Turbine technology innovations may enhance operator ability to tap reservoirs below 15,000 ft

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AS THE DEMAND for hydrocarbons in the United States continues to increase, reservoirs at depths of 15,000 ft or less are becoming increasingly depleted. Historically, 93% of all US production comes from formations above 15,000 ft, and current drilling trends document a negligible effort to discover or develop reservoirs at 15,000 ft or below.

For example, over the last 10 years, more than 35,000 wells have been drilled on the outer continental shelf (OCS). Of these, only 1,842 wells penetrated strata below 15,000 ft. Statistics for land drilling are even more indicative of this trend, with only 2% of all US wells going below 15,000 ft over the last decade. Additionally, since 1997, only 25% of the wells drilled below 15,000 ft went beyond 18,000 ft.

With production declining and fewer shallow reservoirs being discovered, necessity demands the industry increase its focus on evaluating the economics of discovering and developing deep reserves. Historical limitations include expensive, high-capacity rigs and operations with extreme spread rates. It's estimated that with current technology, only 5%-12% of known deep reserves can be produced economically.

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The most pressing obstacle is increasing penetration rates (ROP) at depths below 15,000 ft, where formations are typically hard and/or abrasive and elevated thermal gradients that create an extremely harsh condition. Of particular concern at these depths is overall drilling efficiency measured by ft/day drilled. Thus, increasing the percentage of on-bottom drilling time with improved tool efficiency and reduced number of trips through increased tool reliability/durability is critical.

The ultimate solution will materialize when these improvement initiatives are combined to increase the economic feasibility of drilling through the deeply buried reservoir with the minimum number of trips at the highest possible ROP.

INTRODUCTION

From a drilling perspective, several new technologies are being used in challenging HPHT environments. However, few directly address the downhole drive system. To fill this void, the service provider is currently conducting research and development efforts in turbine technology to increase ROP and run lengths below 15,000 ft. To accomplish this, it’s imperative the entire bottomhole assembly (BHA) be analyzed in both static and dynamic modes to optimize the entire drilling system.

Engineers defined a focus area for the optimization effort that included reservoirs typically below 15,000 ft in hole sections that required multiple trips to change out bits. They studied how different mud systems and mud densities affected downhole tool performance in formations with compressive strengths of approximately 15,000 psi and temperatures >300°F.

The economic objective would be to increase gross footage/day while improving penetration rates in the slower, more difficult sections of the well. Improving ROP would also help improve borehole quality by reducing time in section and reducing the need for excess cement volumes when casing. Another prime objective is to reduce the number of trips and minimize non-drilling “flat” time.

Additionally, engineers want to reduce drill string problems and the levels of damaging drilling dynamics while increasing borehole quality to obtain more reliable open-hole logs, and ensure that tubulars reach bottom without issues on the first attempt.

CHALLENGES

In the slower, more difficult intervals of the well, issues include overpressured zones, high bottomhole pressures (plastic shale), hard and/or abrasive sandstone, chert, loss zones, drillstring integrity, borehole tortuosity, surface equipment reliability and casing wear. These potential issues are considered during pre-planning in order to raise awareness for the operator and service provider to take a holistic, systems approach to performance improvement.

To efficiently drill below 15,000 ft, operators must be willing to apply new and/or established technology under extreme (pressure and temperature) conditions and operating parameters. Service companies are working to advance and expand turbine technology into applications traditionally drilled with a positive displacement motor (PDM).

Figure 1: Turbine component parts with stator/rotor blades and PDC bearing sections (near bit).
It’s well known that turbodrills generate more downhole power than PDMs under equal hydraulic conditions due to the efficiency of their unique multi-staged vane drive system. This configuration allows mud to pass through each stage where the fluid is redirected from the stator to the rotor, resulting in rotational force that is transferred to the shaft and down to the bit (Figure 1).

Similar to a PDM, the turbodrill generates mechanical power through a pressure drop across the drive system coupled with the fluid flow rate. Generally, the greater the pressure drop capacity of the tool, the greater the potential for delivering mechanical power to the bit. Because the turbodrill’s power-generation system is entirely metallic, it’s capable of supporting an extremely high pressure drop that creates greater mechanical power compared with a mud motor. Stated in equation form:

\[ \text{HPh} = \frac{(\text{Pressure} \times \text{Flow})}{1714} \]

This high-power output, low depth of cut and low applied weight on bit allows the turbine to operate with lower fluctuating torque response and less reactive torque than a typical PDM, resulting in better tool-face control during directional work in these deep environments. Additionally, there is no performance degradation during orienting periods as the additional string RPM (40-120 RPM) is negligible relative to the speed (800-1,200 RPM) of the turbodrill while under load. Further the concentric nature of the turbodrill’s drive train and shaft rotation results in very low vibration levels.

