Fiber-Based Frac Fluid A Hit In Bakken

By Al Powell, Oscar Bustos, Bill Morris and Walt Kordziel

HOUSTON—Hydraulic fracturing has become one of the most effective tools for reservoir management. Proper stimulation through hydraulic fracturing enables producers to bypass skin damage and create a high conductive flow path for hydrocarbons, thereby accelerating the recovery of reserves and enabling production of unconventional reservoirs at economic rates.

Tight gas sands and unconventional formations (for example, the Barnett Shale) may have only marginal producing potential under normal conditions, even with no formation damage. However, hydraulic fracturing has played a major role in turning such provinces into attractive exploration and production opportunities.

It is estimated that more than 80 percent of the wells in the continental United States receive hydraulic fracture treatments, and treatments typically represent 10-30 percent of overall well costs. Hence, improvements in fracturing efficiency have meaningful scope, whether in greater well production or lower treatment cost.

A good example comes from a series of hydrofraced wells operated by Headington Oil Company in the Bakken formation of the Williston Basin on the North Dakota-Montana border. These horizontally drilled wells in the Bakken typically cost from $4 million to $6 million through completion and stimulation. Using a new fiber-based fracturing fluid, Headington achieved substantial improvements in fracture effectiveness and the relative cost of the frac treatments. The results, which were compared with those from previous hydrofracs in offset wells, included:

- Improved proppant transport and placement with no proppant settling;
- Enhanced zone coverage by replacing soluble ball sealers with fiber technology to induce diversion from both natural and induced fractures;
- A more than 40 percent reduction in polymer usage;
- Elimination of sand production and post-fracture well bore clean-outs, expediting time to sales by seven days;
- Propped fractures with longer effective half-lengths and greater conductivity; and
- Production increases averaging nearly 25 percent greater than comparable offset well treatments.

Bakken Dolomite-Shale Play

The Bakken play is an unconventional oil reservoir that crosses the border of Montana and North Dakota. It is a Mississippian-Devonian formation with three informal members: upper and a lower black, organic-rich shales separated by...
an arenaceous dolomite, grading to siltstone. The most prolific area is situated in Richland County, Mt. Drilling activity there goes back as far as 1953, when the Antelope Anticline was discovered.

The basin continued to be exploited over the next several decades, but the economic potential of the Bakken was not achieved until horizontal drilling began to take advantage of the thin, naturally fractured formation characteristics. Horizontal wells in the Bakken have increased from 229 in 2000 to more than 400 with 50 rigs drilling this fall.

With the evolution of new horizontal multilaterals has come an evolution of innovative completion and stimulation practices, including a conversion from oil-based fracturing fluids in many instances to more environmentally friendly and cost-saving water-based fluids coupled with fiber technology.

Exploration and exploitation have shifted into the North Dakota extension of the Bakken, where reservoir quality is not as good. The stress profile of the overlying formation, for example, suggests less fracture height containment. Oil saturation, matrix porosity, and formation thickness are more variable. However, the play’s areal extension is larger, making it a more attractive target for future development.

The generic reservoir properties of the Bakken Shale are:
- True vertical depth is approximately 10,300 feet.
- Measured depth is from 13,000 to 19,000 feet.
- Lateral lengths range from 3,000 to 9,000 feet.
- Well types include single-, dual- and tri-laterals.
- Completion type is uncedmented, preperforated liner in the horizontal section and open-hole completion.
- Net thickness is 5-20 feet.
- Reservoir pressures run from 5,100 to 7,200 psi.
- Permeability is 0.01-1.00 milliDarcy.
- Porosity is 7-16 percent.

With proppant transport no longer tied to fluid viscosities, transport can be customized to reservoir conditions for optimal fracture geometry. Fracture-height growth can be contained, if needed, by using low-viscosity fluids—even at high temperatures—with effective proppant transport throughout the process.

Additionally, it is possible to achieve a significant increase in retained proppant-pack permeability as a result of lower polymer loading and better proppant distribution. Based on laboratory testing, a 40 percent decrease in polymer loading has been shown to yield a 24 percent increase in retained permeability with no adverse effects from the fibers on either retained proppant-pack permeability or fracture conductivity (Figure 1).

