New Fibers for Hydraulic Fracturing

Efficient proppant transport is essential to successful hydraulic fracturing. While conventional fracturing fluids rely on high fluid viscosities, a new approach employs synthetic fibers that provide excellent proppant transport at low fluid viscosities. This technology, which has improved well productivity in several fields, gives engineers more flexibility when designing fracturing treatments.

Fibers have been used in industry since antiquity. Ancient Egyptians used straw and horsehair to reinforce mud bricks. Early Chinese and Japanese houses show evidence of straw mats to provide structural support. However, until synthetic fibers became commercially available during the early 20th Century, commercial applications were limited by the properties of naturally occurring fibers.

Today, a wide variety of manufactured fibers is available, mostly made from polymers, metals, glass or carbon. These fibers have properties that are revolutionizing many industries, particularly civil engineering, medicine, apparel and transportation. The oil and gas industry, especially the pumping-services sector, is also benefiting from new fibrous materials.

In the 1960s, engineers began adding nylon fibers to well cements for structural reinforcement. The fibers transmit localized stresses more evenly throughout the cement matrix; as a result, the hardened cement is less susceptible to stress cracking and shattering during perforating.

In the 1990s, Schlumberger introduced CemNET advanced fiber cement, which employed glass fibers to prevent lost circulation. As a CemNET cement slurry flows across a lost-circulation zone during primary cementing, the fibers form a bridging network and limit slurry loss from the annulus to the formation. This technology helps operators fill the annulus completely with cement, improving zonal isolation and avoiding remedial cementing.

Fibers are also used to prevent proppant flowback, a serious problem associated with hydraulic fracturing. If proppant flows out of a hydraulic fracture into the casing, well productivity declines, and damage to casing, control valves and wellhead equipment may
result. Pumped together with proppant in a fracturing fluid, the fibers form a network that stabilizes the proppant pack (below). To maintain proppant-pack integrity, the fibers must be sufficiently stable to remain in place during the productive life of the well. Today, three PropNET hydraulic fracturing proppant-pack additives, made from glass or polymer fibers, address a wide variety of well conditions.

Recently, Schlumberger researchers discovered that, in addition to stabilizing a proppant pack, fibers could enhance the proppant-transport capabilities of fracturing fluids. Development of this concept in both the laboratory and the field resulted in the introduction of FiberFRAC fiber-based fracturing fluid technology.

This article describes how fibers improve proppant transport, discusses the practical advantages of using fibers, and shows how the technology can be employed to improve hydraulic fracturing treatments. Case histories from California, east Texas, the US midcontinent, and northern Mexico illustrate the benefits of the fiber technology.

How Fibers Prevent Proppant Settling

Hydraulic fracturing treatments comprise two basic fluid stages. The first stage, or pad, does not contain proppant, and is pumped through casing perforations at a rate and pressure sufficient to break down the formation and create a fracture. The second stage, or proppant slurry, transports proppant through the perforations into the open fracture. When pumping ceases, the fracture closes onto the proppant.

During injection and fracture closure, the rate of proppant settling greatly influences the final propped-fracture geometry. High settling velocities cause proppant to concentrate at the bottom of a fracture before it closes. In extreme cases, the proppant particles form clusters that prevent further fluid injection. In either situation, proppant does not completely fill the fracture, and well productivity suffers. By contrast, low settling velocities promote a complete and uniform distribution of proppant throughout the fracture.

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5. Proppants are sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for fluid flow from the reservoir to the wellbore.
Proppant transport in conventional fracturing fluids is governed by a complex combination of parameters, including particle size and density, fracture dimensions and base-fluid rheological properties. Fluid viscosity is particularly important because it provides resistance to gravitational settling, and helps transport the proppant along a fracture. Several studies have investigated proppant-settling rates versus fluid viscosity. One overarching fluid-viscosity guideline has emerged from these studies and field experience: for conventional fracturing fluids, the minimum fluid viscosity to ensure adequate proppant transport is about 100 cP at 100 s⁻¹ shear rate.

