The oil and gas industry has witnessed a revolution in fluids technology for hydraulic fracturing. Starting in the mid 1980s, focused research led to major improvements in the performance of well stimulation fluids. Today, new additives and fluids are extending these capabilities and providing innovative solutions to nagging problems. The results are more efficient and cost-effective treatments for enhancing well produc-

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Hydraulic fracturing is one of the oil and gas industry’s most complex operations. This technique has been applied worldwide to increase well productivity for nearly 50 years. Fluids are pumped into a well at pressures and flow rates high enough to split the rock and create two opposing cracks extending up to 1000 ft [305 m] or more from either side of the borehole (right). Sand or ceramic particulates, called proppant, are carried by the fluid to pack the fracture, keeping it open once pumping stops and pressures decline.

What defines a successful fracture? It is one that:
• is created reliably and cost-effectively
• provides maximum productivity enhancement
• is conductive and stable over time.

This article describes today’s fracturing operations and the pivotal role played by the fracturing fluid. Then, it highlights four new fluid technologies that are improving fracture success and well economics.

1. For more on hydraulic fracturing:
Fracturing operation. Modern treatments rely on a variety of process-controlled mixing, blending and pumping equipment and computer monitoring and recording systems, which permit real-time decision making.
The Rock, the Mechanics and the Fluid

Historically, fracturing has been applied primarily to low-permeability—0.1 to 10 md—formations with the goal of producing narrow, conductive flow paths that penetrate deep into the reservoir. These less restrictive linear conduits replace radial flow regimes and yield a several-fold production increase (above). For large-scale treatments, as many as 40 pieces of specialized equipment, each with a crew of 50 or more, are required to mix, blend and pump the fluid at more than 50 barrels per minute (bbl/min) [8 m³/min]. Pumping may last eight hours with 1,000,000 gal of fluid and 2,000,000 to 4,000,000 lbm of proppant placed in the fracture (next page, left).

Until recently, treatments were performed almost exclusively on poor producing wells (often to make them economically viable). In the early 1990s, industry focus shifted to good producers and wells with potential for greater financial return. This, in turn, meant an increased emphasis on stimulating high-permeability formations.

The major constraint on production from such reservoirs is formation damage, frequently remedied by matrix acidizing treatments. But acidizing has limitations, and fracturing has found an important niche. The objective in highly permeable formations is to create short, wide fractures to reach beyond the damage. This is often accomplished by having the proppant bridge, or screen out, at the end, or lip, of the fracture early in the treatment. This "tip screenout" technique is the opposite of what is desired in low-permeability formations where the tip is ideally the last area to be packed.

Why the different approach? The answer is found in the relationship between fracture length and the permeability contrast between the fracture and the formation. When the contrast is large, as for low-permeability reservoirs, longer fractures provide proportionally greater productivity. Where the contrast is small, as in high-permeability formations, greater fracture length provides minimal improvement. Fracture conductivity is, however, directly related to fracture width. Using short—about 100-ft [30-m]—and wide fractures can prove beneficial.²

High-permeability formation treatments are on a far reduced scale. Only a few pieces of blending and pumping equipment are required, and pumping times are typically less than one hour, and often only 15 minutes. Fluid is pumped at 15 to 20 bbl/min [2.4 to 3.2 m³/min] with a total volume of 10,000 to 20,000 gal [37.9 to 75.7 m³] and total proppant weight of about 100,000 lbm [45,000 kg] (next page, left). This technique has been successful in the North Sea, Middle East, Indonesia, Canada and Alaska, USA.

While fracturing treatments vary widely in scale, each requires the successful integration of many disciplines and technologies, regardless of reservoir type. Rock mechanics experiments on cores, specialized injection testing and well logs provide data on formation properties. Sophisticated computer software uses these data, along with fluid and well parameters, to simulate fracture initiation and propagation. These results and economic criteria define the optimum treatment design. Process-controlled mixing, blending and high-pressure pumping units execute the treatment. Monitoring and recording devices ensure fluid quality and provide permanent logs of job results. Engineers tracking the progress of the treatment use graphic displays that plot actual pumping parameters against design values to facilitate real-time decision making. Production simulators compare treatment results with expectations, providing valuable feedback for design of the next job.

