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Successful Utilization of the Shaped Point Loading Edge Cutters Technology to Eliminate Directional Downhole Tools Failures and Enhance the Drilling Performance of Long Laterals in the Middle East

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ABSTRACT

One of the main objectives in directional drilling operations is finding ways to optimize the drilling performance. Drilling and geo-steering through dense Carbonates and Anhydrite layers introduces various challenges such as poor rate of penetration, high near-bit vibrations and down hole tool failures. To overcome these challenges, a shaped edge polycrystalline diamond compact (PDC) cutter technology was introduced for the first time in an integrated oil production turnkey project in the Middle East. The shaped edge PDC cutter technology employs a point loading chamfer on the diamond tip of the PDC cutter for efficient load distribution on the cutter edge and more weight transfer to smaller portions of the drilled rock. The state-of-the-art cutter technology is developed to increase the bit stability and rock destruction efficiency while drilling through highly interbedded and hard formations. In addition to the new PDC bit design and the in-depth offset wells analysis and formation specific parameters roadmap, an optimization process comprising motorized rotary steerable system (MRSS) bottom-hole assembly (BHA), enhanced trajectory design, drilling fluids and system hydraulics design and subsurface geomechanics modelling were introduced to optimize the drilling performance and drill the lateral section in one run.

The proposed shaped edge PDC bit design in addition to the optimization roadmap delivered two consecutive laterals with an exceptional performance without downhole tool failures. Each lateral is almost 4,500 ft long, drilled through interbedded carbonate formation capped with dense Anhydrite layer. The average rate of penetration (ROP) improved by 70% compared to the first lateral drilled in the same well which consumed two bits/trips due to downhole tool failure. With respect to drilling the Anhydrite cap rock interval, the new PDC bit design succeeded to double the ROP and reduce the near-bit lateral vibrations by 125% while eliminating the surface stick-slip vibrations.

EXTENDED ABSTRACT

Application Background

The oilfield of the study area is a major oilfield under development in the Middle East. The field development plan comprises drilling producer single lateral and multi-lateral wells, in addition to water injection wells, in the Arabs reservoir. The reservoir is a fine-grained reservoir, consisting of porous layers of soft carbonates (Limestone and/or Dolomite) separated by anhydrite layers and has medium to high porosity. The average formation rock strength is between 5 – 10 kpsi. The drilling operation comprises motorized rotary steerable system drilling of 6-1/8" hole and geosteering across the reservoir to well total depth with an average lateral length of 3,000 - 5,000 ft long. Table 1 illustrates the reservoir lithology description.

Table 1: Lithology description of the application

Formation	Member	Description
ARAB	ARAB-A, B & C	It is composed mainly of Carbonates (Limestone and/or Dolomite) & Anhydrite. It is picked by appearance of carbonates (Limestone and/or Dolomite) with fast ROP.
	ARAB-D	It is composed mainly of Carbonates (Limestone and/or Dolomite). It is picked by appearance of carbonates (Limestone and/or Dolomite) with fast ROP.
Note : ROP slows down in Anhydrite and speeds up in the carbonates (Limestone & Dolomite), Halite (Salt) stringers occur in the Arab formation, it can be identified by distinctive fast ROP breaks and an increase of salinity (chloride) in the drilling mud.		

Application Challenges

The main challenges identified while drilling the 6-1/8in lateral section are:

Drilling Vibrations. Every drilling process involves drilling vibrations, which are inevitable. High vibration levels can be harmful to the integrity of drillstring components and drilling performance. The cyclical variation of drill string torque levels results in torsional vibrations and twisting motions. This vibrational mode is frequently referred to as stick-slip (Halsey et al., 1986). Figure 1 illustrates the stick-slip vibration mode. The bit briefly stops rotating at regular intervals until the string torques up, after which it spins freely at a high rev/min. Until the applied parameters are altered or the drillstring is removed from the bottom to reset the drilling parameters, this cycle of stick and slip continues. Three to fifteen times the applied surface rev/min can differentiate the instantaneous rev/min. Drill string fatigue, bit cutter damage, BHA failure, stabilizer wear, and over-torqued connections can all result from severe stick-slip (Al Ghamdi et al. 2017). The manufacturer's permitted vibrational limits for the RSS and LWD tools must be taken into account. The risk of failure increases if the tools are used outside of these parameters for a certain time interval. The lateral section of the subject application suffers from lateral and stick slip vibrations induced by the interbedded layers and the hard Anhydrite stringers.

