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Match drill bit designs to specific drilling systems

A bit should be designed to complement the unique qualities and capabilities of each individual drilling system.

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To maximize drilling efficiency, both the bit and drilling system have to be considered.

Engineers in Varel's research and development group use field run data and laboratory tests to create a guideline matrix to help design the most effective bit for the drilling system. This matrix takes into account the system type — point the bit or push the bit — as well as the power generated and drilling characteristics delivered by the tool.

Varel's Navigator bits are custom designed to the operator's specific directional profile. To do this, engineers consider the operator's parameters for dogleg severity, borehole quality and rate of penetration (ROP). The bit's ability to achieve a given wellbore objective relies upon two key design factors: stability and directional behavior (steerability and walk angle).

When designing bits for directional drilling systems, engineers pay particular attention to the gage. The gage is what gives the bit its aggressivity and steerability. It is imperative to design the gage to complement the drilling system. For example, we don't want to design an extremely aggressive bit for a drilling system that has a propensity to "walk" — this pairing would make the bit too aggressive, making it too difficult to control the bit, which will result in low performance or missing the target. Pairing the drill bit to the drilling system is the key to a successful bit run.

Proprietary design tools

In addition to the above, all bits are designed using the company's proprietary design software tools, GeoScience and SPOT, as well as a computational fluid dynamics (CFD) program to determine the most effective hydraulic package. GeoScience is the company's in-house lithology and rock strength determination software and a log analysis method for improving bit selection and optimization. GeoScience can be used as a pre-well or post-well analysis as it develops information about formation type, abrasivity, porosity, drillability and many other formation data parameters. When designing a bit, such information is then entered into SPOT, the company's proprietary software that uses algorithms from laboratory and field data to model forces acting on the bit that affect its behavior and assures optimal performance.

SPOT is essentially a drilling simulator that allows virtual bit tests. In the case of a bit developed for Chesapeake Energy for the Barnett Shale, it took SPOT about 20 seconds to generate informational output for the 8½-in. bit drilling a simulated 4,000-ft (1,220-m) lateral interval. SPOT outputs certain parameters, including weight on bit required to drill, torque required to rotate the bit, lateral aggressivity, axial aggressivity, cutter wear and many other drilling parameters and bit factors.

The output from SPOT allows engineers to examine different cutting structure layouts and cutter placement. Different designs can be viewed simultaneously, enabling engineers to alter a design in order to optimize the cutting structure. Once the bit's profile is determined and the cutting structure is designed, CFD software is used to determine the best nozzle orientation to optimize bit hydraulics.

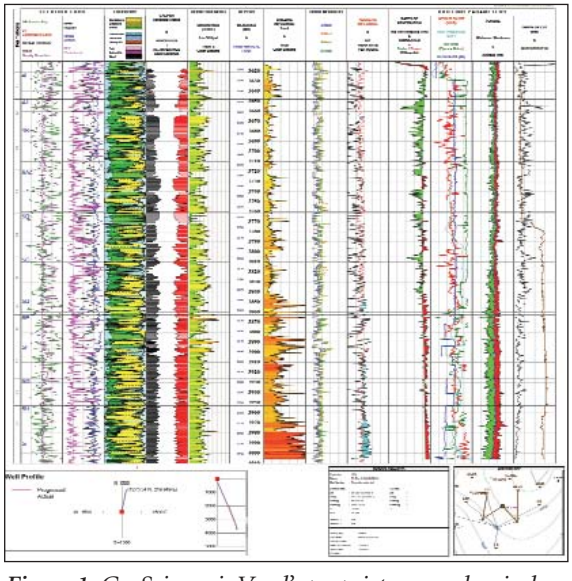

Figure 1. GeoScience is Varel's proprietary mechanical rock properties model that uses well logs. Output from GeoScience is fed into the design process through the SPOT product simulation tool, allowing bit designers to accurately model bit dynamics. (Image courtesy of Varel)

Barnett Shale performance

The company worked with Chesapeake Energy to customize an 8½-in. VM519HU bit. At the time, Chesapeake was drilling the 4,000-ft lateral section in about four days. Based on offset data from two nearby wells drilled with another drill bit, the new bit increased ROP by 13% to 55.42 ft/hr and drilled a 4,018-ft (1,225.5-m) lateral section in 72.5 hours. Additionally, the new PDC bit drilled 7.03% longer than the best given offset. The bit was run on a second Chesapeake well in which ROP was 35.38% faster than the best given offset. E&P