The fracture is created by pumping a series of fluid and proppant stages. The first stage, or pad, initiates and propagates the fracture but does not contain proppant. Subsequent stages include proppant in increasing concentrations to extend the fracture and ensure its adequate packing.

Fracturing fluid technology has also developed in stages. Early work focused on identifying which polymers worked best and what concentrations gave adequate proppant transport. Then, research on additives to fine-tune fluid properties hit high gear.
Much was learned, but what finally emerged was a huge array of complicated fluids—difficult to prepare and pump—and an amazing assortment of single-use additives (most had to be custom manufactured) that required expensive material inventories.

In the past ten years, a more productive research direction has emerged. Oil companies, service companies and polymer manufacturers have concentrated on the basic physical and chemical mechanisms underlying the behavior of fracturing fluids in an attempt to find improved approaches to fluid design and use. This initiative has led to major advances, including higher-performing polymers, simpler fluids, multifunctional additives and continuous, instead of batch, mixing. These developments have had a significant, beneficial impact on the industry.

Recent innovations are extending the state of the art in four areas:

• controlling fluid loss to increase fluid efficiency
• extending breaker technology to improve fracture conductivity
• reducing polymer concentration to improve fracture conductivity
• eliminating proppant flowback to stabilize fractures.

Each provides new opportunities for improving well economics, as described in the remainder of this article.

Controlling Fluid Loss
A portion of the fluid pumped during a fracturing treatment filters into the surrounding permeable rock matrix. This process, referred to as fluid leakoff or fluid loss, occurs at the fracture face. The volume of fluid lost does not contribute to extending or widening the fracture. Fluid efficiency is one parameter describing the fluid’s ability to create the fracture. As leakoff increases, efficiency decreases. Excessive fluid loss can jeopardize the treatment, increase pumping costs and decrease post-treatment well performance.

Typically, particulates or other fluid additives are used to reduce leakoff by forming a filter cake—termed an external cake—on the surface of the fracture face. Acting together with the polymer chains, the fluid-loss material blocks the pore throats, effectively preventing invasion into the rock matrix.

This approach has been applied successfully for decades to low-permeability reservoirs, the invaded zone may be small or nonexistent, since polymer molecules are too large to enter the matrix. In these cases, an external filter cake controls fluid loss. In high-permeability reservoirs, significant matrix damage can occur because of particle penetration.


5. Fluid efficiency, \( E \), is defined as

\[
E = \frac{V_F}{V_T} = \frac{V_F}{V_T + V_L}
\]

in which \( V_F \) is the fluid volume remaining in the fracture, \( V_T \) is the total volume pumped and \( V_L \) is the volume of fluid that has leaked into the formation.
Dynamic fluid-loss measurements were made in the Dowell laboratory in Tulsa, Oklahoma, USA using special fluid-loss cells with a slot-flow geometry and a porous test surface on one of the slot walls (above). Cylindrical cores of the same type and dimensions as for static tests are used to allow direct comparison with static fluid-loss results. Cells are constructed from stainless steel for operation to 3500 psi and 350°F [177°C]. The inlet design ensures fully developed flow over the test section. A backpressure regulator and a heat exchanger, which cools the filtrate, prevent evaporation of the filtrate during operations above the ambient boiling point of the fluid. As many as three cells can be used simultaneously for testing cores of differing permeabilities.

A special fluid-loss simulator was designed to prepare the fluids under dynamic conditions, subject them to shear and temperature histories and then measure fluid loss (right).

The two components of the apparatus are a shear history simulator and a fracture simulator. The first uses a static mixer and 800 ft [244 m] of small-diameter tubing to simulate preparation and shearing of the fluid in the well tubulars. The second subjects the fluid to shear and temperature conditions of the fracture, using two large, floating-piston accumulators and coils of tubing immersed in a temperature-controlled bath. A computer-controlled valving arrangement ensures that the fluid always travels in the same direction across the core face.
Forces acting on a particle. A particle, such as a fluid-loss additive, flowing inside a fracture is subjected to shear, \( F_x \) and drag, \( F_y \), where \( v_x \) is the velocity in the flow direction as a function of the distance, \( y \), from the fracture face. The ratio of shear to drag is directly proportional to the leakoff rate and inversely proportional to the particle size and the shear rate at the wall. High initial leakoff and optimized particles can help ensure that fluid-loss additives reach and remain on the fracture face.