Directional Control. The need for additional directional work increases application challenges due to the objective of precise borehole placement at the reservoir top layer. Drilling the hard anhydrite stringers presented significant bottom hole assembly control challenges and lowered ROP. A matched bit design is crucial for horizontal steering utilizing RSS in order to improve directional control and achieve accurate borehole placement.

Non-Productive Time (NPT). The overall rate of penetration of the lateral sections and, subsequently, the intended well delivery, are heavily impacted by severe drilling vibrations in addition to tool failures. Drilling parameters are frequently modified to overcome these vibrations. The investigation of the offset wells revealed tool failures and PDC bits damage.

Loss of Circulation. While drilling the long lateral sections, partial or complete loss of circulation is encountered due to the fractured reservoir environment. Before drilling, a thorough analysis of the offset wells and their directions is carried out to assess the possibility of circulation loss.

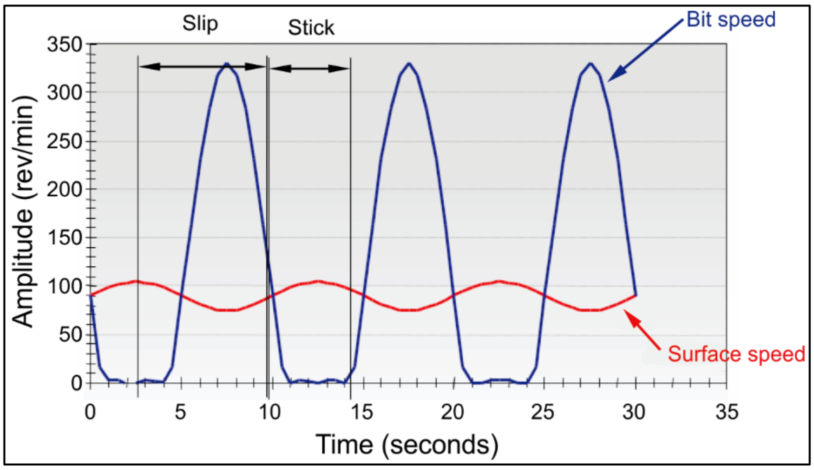


Figure 1 Stick Slip vibration mode

Offsets Analysis

Historically, dual chamfer cutters on PDC bits with motorized rotary steerable system were utilized to drill and geo-steer the lateral section with the idea of providing a durable edge to drill through the capped anhydrite layers without severe cutter damage which may lead to the loss of the cutting structure efficiency and accordingly the failure to drill the entire section in one run. However, the presence of drilling vibrations, predominantly on the RSS steering unit, presented the main challenge in the offset wells as the utilized bit designs with the current technologies lead to controlling the drilling parameters to maintain drilling within the RSS manufacturer vibration limits. This lead to poor performance and in some instance downhole tools failures resulting in undesired trips to change the tools with more than 24 hours nonproductive time in each lateral.

The offsets analysis focused on a recent well that faced such challenge where a six bladed, 13 mm dual chamfer cutter PDC bit with back-up cutters design was used to drill the section. Nevertheless, the bit drilled 1,097 ft of the entire 4,804 ft section with high steering unit lateral vibrations (+10 gn) and (+5 gn) MWD stick-slip levels as shown in Figure 2. Several attempts were made to drill the dense anhydrite layers with major control in parameters to mitigate such out of specifications vibrations with no improvement leading to down tool failure and pulling out of hole with an unplanned trip to change the tools. The bit was found in good condition with dull of 1-1-WT-A-X-I-NO-DTF as shown in Figure 3, but the decision was made to change the bit with a planner PDC cutting structure option. The planner PDC cutters bit exhibited high vibration levels similar to the dual chamfer bit design in the anhydrite layers till the landing section inside the reservoir. The planner cutters bit managed to drill the remaining of the lateral section to TD as shown in Table 2 and Figure 4.