**Borehole Quality**

The increased tool-face control minimizes the requirement for long periods of orienting, which limits dogleg severity, and when combined with a long gauge box connection bit, minimizes hole spiraling. This delivers a smooth concentric wellbore, allowing casing to be run to bottom without the problems often encountered when using a PDM. The increased borehole quality cuts cementing costs by reducing the total slurry volume required to properly seat the casing.

Additionally, the superior hole geometry results in less drill string wear, fewer wiper trips, improved hole cleaning, and often allows a smaller hole to be drilled for a given casing size. For example, in West Texas, utilizing a turbodrill allows the operator to reduce hole size to 8 ½ in. from the 8 ¾ in. required if PDM- or rotary-drilled.

**Tool Reliability**

To increase tool life, the turbodrill utilizes PDC thrust bearing to absorb axial loads while tungsten carbide hard coatings are used in the radial bearings to absorb lateral loads. This combination provides superior performance and significantly increases operational durability relative to a PDM, especially in a high-temperature and oil-based drilling fluid environment. The all-metallic bearing pack, coupled to an all-metallic power section, provides superior reliability in high-temperature, high-pressure, high drilling/mud solids applications, especially compared with a PDM with its elastomer stator design.

**Case Study 1**

**West Texas**

Historically, the operator drilled the top 1,500 ft of formation in the 8 ¾-in. hole section with PDC bits. The first PDC would drill out the cement and casing shoe, then make approximately 900 ft of hole. The second PDC would be tripped in and drill the remaining 600 ft to

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**Table 1:**

<table>
<thead>
<tr>
<th>Offset #1</th>
<th>Quantity of Bits (all runs on motor)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
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</thead>
<tbody>
<tr>
<td>2 RCs</td>
<td>1,609</td>
<td>230.0</td>
<td>7.0</td>
<td>61.6</td>
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<thead>
<tr>
<th>Offset #2</th>
<th>Quantity of Bits (all runs on motor and rotary)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
</tr>
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<tbody>
<tr>
<td>1 PDC + 2 RCs</td>
<td>1,606</td>
<td>271.0</td>
<td>5.9</td>
<td>90.7</td>
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<tr>
<th>Offset #3</th>
<th>Quantity of Bits (all runs on motor)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
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</thead>
<tbody>
<tr>
<td>3 RCs</td>
<td>1,648</td>
<td>306.0</td>
<td>5.4</td>
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**Table 2:**

<table>
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<tr>
<th>Turbine Well #1</th>
<th>Quantity of Bits (all runs on turbine)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
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</thead>
<tbody>
<tr>
<td>1 PDC + 2 Impregs</td>
<td>2,033</td>
<td>318.5</td>
<td>6.38</td>
<td>101.1</td>
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<th>Quantity of Bits (run on turbine)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
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</thead>
<tbody>
<tr>
<td>1 PDC / Impreg</td>
<td>2,422</td>
<td>309</td>
<td>7.84</td>
<td>31.2</td>
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<th>Turbine Well #3</th>
<th>Quantity of Bits (runs on turbine)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
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<tbody>
<tr>
<td>1 Impreg</td>
<td>1,589</td>
<td>278</td>
<td>5.72</td>
<td>31.1</td>
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<th>Quantity of Bits (runs on turbine)</th>
<th>Feet Drilled</th>
<th>Drilling Hours</th>
<th>Average ROP</th>
<th>Trip Hours</th>
</tr>
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<tbody>
<tr>
<td>1 Impreg K705</td>
<td>1,507</td>
<td>210.5</td>
<td>7.2</td>
<td>30.5</td>
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</table>
approximately 14,000 ft. At that point, a heavier set PDC and roller cone bits make multiple runs to TD the hole section around 18,000 ft. Formations include Wolfcamp, Strawn, Atoka and Morrow.

**Challenges:** The main challenges include high temperatures (300° F) and heavy 16-ppg mud, in addition to lost-circulation zones. Operations were hampered by low ROP and short roller cone and PDC bit life, as well as vibration-induced downhole PDM tool failures. On offset wells, the operator was forced to alternate several roller cone and PDC bits to finish the hole section. All these factors drove up drilling costs, with each trip taking 30 hrs or longer to change out the damaged/worn tool.

**Proposed objectives:** To alleviate the escalating drilling/trip costs in the 8 ¾-in. section, the operator needed to increase on-bottom drilling time and improve ROP as much as possible. A plan was proposed to drill out the cement and casing shoe with a turbodrill/PDC BHA, then continue drilling the required 1,500-ft section. The remaining 4,000 ft would be drilled with another turbine and two diamond impregnated bits.

**Performance (turbine vs best offsets):** The first case study, Turbine Well #1, was less than ideal due to the learning curve. However, on Turbine Wells #2, #3 and #4, the driller and field engineers managed to optimized turbine performance with the bit and significantly reduced total trip hours while improving ROP (Figure 2).

On Turbine Well #2, turbodrill helped reduce trip time by 66% and increase ROP by 33%. The increased downhole power and less WOB also helped reduce total bit count from one PDC and two roller cones on Offset Well #2 to one PDC and one impregnated bit on Turbine Well #2.