Shear rate history of a rock segment. As the tip of the fracture passes a particular location, in this case a point 50 ft [15 m] from the wellbore, the maximum shear rate occurs. As the treatment progresses and the fracture widens at this location, the shear rate falls off rapidly initially and then more slowly later. The laboratory approximation and the calculated curve show good agreement.

Classic fluid-loss theory assumes a two-stage, static—or nonflowing—process.\(^7\) As the fracture propagates and fresh formation surfaces are exposed, an initial loss of fluid, called spurt, occurs until an external filter cake is deposited. Once spurt ceases, pressure drop through the filter cake controls further leakoff. For years, researchers have developed fluid-loss control additives under nonflowing conditions based on this theory.

The conventional assumptions, however, neglect critical factors found under actual dynamic—or flowing—conditions present during fracturing, including the effects of shear stress on both external and internal filter cakes and how fluid-loss additives move toward the fracture face. In high-permeability formations, with an internal filter cake present, most of the resistance to leakoff occurs inside the rock, leaving the external cake subject to erosion by the fluid.

Analysis of fluid loss under dynamic conditions relates external cake thickness to the yield stress of the cake at the fluid interface and the shear stress exerted on the cake by the fluid.\(^8\) These, in turn, depend on the physical properties of the cake and the rheological properties of, and shear rate induced in, the fluid.\(^9\) Whether an external filter cake forms, grows, remains stable or erodes depends on the way these parameters vary and interact over time and spatial orientation.

Similarly, the effectiveness of additives to control fluid loss depends on two factors: their ability to reach the fracture face quickly and their ability to remain there. The former is governed by the drag force exerted on the particles and the latter by the shear force exerted on them (right). The larger the ratio of drag to shear, the greater the chance that the particles will remain on the surface. A greater leakoff flux to the wall, smaller particle dimensions and a lower shear rate favor sticking. Promoting higher leakoff for better additive placement seems directly at odds with controlling fluid loss! However, in practice, higher initial leakoff can yield greater overall fluid efficiency.

To confirm the controlling mechanisms, dynamic fluid-loss tests were conducted using a slot-flow geometry, determined to be the simplest representation of what occurs in a fracture. To completely describe the process, computer-controlled equipment was constructed to prepare and test fluids under dynamic conditions, subjecting them to the temperature and shear histories found in a fracture (see “Measuring Dynamic Fluid Loss in the Laboratory,” previous page). Cores of various lengths were used in the tests to simulate a fracture segment at a fixed distance from the wellbore.\(^10\) As the fracture tip passes a specific point, spurt occurs and the shear rate reaches a maximum (above). Then, as the fracture widens, the shear stress decreases. In the test apparatus, this is simulated by decreasing the flow rate with time.


\(^9\) Shear rate is proportional to shear stress, the exact relationship depending on the rheological model used for the fluid.

Pressure sensors along the core monitor the progress of the polymer front. Laboratory tests show that, for comparable fluids and rocks with permeabilities of up to 50 md, fluid loss is greater under dynamic conditions than static conditions (left). Further, examining the impact of shear stress and permeability on the magnitude of fluid loss and the effectiveness of leakoff-control additives in high-permeability formations led to five key conclusions.11

First, high shear rates can prevent the formation of an external filter cake and result in higher than expected spurt (below, left). Second, an internal filter cake controls fluid loss, especially near the fracture tip. Third, the effectiveness of fluid-loss additives increases with formation permeability and decreases with shear rate and fluid viscosity. Fourth, reducing fluid loss means reducing spurt, particularly under high shear conditions and in high-permeability formations. Finally, at high shear rates with no external filter cake, efficient spurt control must be achieved by plugging the pore throats at the surface of the rock.