Fracturing-fluid viscosity also affects fracture geometry. As fluid viscosity increases, fracture width increases. Unfortunately, the bottomhole treating pressure also increases, potentially causing excessive vertical fracture-height growth. If the fracture grows beyond the pay zone into nonproductive or water-producing intervals, the overall efficiency of the fracturing treatment suffers (above).

Therefore, engineers must design fracturing fluids that transport proppant efficiently, while keeping fractures within the pay zones. In many areas, achieving both goals is difficult, which sometimes forces engineers to make compromises that lead to suboptimal results. Fortunately, fibers offer a solution to this dilemma.

Adding fibers to a fluid-particle suspension dramatically alters particle-settling behavior. When fibers are not present, settling generally proceeds according to Stokes’ law. The speed at which particles fall through a fluid is directly proportional to particle size and density, and inversely proportional to fluid viscosity. As sedimentation proceeds, a distinct boundary forms between the particle bed and the fluid lying above.

With fibers present, Stokes’ law no longer applies. The fibers interfere with the particles, physically hindering their downward journey. As sedimentation proceeds, a distinct particle-liquid boundary does not develop; instead, the fiber-particle mixture slowly compresses, leaving little fluid behind. This type of behavior is called Kynch sedimentation (next page, top).

The practical benefit of Kynch sedimentation is that fluid viscosity plays a much smaller role in determining the particle-settling velocity. Experiments show that, at a given base-fluid viscosity, fibers reduce the proppant-settling velocity by more than one order of magnitude. Equivalently, at a given settling rate, the required base-fluid viscosity also decreases by about one order of magnitude (next page, bottom). Indeed, in terms of particle sedimentation, one may think of the fibers as providing virtual fluid viscosity. Use of FiberFRAC technology reduces the importance of base-fluid viscosity as a settling-rate determinant, giving engineers much wider latitude when designing a fracturing treatment.
Optimizing Fibers for Proppant Transport

Appropriate fibers for proppant transport must have the correct combination of length, diameter, flexibility and temperature stability. The fibers must be easy to disperse in a proppant slurry, and able to pass through pumping equipment, tubulars and perforations without breaking or bridging. The fibers cannot separate from the proppant during placement. After placement, the fibers must be stable until the fracture closes. However, unlike PropNET fibers, proppant-transport fibers should dissolve after fracture closure to maximize proppant-pack conductivity.

Schlumberger scientists experimented with many types of fibers before finding products that satisfied all these requirements. They chose two fibers that cover two reservoir-temperature ranges: 150°F to 250°F [66°C to 121°C] and 250°F to 400°F [204°C]. During the development of FiberFRAC technology, two laboratory evaluations were particularly important: the slot test and the proppant-pack conductivity test.

A slot test is a dynamic laboratory technique to evaluate proppant transport. The test apparatus has a transparent slot that simulates an 8-ft long, 1-ft high and 5⁄16-in. wide [2.44-m by 30.4-cm by 0.47-cm] fracture. Proppant slurry flows through an orifice simulating a perforation and then passes across the slot, permitting observation and measurement of proppant-transport efficiency. One test compared the performance of conventional and FiberFRAC slurries, each using the same base fluid. Proppant of 20/40-mesh size was added at a

10. Shear rate, $\dot{\gamma}$, is the velocity gradient measured across the diameter of a fluid-flow channel, such as a pipe, annulus or other shape. In most oilfield viscometers, the shear rate is the velocity difference between a rotating sleeve and a cylinder (or bob) mounted concentrically inside the sleeve. When fluid is present in the annulus between the bob and the sleeve, the bob experiences torque as the sleeve rotates. This force is called shear stress, $\tau$. Viscosity, $\mu$, is the shear-stress to shear-rate ratio, $\mu = \tau/\dot{\gamma}$. The viscosity of many fluids varies with shear rate. Therefore, viscosity specifications must include the shear rate. In this article, the shear rate for all viscosities is 100 s⁻¹.
concentration of 2 lbm [0.9 kg] to each gallon US [3.8 L] of fracturing fluid (2 ppa). The pump rates for the conventional and FiberFRAC slurries were 26.6 and 17.4 gal/min [101 and 66.1 L/min], respectively. Despite the higher pump rate, proppant in the conventional fluid separated and fell to the bottom of the slot. The FiberFRAC slurry was stable, fibers were evenly dispersed, and all proppant remained in suspension during the test (left). In addition, the fibers did not break or bridge while passing through the perforation.