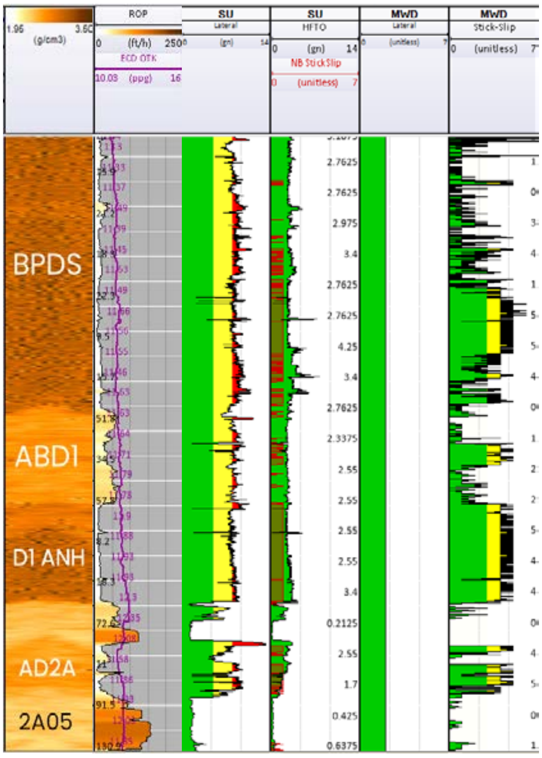


Figure 2: SU Lateral & SS vibrations of the offset well drilling across the anhydrite layers

Figure 3: Face view dull picture of the 6 bladed, 13 mm dual chamfer cutter with backup PDC cutters design