**Headington’s Fracture Operations**

Headington was conducting a multi-stage hydraulic fracturing operation in horizontal multilateral wells drilled into naturally fractured shale-dolomite within in the Bakken play (Figure 2). Laterals, completed with preperforated liners, extend 5,000-9,400 feet into the formation, which has a permeability of 0.1-0.9 mD and average porosity of 9 percent. Bottom-hole static temperatures average 240 degrees F.

Headington needed a stimulation program to maximize fracture conductivity and improve flow convergence in an en-

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*Pounds of proppant added per gallon of fluid
FIGURE 4
Cumulative Production Comparison from McKenzie County, N.D.
(Three Wells Treated with Fiber-Based Fluid versus Seven Offset Wells)

![Graph showing cumulative production comparison between FiberFRAC wells and Offset wells over 12 months.](image)

Environment where previous, traditional fracturing treatments had resulted in proppant settling, poor proppant placement, formation damage caused by sand production, significant well bore cleanout requirements, and in summary, underperforming wells.

Conventional treatment design in these earlier wells encompassed five to seven fracturing cycles along each lateral with bio-ball sealers used to divert fluids. The fracturing fluid used in these treatments consisted of a 35 pounds per 1,000 gallons of borate delayed, cross-linked guar. Because cross-linked fluids are designed to break down shortly after pumping, the remaining low-viscosity fluid was unable to suspend the proppant while the fracture was still open.

Seeking improved results, Headington conducted a series of treatments using the fiber-based fracturing fluid technology for proppant transport and fluid diversion. These treatments have been performed on more than 200 laterals. Using this technology has allowed Headington to reduce its polymer concentration by 43 percent, to 20 pounds per 1,000 gallons.

Widely varying pump schedules have been used throughout the Bakken, and each operating company has its own schedule guidelines. However, treatments generally consist of a series of pad/sand ramp-up sequences repeated a number of times, depending on lateral length.

For example, a job plot from one of the fiber-based treatments shows a proppant concentration as high as five pounds of proppant per gallon of fluid, using a total of 9,000 barrels of water-base gel and 875,000 pounds of 20/40 sand. Table 1 provides an example of a single frac cycle in a typical fiber-based fluid treatment. As many as 20 such cycles are pumped continuously.

Figure 3 represents the bottom-hole pressure calculation for a well in which the fiber-based fracturing fluid was used. Note that the difference between initial instantaneous shut-in pressure and final instantaneous shut-in pressure is more than 1,600 psi, and the overall bottom-hole pressure trend is positive, which could be an indication of diversion effectiveness.

Treatment Results

In the wells treated with the fiber-based fluid, significantly improved proppant transport and placement were noted, compared with traditionally treated wells. No proppant settling was observed in fiber-laden surface samples taken after four hours. With less polymer used, higher retained proppant pack permeability was achieved, and sand production and subsequent well bore clean-out also were eliminated, minimizing completion costs and the time to sales, as well as any formation damage caused by a clean-out.

Longer effective half-lengths were observed in the fiber-treated fractures, with more of each propped fracture contributing to production. Headington recorded an average 24 percent production increase in the wells receiving the fiber-based treatment fluid compared with conventionally treated offset wells in both Montana and North Dakota. More specifically, Figure 4 graphs the cumulative production from three wells completed with the fiber-based fluid technology in McKenzie County, N.D., compared with cumulative production from seven offset wells that were completed using conventional fluids.

Headington Oil Company has used fiber-based fracturing fluid on more than 200 horizontal wells in the Bakken formation to achieve substantial increases in production compared with traditional fracture treatments on offset wells. Improved proppant transport and placement occurred in these treatments, with no proppant settling or flowing back, and fracture conductivity was increased.

At the same time, treatment footprints have been greatly diminished through a major reduction in necessary polymer levels, which translates to reduced formation damage and less need for post-treatment well bore clean-outs. Decreasing polymer requirements and eliminating ball-sealer fluid diverters by using the fiber technology as a diverting agent has further reduced the cost profile of the Bakken treatments.

Based on these factors, fiber-based fluid offers a promising method for significantly improving the efficiency of hydraulic fracturing treatments and helping the industry enhance the effectiveness of this important, widely used stimulation technique.

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