Proppant-pack conductivity is a direct function of the void space between the proppant particles; therefore, it would be best if the FiberFRAC fibers disappeared. Unlike PropNET fibers, which must maintain a rigid network, FiberFRAC fibers are no longer needed after proppant-slurry placement and fracture closure. For this reason, Schlumberger scientists chose polymers that slowly dissolve (below left). Laboratory testing confirmed that, once the fibers dissolved, the resulting proppant-pack conductivity was essentially identical to that obtained from the same fluid without fibers (next page, top).

Wellsite Delivery

Proper execution of a hydraulic fracturing treatment requires smooth and stable mixing of all fluid components at the correct concentrations. Fibers have a high length-to-diameter ratio; consequently, adding and dispersing them in a proppant slurry may be a challenge. Fortunately, this problem was addressed previously, during the development of PropNET technology. The POD programmable optimum density blender is equipped with a special feeder for adding fibers to fracturing fluids (next page, bottom). This feeder comprises a hopper into which the fibers are poured, and an auger that blends the fibers into the proppant slurry at a steady rate. During large treatments, a conveyor belt transports fibers into the feeder.

The physical and chemical properties of FiberFRAC fibers differ from those of PropNET fibers. Therefore, before pumping actual treatments, mixing tests were necessary to verify the suitability of the existing feeder on a POD blender. Minor auger recalibration compensated for the different bulk density and flow properties of dry FiberFRAC fibers. Actual field treatments could then proceed.

12. Proppant concentrations are commonly expressed in "pounds of proppant added," or ppa. One ppa means that one pound of proppant is added to each gallon of fracturing fluid. It must not be confused with the more common "pounds per gallon," or lbm/gal. During hydraulic fracturing treatments, ppa better reflects field practice. There is no recognized metric equivalent to ppa.
Effect of FiberFRAC fibers on proppant-pack conductivity. The conductivity test (right) involves placing a proppant slurry between two cores, and inserting the proppant “sandwich” in a conductivity cell. The cores are heated and compressed in the cell to simulate downhole conditions, and fluid from the proppant slurry leaks off through the cores. After leakoff, brine is pumped through the proppant pack, and the pressure drop is recorded. FiberFRAC fibers have a minimal effect on the proppant-pack conductivity (left). In these experiments, the proppant was 20/40-mesh bauxite, and the closure stress was 5,000 psi [35 Mpa].

Wellsite delivery. A hopper above the POD programmable optimum density blender feeds fibers into the fracturing fluid.
Stimulating the Monterey Formation in California

Chevron initiated the first applications of FiberFRAC technology at the Lost Hills field in California, USA. The oil-producing Monterey formation is composed of diatomite with a high porosity—45 to 65%—and a relatively low permeability of 1 to 7 mD. The reservoir pressure ranges from 500 to 1,400 psi [3.5 to 9.8 MPa], at an average bottomhole temperature of 125°F [51.7°C]. The pay zone is 800 to 1,200 ft [152 to 366 m] thick at an average depth of about 1,800 ft [549 m]. The stress barriers lying above and below the pay zone are weak, and may not contain a hydraulic fracture.

The most interesting feature of this diatomite is its softness. The Young’s modulus is extremely low—50,000 to 300,000 psi [345 to 2,070 MPa]—about one order of magnitude less than that of hard sandstones.

These rock properties make conventional fracturing fluids difficult to use. The high viscosities of crosslinked fracturing fluids create excessive near-wellbore fracture width. Because of the weak stress barriers, there is little control of fracture height. Previous treatments with a conventional 350-cP [0.35-Pa.s] borate-crosslinked guar fluid system usually resulted in short, wide fractures that extended beyond the pay zone. This “ballooning” of the fracture also caused significant proppant-flowback problems.