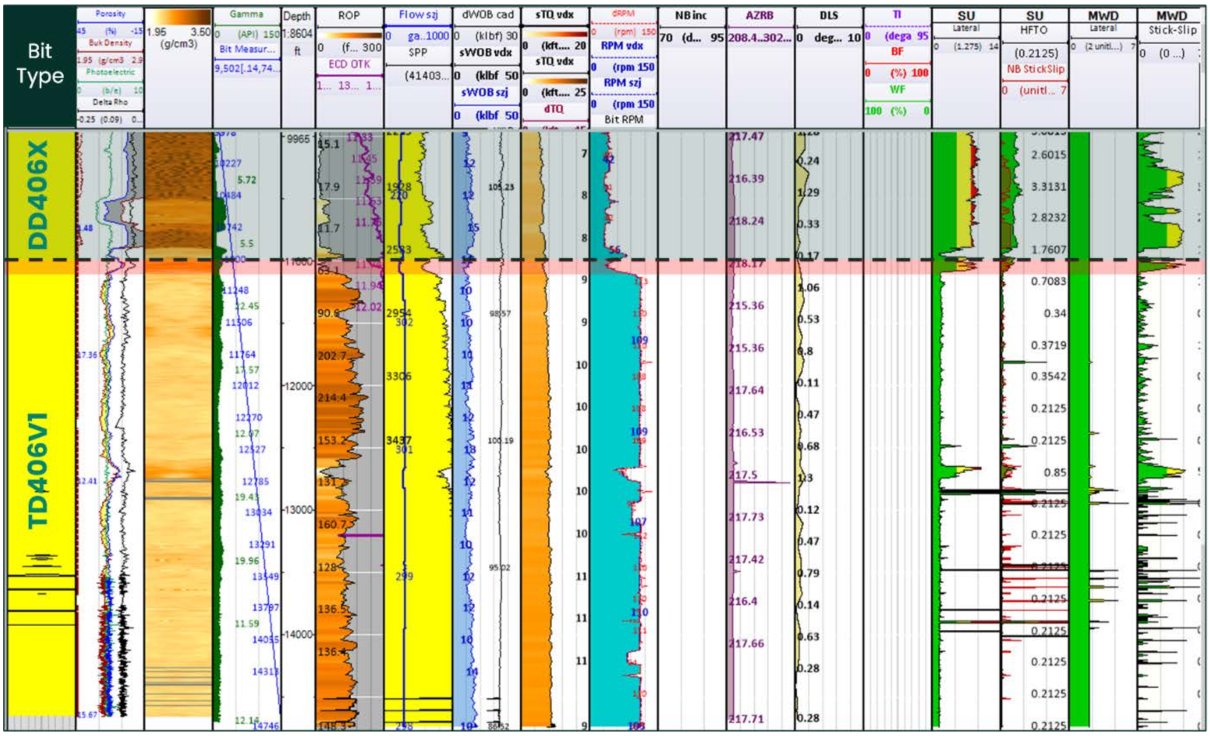


Figure 4: ROP, Density, Vibrations of the entire offset well including two runs

Table 2: Offset Well Bit records and Overall Performance

Date	BHA	Rig	Well	IADC	Class	Bit Size	Bit Type	Depth in	Depth out	Footage	Hours	ROP	Dull
2/24/2022	MRSS	Rig #1	Offset Well	M233	PDC	6.125	DD406X	9942	11039	1097	70	15.67	1-1-WT-A-X-I-NO-DTF
2/27/2022	MRSS	Rig #1	Offset Well	M233	PDC	6.125	TD406V1	11039	14746	3707	53.75	68.97	1-1-WT-A-X-I-NO-TD

The offset well drilled the section using two different PDC cutting structures and the bits came out in good condition; however, the main drawback was experiencing high level of stick slip and steering unit laterals with reduced penetration rate along with downhole tool failure. It was required to come up with a new solution to overcome these challenges without sacrificing the run performance.

Hence, the approach was to focus on improving the cutting action within the anhydrite layers whilst mitigating the drilling vibrations thus preserving the downhole tools operational lifespan, improving the bit durability, and reducing the drilling costs.

Technical Solution

PDC drill bits performance has increased steadily since their introduction in the 1970s thanks to advancements in PDC technology, cutting structure, dynamic stability, hydraulics, and steerability (Gerbaud, Menand and Sellami 2006). Table 3 provides a summary of the directional company PDC bit requirements to guide in the new PDC bit solution (AlGaiar et al. 2022).

Table 3: PDC bit requirements for RSS applications

Attributes	Affects	Concerns	
Profile Length	Bit walk Drilling vibrations	Toolface control an issue	- Short profile required (1 - 3)
Bit Length / Make up length	BUR capability	Higher Steer force required to achieve BUR	- Directional tool / BHA reliability is a concern - Short shank required
Axial Aggressiveness	Higher exposure leads to torsional vibrations	Toolface control an issue	- Premature bit damage - Directional tool / BHA reliability is a concern
Lateral Aggressiveness	Leads to Lateral vibrations	Affects side cutting ability, hole quality and lateral vibrations	- Premature bit damage - Directional tool / BHA reliability is a concern
Impact arrestors	Bit walk Drilling vibrations	To limit cutter gouge and stickslip	- Need to be tailored to the application
Gauge protection	Gage integrity is a concern in directional holes	Affects the borehole quality and integrity	- Premature bit damage - Under gauge bore hole
Gauge configuration	BUR capability	Higher steer force required to achieve BUR	- Directional tool reliability is a concern
WOB and GPM Limits	Limits performance	Should match the high ROP application	- Low ROP - Less HSI

