UNCONVENTIONALS

CASE STUDY

Integrated Approach to Fluid Performance Reduces Days on Well by 30 Percent

REAL-TIME MONITORING AND OPTIMIZED FLUID PROPERTIES ELIMINATE STUCK PIPE AND HIGH NPT COSTS

MARCELLUS SHALE FORMATION, PENNSYLVANIA

CHALLENGES

- Drill to TD despite complicated directional design
- Improve wellbore instability
- Prevent tight-hole and stuck-pipe incidents
- Drill casing to bottom on every well
- Avoid NPT

SOLUTIONS

- BaraLogix® real-time and automation services for optimal hydraulics management
- Organophilic clay-free BaraXcel™ high-performance NAF for improved ECD control
- DFG RT™ drilling fluids graphics software to model downhole conditions and drilling parameters
- Three BaraG-Force™ variable-frequency, high-performance large-bowl centrifuges, along with two barite recovery units and one polisher

RESULTS

- Achieved a 30 percent reduction in drilling time, casing-to-casing
- Drilled record-setting fastest wells, with the longest laterals
- Recorded zero NPT associated with wellbore instability
- Successfully ran casing to bottom on every well
- Saved operator a total of USD 600,000 in rig time over a six-well campaign

OVERVIEW

An operator in northern Pennsylvania drills wells in a highly fractured area of the Marcellus shale. These lateral sections – which kick off at 8,800 feet (2682 meters) true vertical depth (TVD), with a horizontal displacement of 6,000–8,300 feet (1829–2530 meters) – travel through complex geology. Severe wellbore instability issues often caused stuck pipe, lost bottomhole assemblies (BHAs), sidetracks, and failure to get casing to bottom, as well as high drilling fluid and overall well costs. The operator believed that applying predictive modeling for pressure management would help eliminate issues encountered on previous wells.

CHALLENGES

To maximize reservoir contact, the directional drilling plan incorporated frequent inclination changes (e.g., 70° followed by 120°). Tight-hole and stuck-pipe incidents occurred frequently in the 8.5-inch production interval. When the operator was able to reach the target total depth (TD), tripping out of the hole was difficult. Attempts to run 5.5-inch casing through the production interval often ended off bottom.

As the operator tried to reduce wellbore instability, mud weights could range from 13 pounds per gallon (ppg) to 18 ppg, but there was uncertainty about equivalent circulating density (ECD) and maintaining desirable mud properties. The drilling fluid typically exhibited a high concentration of low gravity solids (LGS), which made ECD control difficult.

SOLUTIONS

SAVED
USD 600,000
OVER A SERIES OF WELLS

Baroid provided three fluid management strategies that would minimize or eliminate the series of problems caused by wellbore instability. The Baroid team installed a BaraLogix® density and rheology unit at the rigsite for continuous rapid sampling of density and rheology in real time. The data was streamed to the teams on the rig, to the BaraLogix real-time monitoring service personnel, as well as to the drilling engineers' mobile devices. This data formed the basis for highly accurate modeling that would help the operator predict potential trouble areas.

DFG RT™ drilling fluids graphics software was used to continually model downhole conditions and drilling parameters in order to optimize hole cleaning, trip schedules, and predictive capabilities concerning potential issues arising ahead of the bit.

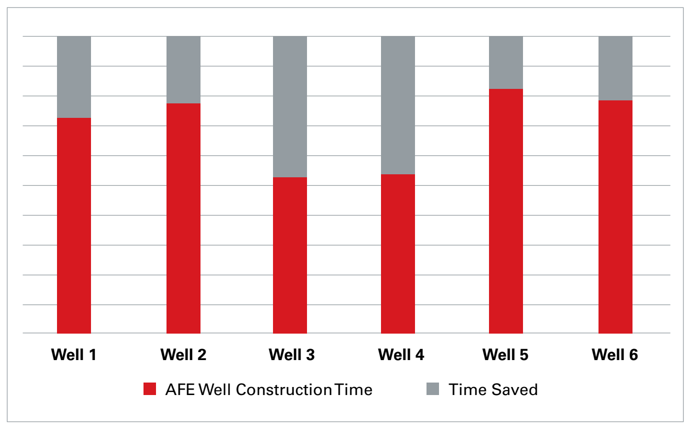
To improve ECD management and minimize solids content, Baroid implemented its BaraXcel™ high-performance, non-aqueous fluid (NAF). BaraXcel NAF is ideal for use in naturally fractured formations where ECD is a constant concern. The rheology modifiers are polymer-based rather than slow-yielding, inefficient organophilic clay. This helps optimize hydraulics and ensure effective hole cleaning.

The third part of the integrated approach to fluid management focused on improving solids control efficiency and reducing the LGS concentration. The selected equipment would provide reliable throughput of 16-ppg NAF and good barite recovery to help decrease fluid treatment costs. The team designed a customized system consisting of three BaraG-Force™ variable-frequency, high-performance large-bowl centrifuges, including two barite recovery units and one polisher.

BaraLogix® real-time monitoring helped the operator optimize drilling parameters.

RESULTS

Access to real-time NAF properties, along with continual BaraLogix real-time monitoring from Baroid personnel, allowed the customer to make more informed decisions about all aspects of the drilling operation. The actual ECD value was known at all points in the well construction process, and could be adjusted on the fly as needed. To assist with ECD management, a 6.7 percent LGS average for the project was maintained, using the three centrifuges.



Based on the operator's AFE time allocation, all six wells were drilled significantly faster than planned.

The operator began drilling its fastest and longest laterals to date, while reducing the days on well by 30 percent as compared to an aggressive Authorization for Expenditure (AFE) target. The operator was able to trip drillpipe out of the hole during trips with no issues, and production casing was run successfully to bottom on every well with zero non-productive time (NPT) associated with wellbore instability or a complicated well design.

Over a six-well campaign, using the Baroid integrated approach, the operator saved a total of USD 600,000 in rig time alone.

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