Schlumberger engineers used the FracCADE fracturing design and evaluation software to determine the fluid properties required to create longer, narrower fractures that would be confined within the pay zone. The computer simulations predicted that the fluid viscosity should be less than 100 cP [0.1 Pa.s]. In light of the proppant-transport guidelines described earlier, Chevron stimulated the next group of wells with FiberFRAC technology. After preliminary laboratory testing, a 33-cP [0.03-Pa.s] linear (uncrosslinked) guar solution was chosen as the base fluid. The FracCADE simulator also showed that the FiberFRAC treatments would require less proppant, because the fractures would be narrower and confined within the pay zone.

The Lost Hills hydraulic fracturing program benefited from surface tiltmeter fracture mapping performed by Chevron while fracturing with conventional fluids. The company also installed tiltmeters during seven FiberFRAC treatments, giving engineers a rare opportunity to compare fractures created by both types of fluids.

The seven treatments involved multiple zones in two wells (top). Well A was treated in four stages, Well B in three. Bridge plugs provided zonal isolation between the stages. The perforations were oriented to induce fracture growth in the preferred direction.

The FiberFRAC treatments were pumped successfully, without fiber bridging at the perforations or difficulties placing proppant inside fractures. Analysis of the tiltmeter data showed that the average fracture length was 182 ft [55.5 m], compared to 145 ft [44.2 m] for the conventional treatments. As predicted by simulations, much less proppant was required to achieve the longer fractures: 1,700 lbm of proppant per foot of interval [2,530 kg per meter], compared with 2,100 to 2,500 lbm per foot [3,130 to 3,730 kg per meter] for the conventional jobs.

After 90 days, the production rates from wells treated with conventional and fiber-laden fluids...
were the same; however, the FiberFRAC wells required 30% less proppant. On a typical Lost Hills well, this is equivalent to obtaining the same production rates with 720,000 lbm [327,000 kg] less proppant (previous page, bottom). In addition, because of narrower near-wellbore fracture width, little or no proppant flowback occurred during production.

Improving Production in the Lower Cotton Valley Formation

The Lower Cotton Valley formation of east Texas and northern Louisiana, USA, consists of thin, laminated, gas-producing sandstones between shale layers. The permeability ranges between 0.001 and 0.05 mD. Gas-producing formations with such low permeabilities are often classified as tight gas. Reservoir depths range from 10,000 to 14,000 ft [3,048 to 4,270 m], and the bottomhole temperatures vary between 200 and 340°F [93 and 182°C]. The Young's modulus of the sandstone is 5,000,000 psi [34,470 MPa], more than one order of magnitude greater than the Lost Hills diatomite mentioned earlier.

For this geological situation, the main fracturing design challenges include the need for long fractures, limited fracture-height growth, good proppant coverage over the entire fracture surface and minimal proppant-pack damage. In addition, the fracturing fluid must be stable at high temperatures.

Many operators have performed conventional massive hydraulic fracturing treatments in this formation, using crosslinked polymer fluids. Unfortunately, these treatments often create large fractures that extend into nonproductive zones, and require large volumes of polymer and proppant, reducing the economic viability of stimulation.

On the other end of the viscosity spectrum, fracturing with slick-water—water plus a friction reducer—is a popular stimulation method for this formation.¹³ The viscosity of slick-water is about 1 cP. Exerting sufficient force to initiate and propagate a fracture during the pad stage, and to transport proppant, requires high pump rates, usually greater than 50 bbl/min [7.9 m³/min]. The proppant concentration in the fluid is low, usually less than 2 pp. The proppant size is usually small—40/70 mesh—to minimize the Stokes’ law settling rate. This method is much less expensive than massive hydraulic fracturing, and has greatly expanded the number of wells that can be economically stimulated. However, further investigations revealed that, when normalized for reservoir and producing-system conditions, wells stimulated in this manner were less productive than those treated conventionally.¹⁴ Despite the high pump rates, small proppant sizes and low proppant concentrations, proppant tends to settle relatively close to the wellbore, limiting the effective fracture length.