The effect of shear depends on the type of fluid and the formation permeability. Typically, above a threshold shear level, no external filter cake is formed. The magnitude of fluid loss is dependent on the type of polymer and whether it is crosslinked. If the permeability is high enough and the fluid structure degrades with shear, polymer may be able to penetrate the rock matrix.

Dynamic tests revealed that commonly used additives were less effective in controlling fluid loss than static tests had previously indicated. Also, a direct link between fluid efficiency and shear rate was demonstrated. The higher the fraction of fluid lost under high shear early in the treatment, the higher the total leakoff volume and the lower the efficiency. Spurt has a dominant effect on efficiency and the volume of fluid pumped, particularly for the short pumping times encountered in fracturing high-permeability formations. If spurt is not controlled quickly and effectively during the high-shear period, fluid efficiencies drop dramatically.

These observations prompted researchers to develop a superior additive system that:
• controls spurt under high shear rates in high-permeability formations
• minimizes the influence of permeability on leakoff12
• limits the invasion of polymer into the matrix
• reduces the overall amount of polymer pumped into the fracture.
Evaluation of several additive types led to a combination of particulate materials, the HIGH SHEAR system, that achieves the above goals. One agent moves rapidly to the fracture face during the early stage of fluid loss when leakoff flux is high. This type of particle seals a major portion of the exposed surface quickly and adheres securely to the surface, resisting high shear forces. The second material plugs the remaining gaps in the developing filter cake as the shear rate drops, significantly reducing filtrate losses and sealing the surface so that polymer particles cannot penetrate the matrix. Laboratory tests show a 25 to 75% reduction in spurt compared to the best available products today (right). Fluid efficiency improves, meaning less fluid to pump, less fluid to break and easier cleanup. Since this process is aided by having a less viscous fluid—one that promotes high initial leakoff—there is a further opportunity for cost-savings and improved cleanup by reducing the polymer concentration in the fluid (page 46).

One concern with fluid-loss additives has been the possibility of their presence reducing proppant-pack conductivity. A key question is: Does the reduction in matrix damage brought about by additives outweigh the potential damage they may inflict within the fracture itself? As is well-known, the amount of conductivity damage is highly dependent on the type of fluid used. Flowback tests with different fluids and leakoff control additives confirm that particulate fluid-loss additives do limit matrix damage by minimizing fluid invasion. Conductivity tests show that these agents are actually less damaging to the proppant pack than previously thought. In most fracturing fluids, their impact on conductivity is minimal when used in low concentrations.

With these encouraging laboratory results, the next step was to test whether the HIGH SHEAR system could reduce treatment costs and improve well productivity better than conventional products. Extensive field trials in Canada show an overall 15 to 20% cost savings (see “Canadian Treatments Demonstrate Cost Savings and Productivity Gains,” next page). Productivity improvements averaged 460% compared to 260% on offset wells without the additive. Additional well tests are planned in areas such as the US Gulf Coast where a variety of fluids are used and larger-scale, high-permeability fracturing treatments are performed.

Understanding and Improving Fracture Conductivity

Simply creating a fracture does not guarantee better well performance. The fracture must provide a conductive flow path for formation fluids. For decades, poor treatment results were blamed on insufficient fracture length or inadequate proppant transport and placement. Studies in the late 1980s revealed that substantial fracture damage, and resulting impairment to flow, could be caused by polymer residue blocking the pore spaces between proppant particles.

Once the proppant pack is placed and pumping stops, fluid filtrate leaks off into the rock matrix and the pressure declines. The fluid remaining in the fracture must then be flowed back to allow production of hydrocarbons. Termed cleanup, this process is critical to the success of the treatment. One way to aid cleanup is to ensure that the polymer residue has been reduced to a minimum. A second is to use as little polymer as possible to start with. The next two sections look at recent developments in both areas.

Extending Breaker Technology

At the end of a treatment, the fluid left in the fracture has been partially dehydrated due to filtrate loss. The effective polymer concentration can be an order of magnitude higher than that originally pumped, reaching 300 to 600 lbm/1000 gal [36 to 72 g/cm³]. If the polymer stays intact, an ultrahigh viscosity, gelled mass results that blocks the pore space and cannot easily be flowed back into the well. To prevent this, the polymer is attacked by fluid breakers—oxidizers or enzymes that sever the polymer chain at its weakest points, degrading it into smaller, more mobile fragments. This reduces the viscosity of the residual fluid, thereby allowing more efficient cleanup. Breakers are used at reservoir temperatures below about 325°F [163°C]. If breaking is insufficient, concentrated polymer remains in the proppant pack, reducing the conductivity and treatment effectiveness.