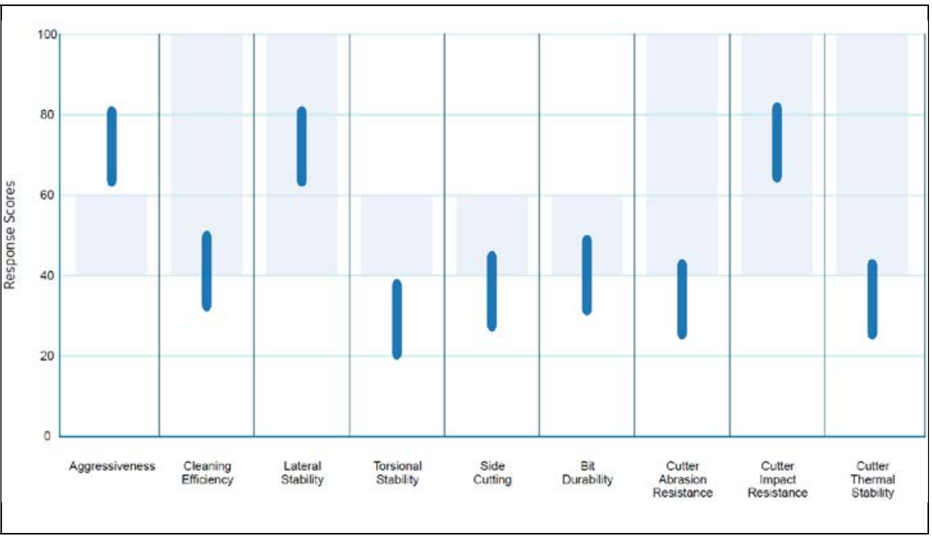
Drilling through heterogeneous formations especially though interbedded anhydrite layers cause an increase in vibration and that will lead to drop in the performance along with tool damage. Directional application required efficiency with fast drilling while maintaining tool face control. Previously, the main rely was on the conventional PDC with dual chamfer cutting edges. Where dual chamfer is working to increase the torsional stability and durability of the cutting edge by reducing the aggressiveness levels through interbedded formations to survive through impact prone application. Yet, that reduced the efficiency of the cutting structure and presented high steering unit lateral vibration due to the shearing action of the cutting structure which increase the area of friction especially while drilling through ductile rock or hard to indent rock.

The point loading cutters methodology was introduced and was strategically placed on the bit profile in the cone area providing a traditional point loading approach by distributing more weight to a smaller portion of the rock. This allows the cutter to penetrate ductile formations and generate maximum rate of penetration by reducing the weight on bit requirement compared to dual chamfer cutters; in addition, the point loading cutters reduce the friction generated through the edge of the cutters in the cone area leading to more stable response through the hard to indent rock. Figure 5 shows an example of the shaped cutters technology design and Table 4 represents the customized PDC bit design specifications and features.

Figure 5: Example of the shaped cutters technology design

Table 4: 6-1/8in DD406VT PDC Bit Specifications

IADC Code	M233	
Body Type	Matrix	
Total Cutter Count	33	
Primary Cutter Size	13 mm	
Nozzles Quantity	3	
Junk Slot Area	5.708 in^2	
API Connection	3-1/2 REG. PIN	
Make-up Torque	12.4 – 13.6 ft.klbs	
Make-up Length	7.660 in	
Gauge Length	2in Step (1in @ 0.050” & 1in @ 0.100”)	
Max. WOB	24.0 klbs	
Special Features	D (Directional Option), SHP (SHP - Optimus™ Prism and/or Apex shaped cutter technology), SS (Short Shank), G3 (Step Gauge), G7 (TSP Gauge), STE (StayTrue Element), PR6 (EB short profile), U4 (Updrill)	

Bit Response Chart	

Field Deployment

Recognizing the challenges faced while drilling the heterogenous formation with capped anhydrite layers in the offset well that let to unplanned trip due to the down tool failure, the new PDC bit design six bladed, 13 mm cutter with point loading cutters in the cone area and 2 in stepped gauge was utilized with motorized rotary steerable system in the same well on the second lateral.