Neither conventional nor slick-water treatments can address all of the stimulation challenges posed by the Cotton Valley formation. This area requires a low-viscosity fracturing fluid that transports proppant efficiently. Following the success of fiber-laden fracturing fluids in California, FiberFRAC technology was proposed for the Cotton Valley formation.¹⁵ The first application occurred in the Okla field, operated by Bivins Operating Company. The producing reservoir depth was 13,000 to 14,000 ft [3,960 to 4,270 m], and the bottomhole temperature was 260°F [127°C].

Petrophysical analysis revealed that, because of the high Young’s modulus, the minimum fluid viscosity needed to achieve sufficient hydraulic fracture width for fiber placement was 50 cP [0.05 P.a.s]. To prevent excessive fracture-height growth, the upper fluid-viscosity limit was 150 cP [0.15 P.a.s]. At a fluid temperature of 260°F, a delayed borate-crosslinked guar fluid satisfied these requirements. The polymer concentration was 18 lbm/1,000 galUS [2.2 kg/m³]. Without fibers present, 30 to 35 lbm of guar per 1,000 galUS [3.6 to 4.2 kg/m³] would be necessary to achieve adequate proppant transport. In addition to reducing the fluid cost, using less polymer improves the proppant-pack conductivity and increases well productivity.²⁰

The FiberFRAC treatments were completed on a group of offset wells with similar lithological characteristics (left). The permeabilities and zone heights for both wells, collectively expressed as kh, were essentially the same: 0.30

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¹⁴. Young’s modulus, E, is an elastic constant that indicates how a material deforms when subjected to stress. Resistance of a material to deformation increases with the value of E.


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Image credits: Lithology of Wells 1 and 2 in the Lower Cotton Valley formation. The logs confirm a nearly identical sand series in the two wells.
and 0.28 mD-ft. Well 1 was treated with fiber-laden fluid; slick-water was used on Well 2. For Well 1, engineers pumped the 18-lbm/1,000 galUS borate-crosslinked guar system, and the proppant slurries contained 1 to 6 ppa 20/40-mesh sand. On average, 390,000 lbm [176,900 kg] of proppant were placed during each treatment. By contrast, the proppant slurries during the slick-water treatments contained 0.25 to 4 ppa 40/70-mesh sand, and the average amount of proppant placed was 200,000 lbm [90,700 kg].

Initial production from Well 1 was 3.1 million ft³/d [87,800 m³/d], while that from Well 2 was 0.70 million ft³/d [19,800 m³/d]. After 90 days of production, Well 1 produced at an average rate of 1.9 million ft³/d [53,800 m³/d], while the average production rate from Well 2 was 0.66 million ft³/d [18,700 m³/d]. During this period, the cumulative gas production from Well 1 was seven times greater than that of Well 2 (below).

To date, more than 120 FiberFRAC treatments have been performed in east Texas and Louisiana. More than 22 million lbm [10 million kg] of proppant have been placed, using more than 7 million gallons [26,500 m³] of fiber-laden fluid. Bottomhole temperatures varied between 197 and 339°F [93 and 182°C], with the majority pumped at about 265°F [129°C]. The largest fiber-laden treatment to date placed 850,000 lbm [385,000 kg] of proppant.

**Improving Gas Production in the Barnett Shale**

The Barnett shale is among the fastest growing onshore gas fields in the United States. Devon Energy operates 550,000 acres [222,530 ha] in the Fort Worth basin in northern Texas. The 200- to 600-ft [60-to 180-m] thick Barnett shale is even tighter than the Lower Cotton Valley sandstone. The permeability is 0.0001 mD, and the Young's modulus ranges from 2 to 3 million psi [13,790 to 20,680 MPa]. The average depth and bottomhole temperature are 8,000 ft and 200°F [2,440 m and 93°C], respectively.

The stimulation history of the Barnett shale is similar to that of the Lower Cotton Valley sandstone. Operators initially performed massive hydraulic fracturing treatments, involving fluids with high polymer concentrations and nearly 1.5 million pounds [680,400 kg] of proppant. The treatment costs were high, and the resulting production was often insufficient to justify commercial development of the Barnett shale.

