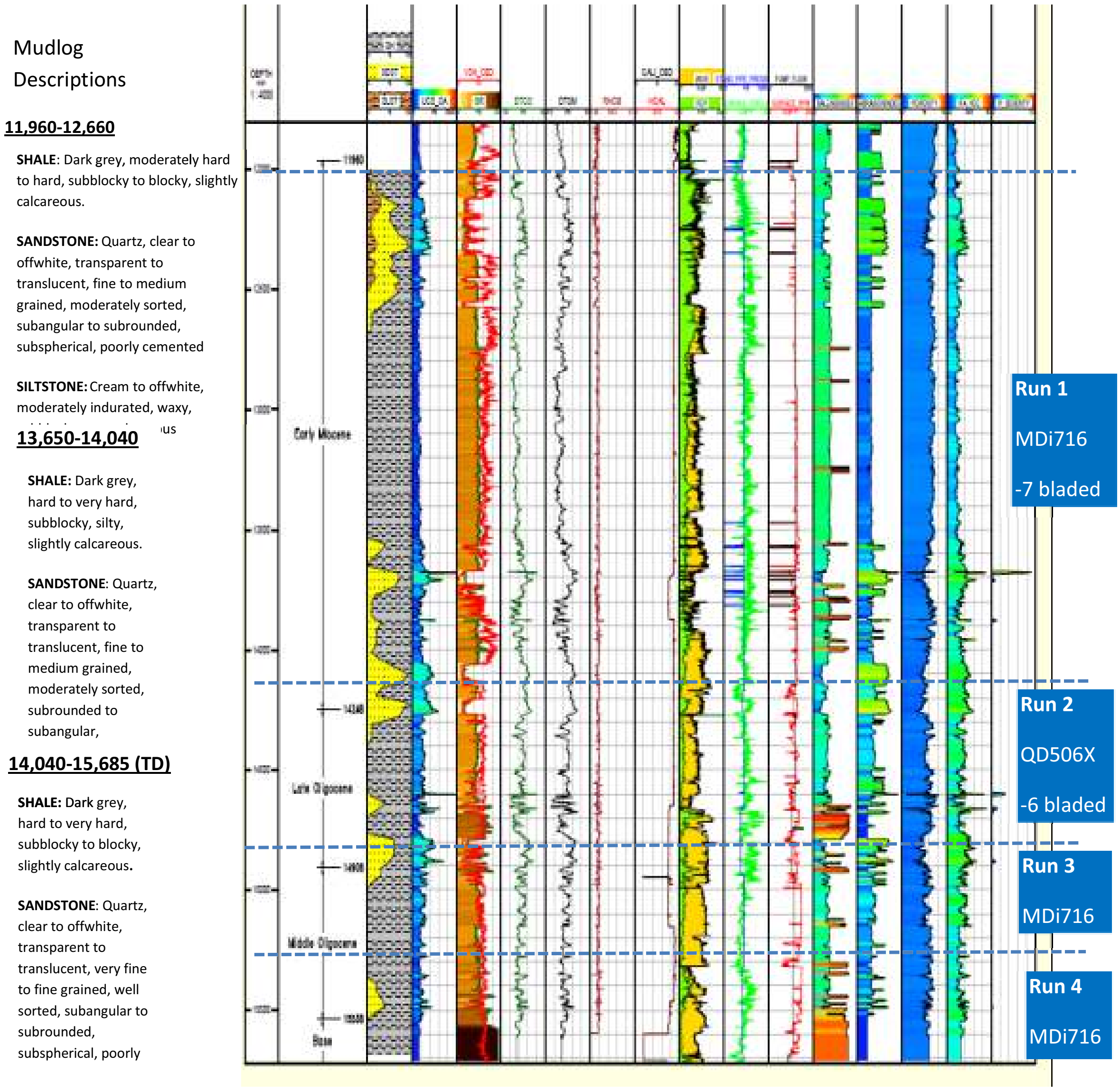

Figure 11: Composite plot of Formation Drillability Analysis Of Entire Hole section Showing The Different runs and formation characteristics.

mechanics is critical to understanding the drilling mechanics to be used in executing the well, and this should be considered as a first step in any bit selection process.
There seem to be some form of positive correlation between the resistivity and UCS logs, more studies would be carried out on this
The analysis done on this section as shown in Fig 11 show clearly the Age of the rock, Geological and Mechanical properties, alongside formation drillability analysis to aid bit selection for future wells within the study area.

CONCLUSION

Data analysis of the well reveal clearly that the analyzed well section is a difficult to drill formation. This was mostly influenced by the formation characteristics as shown by the formation drillability analysis. Hard and heterogenous formation deposited in weakly confined channels within the early Miocene and late Oligocene sand, shale and silt sequences show pronounced difficulty in drilling.

In order to mitigate the negative effect of hard and heterogenous formation for future wells within the study area, particular attention should be given to getting fit for purpose bit and reamer selection while incorporating other lessons learnt from this study.

RECOMMENDATIONS

Our well plans should have a robust formation drillability mechanical earth model alongside a PP/FG model especially for wells located in geologic environments that favour the deposition of hard and heterogeneous formation.

Bit and reamer selection would be key to overall operational efficiency. Cutter technology must be closely considered to ensure transitioning into another formation. The bit and reamer cutting structure must be stable and balanced to ensure appropriate weight distribution between the bit and the reamer. Bit-reamer synchronization should be modelled for selection. Selection should take into account bit aggressiveness relative to the reamer. Significant shock, vibration, and stick slip can occur if the bit drills faster than the reamer. A bit design to consider include long gauge bits with parabolic bit profile and depth of cut control.
The drilling of heterogenous layers and transition zones usually pose vibration challenges especially when the weight distribution between the bit and the reamer are not in sync
The design of the system BHA should consider reamer placement for stabilization while satisfying other requirements. On-Command Digital Reamers technology can be considered and placed near the bit to improve stability and ability to drill ream while drilling hard and abrasive formations.
Another key area in drilling and undreaming difficult formations is the parameter management. A good practice is to have a real-time drilling dynamics and optimization tools integrated into the BHA to provide an insight of downhole data while drilling and gives an onsite active intervention capacity, The downhole data collected real-time can be fed into an analytical tool for processing and easy trend monitoring which can ultimately aid decision making about drilling performance

NOMENCLATURE

ROP	- Rate of Penetration
BHA	- Bottom Hole Assembly
RPM	- Revolution Per Minute
WOB	- Weight on Bit
PDC	- Poly Diamond Crystalline
MD	- Measured Depth
UCS	- Unconfined Compressive Strength
LWD	- Logging While Drilling
MWD	- Measurement While Drilling
TD	- Total Depth
RSS	- Rotary Steerable System

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