![Figure 3: Open face impregnated design (K705) improves hydraulic flow and optimizes cleaning for increased ROP.](image-url)
On Turbine Well #3, turbodrill helped reduce trip time by 60% and increase ROP by 6%. The increased downhole power and less WOB reduced total bit consumption from three roller cones to one impregnated bit.

On Turbine Well #4, the trend continued in both the reduction in trip hrs/bit consumption and increased ROP. Turbine Well #4 was drilled with an industry-leading Kinetic diamond impregnated bit (Figure 3) with grit hot pressed inserts (GHI). GHI inserts consist of a proprietary combination of diamond crystals and tungsten carbide matrix that allows the bit to drill out float equipment without compromising the performance in the subsequent section.

**CASE STUDY 2**

**Tuscaloosa Trend, Louisiana**

The drilling environment in the Tuscaloosa Trend is extremely harsh. Wells are typically drilled with 15+ ppg oil-based mud, and bottomhole temperatures run in the 380° to 400° F range. Challenges in the False River Field included low ROP, short bit footage, downhole motor failures, high trip costs and HSE issues. The safety concerns included hole problems, stuck pipe and well control. Frequent drill string failures and excessive casing wear while rotary drilling were also driving up drilling costs.

**Benchmarks (False River Field):** Historically, the operator drilled the 8 ½-in. hole section with a positive displacement motor and a PDC bit. However, on the last run, the BHA was pulled for a downhole motor failure after drilling just 242 ft at 2.3 ft/hr for an average cost/ft of $1,753. The PDC was still in good shape and was dull-graded 1-1-WT.

**Proposed improvements:** The operator wanted to increase tool reliability below 19,000 ft MD and minimize tripping to help reduce casing wear and the risk of drill string failure. This would greatly improve project economics because it takes approximately 42 hrs/round trip from 22,000 ft MD in a tool-damaging hot hole environment. Engineers also wanted to improve ROP without limiting on-bottom drilling time tripping for new bits.

**Performance results:** The all-Smith BHA was run, drilling 980 ft of interbedded formation at 4 ft/hr, reducing cost/ft to $898, an improvement of 77% compared with the benchmark of $1,753/ft. There were no torque or casing wear/tool reliability problems. The BHA completed the hole section in one run with the bit pulled in like-new condition with a dull graded at 1-1-WT. The increased reliability and high RPM/torque turbine, combined with the optimized impregnated bit, improved ROP by 74%, saving the operator 18 days’ rig
time at $81,250/day for a total savings of $1.3 million.

SLIMHOLE DRIVE ANALYSIS
The above case studies document the successful application of the turbine power section when run with an impregnated or PDC bit. However, to fully understand the performance capabilities of the different types of turbines, an in-depth analysis was performed and revealed that slimhole positive displacement motors and T1 turbodrills achieved similar results compared with offsets when run in combination with a Smith Kinetic (KGR) diamond impregnated bit.

The T1 turbine requires four times the power output to match the positive displacement motor’s horsepower due to differences in the drilling systems. However, by extracting the dissimilar 5-in. and high-RPM motor runs from the data set, the T1 turbine is highly competitive (Figure 4). It’s interesting to note that approximately 50% of KGR impregnated runs on low-powered drives perform below expectations. It appears more power is necessary to achieve the desired ROP gains.

POWER = PERFORMANCE
Based on the T1 turbine vs motor power/performance analysis, engineers determined the T2 high-power turbodrill offers a better opportunity to improve ROP performance over PDM products. The T2 turbine was run 14 times in various US locations and delivered differentiable results compared with motor performance (Figure 5). As a general rule, for each additional one horsepower generated above the 175-hp benchmark, the operator can expect a 1% increase in ROP compared with the best-performing motor driven offset.

FUTURE IMPROVEMENTS
The future of turbine drilling to help recover deeply buried reservoirs looks promising. With increased R&D funding, the service provider plans to improve existing turbodrill technology to provide more horsepower, RPM and torque through improved blade efficiency, advances in hard material science and bearing reliability.

There is also an initiative to develop a broad range of application-specific turbobit optimized bit technology to expand the turbine/fixed cutter BHA application envelop into formations traditionally drilled with a motor and PDC bit.

CONCLUSIONS
The key to improving performance in deep HPHT applications is using a systems approach to fine-tune the bit and turbine for the specific application. These variables include turbodrill blade type, stage count and system flow rate based on mud properties including weight (ppg) and type (OBM, SBM, WBM). For any application, the turbine’s power output can be optimized to accommodate the specific bit type (PDC or impregnated) and formation lithology/variables.

By utilizing the increased power, RPM and torque potential of turbodrill technology, operators can take the first step toward increasing the economic feasibility of drilling deeply buried reservoirs with the minimum number of trips at the highest possible ROP.

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References