Historically, active chemical breakers were dissolved in the fluid during surface mixing. As a result, the fluid was being attacked even as it was being pumped. Care had to be taken to use a sufficiently low breaker concentration. Otherwise, viscosity would decrease too quickly, and proppant would settle. With this low breaker concentration, only partial degradation of the polymer occurred. The result was impaired fracture conductivity.

Research during the past decade has found ways to increase breaking efficiency.

12. In high-permeability formations, permeability can vary widely. Using an average value in job design calculations can present execution problems during the treatment. An additive that dampens the effect of permeability variation can be beneficial.
14. In instances where the impact is significant, the damage can be countered by lowering the polymer concentration since fluids of lower viscosity can be used during the treatment.
16. Above this level, the fluid breaks with time due to the thermal degradation of the guar molecules.
More than 19 operational trials of the HIGHSHEAR fluid-loss control additive have been conducted in Alberta, Canada in clean sandstone reservoirs (right). Here, permeabilities vary from 50 to 150 md and porosities are 20 to 24%. Well depths typically range from 2300 to 2500 ft [700 to 760 m] with bottomhole temperatures of 85 to 95°F [30 to 35°C].

Earlier wells fractured in the field in 1993, as part of a refracturing program, yielded proppant placement efficiencies as low as 70%. Because of the relatively high permeability, its variability within the reservoir and high-concentration proppant schedules, an error of 10% in the fluid-loss design calculation could lead to 30% of the proppant not being placed. In addition to verification of laboratory test results with the additive, objectives for a new refracturing campaign were:

- reduced treatment cost
- improved job design and execution
- decreased volume of polymer pumped
- reduced well cleanup times
- increased production rates.

To achieve these goals, the strategy was to replace the 30 lbm/1000 gal borate-crosslinked fracturing fluid normally used with a reduced-polymer, 22 lbm/1000 gal system (page 46) to promote higher fracture conductivity, to speed cleanup (due to less damage from residual polymer) and to lower wellsite costs. With its inherently lower viscosity, the new fluid meant higher leakoff. To counteract this, the HIGHSHEAR additive was used to limit spurt, seal the fracture face and smooth out the effects of permeability variations.

Pad volumes of 2000 to 2500 gal [7.6 to 9.5 m³] were used with total slurry volumes of 4000 to 6000 gal [15.1 to 22.7 m³] in four stages. Typical rates were 15.7 bbl/min [2.5 m³/min]. Maximum sand concentrations ranged from 16.5 to more than 18.5 ppa.

The field trials were highly successful. Test wells showed consistent proppant placements of 95 to 100%. Over time, as experience with the system grew, pad volumes were maintained and...
higher sand concentrations were achieved as a result of increasing placement success. Less fluid pumped meant less fluid to break. Cleanup times were slashed from several days to one or two days. Post-treatment production increased from 260% in the 1993 campaign to 460% (previous page, middle). Overall treatment costs were 15 to 20% lower.

The changeover to the lower polymer loading was successful due to the fluid-loss additive. In separate trials without the material present, proppant placement efficiency was erratic.

According to Gilbert Dumont, production engineer for Petro-Canada Resources, “Fluids are coming back crystal-clear with this system, something we haven’t seen before. The wells are cleaning up quicker, in one to two days rather than three to ten days. This indicates we are getting faster and more complete breaking of the system. We believe our conductivities are higher as supported by increased well productivity.”

Michael Priaro, engineering consultant for Petro-Canada Resources adds, “Our success rate is greater because of more consistent placement. We’ve been able to obtain higher proppant concentrations with cleaner fluid. The cleanup has been better and quicker and well productivity after stimulation is definitely higher, averaging 4.6-fold improvement, with some wells showing almost 7-fold improvement. Ten-fold production improvements may be possible with further advances in treatment design.”