To reduce treatment costs, many operators switched to slick-water fracturing fluids. Smaller sand treatments, usually involving about 200,000 lbm of proppant and increased liquid volume, were promising and greatly increased the number of wells that could be stimulated economically. However, certain areas did not fulfill their production potential. The estimated ultimate recovery (EUR) of the problem areas was generally greater than 1,000 million ft³ [28 million m³]. In these tight formations, fracture length largely determines well productivity. Because slick-water has limited transport capability, the effective fracture lengths were not sufficient to achieve the desired well productivity.

To obtain more effective proppant distribution and improve well productivity Devon Energy used fiber-laden fracturing fluids. The fracturing fluid was a borate-crosslinked guar system with a polymer concentration of 18 lbm/1,000 galUS. The proppant concentration varied from 0.5 to 3 ppa. The treatment placed 540,000 lbm [245,000 kg] of 20/40-mesh sand. Following the treatment,
production was monitored and compared with that of conventional slick-water treatments (previous page, bottom). During the first 80 days of production, the wells treated with FiberFRAC technology delivered an additional 25 million ft³ [708,000 m³] of gas compared with the offset wells.

**Improving Gas Recovery in Northern Mexico**

The Arcabuz-Culebra field, operated by PEMEX Exploración y Producción in northern Mexico, is part of the larger Burgos basin that extends into south Texas, USA. The pay zone is the Wilcox formation, a gas-producing sandstone that is frequently associated with water-producing intervals. Today, the basin produces around 1,000 million ft³/d, and PEMEX is working to double this production rate.

The Young’s modulus of the Wilcox sandstone is 4 to 4.5 million psi [27,580 to 31,030 MPa], and the permeability ranges from 0.001 to 0.05 mD. Most wells are drilled to depths of 9,500 to 9,800 ft [2,895 to 2,987 m], where the bottomhole temperature is about 250°F. These formation characteristics require a low-viscosity fracturing fluid to minimize fracture entry into the water-producing layers. Because of the low formation permeability, long fractures are needed to maximize well productivity. Therefore, Schlumberger proposed FiberFRAC technology as a solution.

The first treatment took place near offset wells with similar $kh$ values. The $kh$ value of Well 1 was 86.3 mD·ft, while that of Well 2 was 94.7 mD·ft. Before stimulation, Well 1 produced 300,000 ft³/d [8,500 m³/d] of gas, while Well 2 did not produce at all.

Well 1 was treated conventionally with a 30-lbm/1,000 galUS [3.6-kg/m³] borate-crosslinked guar system, placing 200,000 lbm of ceramic proppant into the fracture. The FiberFRAC treatment in Well 2 employed a less viscous, 20-lbm/1,000 galUS [2.4-kg/m³] boretos-crosslinked guar fluid and, like Well 1, 200,000 lbm of proppant were placed at concentrations ranging from 1 to 8 ppa. The pump rate for both treatments was 30 bbl/min [4.8 m³/min]. Following the treatments, the gas production rate from Well 2 was more than five times greater than that of Well 1. In addition, the water production rate from Well 2 was only half that of Well 1. In light of these results, more fracturing treatments with fiber-laden fluids are planned.

The Future of Fiber-Assisted Transport

The field application of FiberFRAC technology is still in its infancy; however, initial results confirm the promise demonstrated during laboratory development. Low-viscosity, fiber-laden fracturing fluids appear to be particularly appropriate for stimulating formations that require careful fracture-height control.

Fibers also provide mechanical support for the proppant as it travels down a fracture, maximizing the effective fracture length. This attribute is particularly valuable when stimulating low-permeability gas formations.

Fiber-laden fluids are probably not economically justifiable for stimulating wells with an EUR below about 1,000 million ft³ of gas. Under these circumstances, slick-water appears to be the more appropriate fracturing fluid.

An increasing number of fields could benefit from FiberFRAC technology. Candidate selection is presently under way in the US and Canadian Rocky Mountains, and in Russia. Further use of FiberFRAC technology will more clearly define the window of well conditions in which it is appropriate. — EBN