The bit managed to drill the entire section of 4,574 ft to section TD in one run while achieving triple the ROP through the anhydrite layers and 70% ROP improvement compared to the two combined runs of the first lateral. Stick-slip vibrations was reduced dramatically, and the steering unit lateral vibrations went down by 50% saving the directional tools from failures. The bit came out in a rerunnable condition with dull grading 1-1-WT-A-X-I-NO-TD and it was rerun in the third lateral and achieved a consistent performance result with at least double the ROP through the anhydrite layers. Table 5 illustrates the runs summary. Figure 6 and 7 represents the recorded vibrations and the bit dull after pulling out of hole to surface respectively.

Table 5: Point Loading PDC design performance comparison

Date	BHA	Rig	Well	IADC	Class	Bit Size	Bit Type	Bit SN	Depth in	Depth out	Footage	Hours	ROP	Dull
2/24/2022	MRSS	Rig #1	Offset Lateral #1	M233	PDC	6.125	DD406X	7915130	9942	11039	1097	70	15.67	1-1-WT-A-X-I-NO-DTF
2/27/2022	MRSS	Rig #1	Offset Lateral #1	M233	PDC	6.125	TD406V1	7913703	11039	14746	3707	53.75	68.97	1-1-WT-A-X-I-NO-TD
Offset Lateral #1 Overall Performance											4804	123.8	38.82	
3/6/2022	MRSS	Rig #1	Lateral #2	M233	PDC	6.125	DD406VT	7914726	9009	13583	4574	69.5	65.81	1-1-WT-A-X-I-NO-TD
Lateral #2 ROP Improvement													**70%**	
3/13/2022	MRSS	Rig #1	Lateral #3	M233	PDC	6.125	DD406VT	7914726	8172	12233	4061	61.75	65.77	1-1-WT-N-X-I-NO-TD
Lateral #3 ROP Improvement													**69%**	

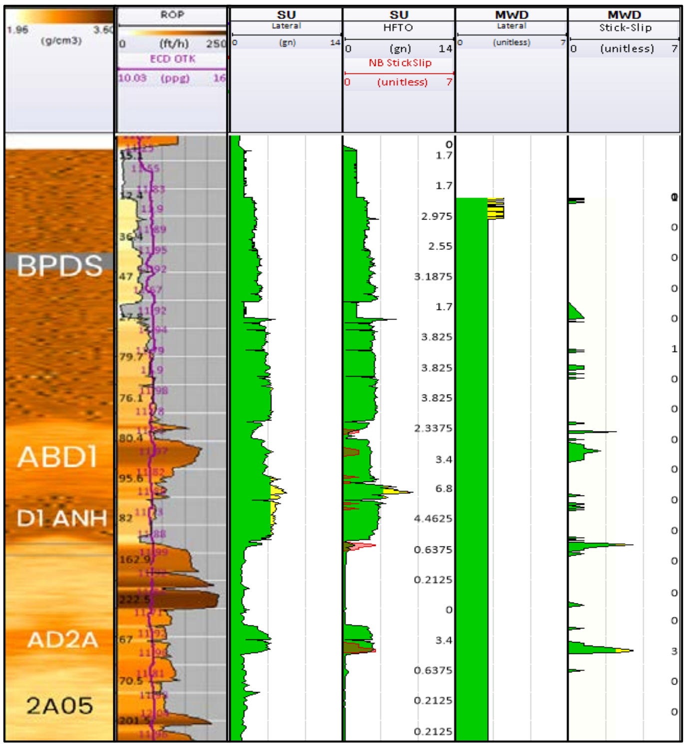


Figure 6: Improved lateral and SS vibrations compared to the offset lateral drilling across the anhydrite layers

Figure 7: DD406VT showed the required durability and ability to drill multiple sections

Conclusions

The implementation of the optimization methodologies helped achieving new performance records in the most challenging drilling environments. The new bit design established greater ROP response over the conventional cylindrical edge PDC cutters while improving the overall stability and steerability of the drilling system. The evolvement of the cutter edge showed substantial outcomes in terms of penetration rates, bit stability, and total cost savings by overcoming the drilling challenges and reducing the number of trips required to drill to well TD, thus reducing the overall well delivery time.

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