From Neal Wasylycia, production engineer for Petro-Canada Resources, “Comparisons of results are difficult with slant, deviated and directional wells with varied pays being fractured. We definitely know that our results on vertical wells are dramatically better, and 100% fracture placement can be repeated with confidence. Our overall refracturing costs are reduced due to lower fluid cost, quicker cleanup and reduced fluid disposal cost. The successful placement of fractures in deviated and slant wells represents our next challenge, as this is where our next large refracturing opportunity exists.”

By encapsulating breakers so they do not interact with the fluid until released by rupture of the protective coating with time or stress, higher concentrations can be used, degrading more of the polymer. This has been a major innovation for improving cleanup and proppant-pack conductivity and is a common industry practice today.17

The mechanisms of proppant-pack damage have been the subject of much study and much controversy. Recent findings have led to a more consistent and reproducible approach to testing proppant-pack damage. By understanding the controlling processes, scientists have been able to develop new-generation additives to improve fluid cleanup and fracture conductivity.

A keystone of the investigation was developing a relationship between retained permeability and porosity reduction in proppant packs. A graph of this correlation shows that, for example, a 10% change in porosity (from 30 to 27%) can reduce permeability by 35%. Laboratory tests verify the theoretical relationship (above, right). Small, random blockages by residual polymer or a thin, concentrated polymer filter cake at the fracture face lead to large reductions in retained permeability (below).

Another part of the study involved identifying the parameters and test procedures with the most significant effects on measured conductivity. Tests were performed at the Dowell laboratory in Tulsa, Oklahoma, USA and two independent laboratories. The

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results confirm that polymer concentration, for example, is critical. Its influence is nonlinear (below).

The relationships of other parameters to test results and reproducibility were also quantified, leading to a refined testing procedure. Testing by these laboratories using the new guidelines demonstrates that reliable results can be achieved, provided test conditions are closely controlled. Testing within the same laboratory is expected to vary by 15 to 20% while lab-to-lab variations have a 25 to 30% relative deviation (right). Before uniform procedures, test results often deviated by 100% or more.

The thorough investigation of conductivity testing provided a road map of how to improve breaker effectiveness. The problem was attacked on two fronts: selection of an optimal breaker for a given temperature range and development of an additive to assist in removal of the degraded polymer.

Each type and composition of breaker are effective over a certain limited temperature range, based on performance and cost criteria. This requires tailoring of chemical properties and encapsulation technology so that the breaker remains active in the proppant pack long enough to do its job. A suite of materials is needed to cover the range of temperatures that are encountered in fracturing operations.

But a breaker by itself is often not enough. Conductivity testing shows that residual fragments left after the primary polymer structure has been degraded can still cause significant pore blockage (below). Worse, under certain conditions, the fragments can coagulate—or bind together into a viscous mass—and reduce conductivity further. Sometimes, adding more breaker can aggravate coagulation.

To avoid this, a special blend of anticoagulants was developed. This blend, the CleanFLOW additive, works synergistically with the breaker to reduce the size of the polymer fragments and prevent their tendency to coagulate. The dispersive action of the additive increases mobility and available flow paths. Pore blockage is reduced and proppant-pack permeability increases.

Laboratory testing in standard conductivity cells shows that the breaker plus additive system outperforms breaker alone, yielding almost 40% higher proppant-pack permeabilities at low-end additive concentrations (next page, top). Retained permeabilities improve to as much as 90% at increased concentrations.

In field testing, treatments with the CleanFLOW additive showed higher levels of polymer returns during flowback than previous treatments on offset wells. Higher returns are a direct measure of improved proppant-pack cleanup. Over a given flowback period in a well in western Wyoming, USA, 62% of the polymer was returned when the additive was used with breaker, compared to 31% for an offset well with the breaker alone. At the end of the test phase, the well treated with the CleanFLOW additive was still returning polymer, while the offset well was not (next page, bottom).

Net present value (NPV) calculations on various formation types show that conductivity-related production increases realized from the use of the additive can significantly improve well economics.
Reducing Polymer Concentration

Today, over 70% of the fracturing treatments conducted use guar- or hydroxypropyl guar-based fluids. The rheology of such fluids has been studied for years. When added to water, guar molecules hydrate and swell, increasing in diameter and length. The hydrated strands overlap and hinder motion, giving rise to an increased viscosity of the solution. For adequate proppant transport and placement, a viscosity of 100 centipoise (cp) at a shear rate of 100 sec\(^{-1}\) is generally accepted as a minimum guideline.

To minimize fluid leakoff and counteract the inherent thinning of guar systems at elevated temperatures, however, higher viscosities have historically been used. In non-crosslinked (linear) systems, this means adding more polymer, resulting in polymer concentrations of 40 lbm/1000 gal \([4.8 \text{ g/cm}^3]\) or higher. This approach is expensive and often results in fluid mixing and handling difficulties. Fracture conductivity can be impaired, since more polymer must be broken and produced back. Crosslinking has become a common means of enhancing viscosity at lower polymer levels. While effective in building viscosity, this practice can lead to complicated, hard-to-break structures. Using crosslinkers, polymer levels can be reduced to about 25 lbm/1000 gal \([3 \text{ g/cm}^3]\). The goal of recent research has been to formulate a reliable fluid using even less polymer to reduce cost and improve fracture conductivity.

Various metal ions, including titanium and zirconium, have been used for decades as crosslinking agents. In recent years, boron \([\text{as B(OH)}_4^-]\) has grown in popularity and is by far the most common element today. Various boron salts and compounds

can be used (below). If the pH\textsuperscript{19} of the fluid is above 8, crosslinking occurs almost instantaneously when borate ions are added to hydrated guar (right). A unique feature of the resulting fluid is that the crosslinking is reversible. As temperature increases, the pH falls and the solution thins because there is less borate ion available in solution. Viscosity recovers as temperature decreases and the pH rises.

If crosslinking is too rapid, high friction pressure in wellbore tubulars and shear thinning may occur during pumping. This may not be a severe problem in shallow, low-temperature wells where pumping times are short, but is of major concern for deep, higher temperature treatments requiring extended pumping times. For these applications, it is necessary to delay the crosslinking process until the fluid has traveled through most, or all, of the well tubulars. This can be accomplished by varying the chemistry and additives in the fluid or by encapsulating the crosslinker, which permits time-released release of the active material. Delayed crosslinking reduces friction pressure and horsepower requirements and provides for higher injection rates.

For a stable and reliable borate crosslinked fluid to be prepared at a given temperature, sufficient polymer chains must be present for entanglement to occur. For most guars, solutions containing less than 20 lbm/1000 gal cannot effectively be crosslinked. In addition to having sufficient polymer in solution, two other criteria must be satisfied: the chains need to have enough active crosslink sites and the proper number of borate ions must be present to build a network structure. Careful balance between the two has to be maintained to produce a stable system.

In the past, borate crosslinked fluids at the lower threshold of 20 lbm/1000 gal guar concentration have been formulated in the laboratory and even tested in the field. Operational experience, however, showed them to be unreliable and overly sensitive to small variations in fluid chemistry.

How can the threshold polymer level necessary for crosslinking be reduced successfully? Based on earlier work with zirconate systems, scientists evaluated what types of materials associate with guar molecules to increase their solubility. After studying the behavior of a variety of materials, researchers identified a combination of chemicals that permits stable borate crosslinking at polymer concentrations as low as 15 lbm/1000 gal and reliable field formulations to be mixed in the 15- to 20 lbm/1000 gal range (next page, bottom).

These systems, referred to as low-guar fluids, can be used at fluid temperatures up to 175°F [80°C]. They exhibit viscosities normally measured for borate crosslinked fluids with polymer concentrations 5 to 10 lbm/1000 gal higher.

Proppant suspension properties are excellent, allowing use of proppant concentrations as high as 17 to 20 pounds of proppant added (ppa). The fluid can be continuously mixed and then crosslinked. It can be effectively degraded using available breaker sys-
tems for rapid, efficient cleanup following the treatment. Conductivity tests on proppant packs placed with low-guar fluids show 150 to 200% higher pack permeabilities than those obtained with conventional polymer concentrations (right).

Over 500 treatments have been pumped since the introduction of the fluid in 1994. Because of the success of these treatments, the low-guar system is rapidly becoming the fluid of choice for applications to 175°F.

Reduced polymer loading can lead to increased fluid leakoff. This can be prevented by the adding fluid-loss agents, particularly those obtained with the new HIGHSHEAR fluid-loss additive to improve conductivity, well cleanup and well performance. Low-guar systems, however, have shown that this may not always be necessary, depending on the type of formation and its permeability. In more than 130 jobs performed in Kansas, USA in 5- to 50-md formations, no fluid-loss additives were used. Fluid efficiency was not adversely affected, and conductive fractures were obtained. Cleanup times were reduced by 50% compared to previous treatments. Proppant placement efficiencies—the percentage of proppant effectively placed in the fracture—met or exceeded 97%.

In even higher-permeability formations, as tests in Alberta, Canada (page 42) conclusively demonstrate, low-guar systems can be used effectively with the new HIGHSHEAR fluid-loss additive to improve fracture conductivity, well cleanup and well performance.

## Controlling Proppant Flowback

Flow of proppant into the wellbore following a fracturing treatment is of major concern. This phenomenon may occur during initial cleanup or sometime after the well is put back on full production. Termed proppant flowback or proppant backproduction, it can lead to expensive, time-consuming remedial operations and safety concerns. In low-rate wells, proppant may settle in the casing, requiring periodic wellbore cleanouts. Loss of near-wellbore fracture conductivity can result, and production may cease entirely if the productive zone is fully covered. In high-rate wells, erosion occurs to tubulars, control valves and wellhead equipment. Disposal costs for produced proppant may be substantial.

The frequency of this problem has increased markedly as greater fracture widths and higher proppant concentrations have become the norm. In areas such as Alaska and the North Sea, up to 20% of the proppant may be produced back, while some instances of up to 50% have been reported. This can translate into anywhere from 1000 to 100,000 lbm (454 to 45,400 kg) of proppant per treatment. Although the flowback may stop with time, many wells produce proppant throughout their lifetimes. Wells often must be placed on restricted chokes to limit pressure drops and stabilize the proppant pack.

While changes in fracture design and execution can sometimes alleviate the problem, a typical solution has been the use of resin-coated proppant (RCP). RCPs are pumped into the fracture near the end of the treatment, referred to as tailing in. The well may

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<td>125</td>
<td>216</td>
<td>-</td>
</tr>
<tr>
<td>15 lbm</td>
<td>125</td>
<td>130</td>
<td>60</td>
</tr>
<tr>
<td>20 lbm</td>
<td>125</td>
<td>106</td>
<td>49</td>
</tr>
<tr>
<td>30 lbm</td>
<td>125</td>
<td>63</td>
<td>29</td>
</tr>
<tr>
<td>2% KCl</td>
<td>175</td>
<td>125</td>
<td>-</td>
</tr>
<tr>
<td>20 lbm</td>
<td>175</td>
<td>61</td>
<td>49</td>
</tr>
<tr>
<td>30 lbm</td>
<td>175</td>
<td>32</td>
<td>26</td>
</tr>
</tbody>
</table>

Proppant Type: Sand
Proppant Concentration: 2 lbm/gal

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19. The measure of acid intensity equal to the logarithm of the reciprocal of the hydrogen ion concentration of the solution. pH 7 is neutral; below 7 is acidic, above alkaline.


be shut in for a period of time to allow the resin to cure as its temperature rises, binding the proppant particles together at their points of contact. Ideally, a consolidated, high-conductivity matrix is formed.

RCPs, however, are not universally applicable and have certain severe limitations. Performance is sensitive to shear, temperature, closure pressure and shut-in time. Conductivities are frequently lower than expected. In low-temperature wells, an expensive activator must be added to the RCP at a 0.5 to 2.0% concentration for the resin to cure. Shut-in times may be as long as 24 hours. Resin coatings can interact chemically with fracturing fluid additives. Cyclic loadings, caused by the well being shut in and put back on production over time, can cause the pack to fail. In extreme cases, gelled masses of resins can be produced back.22

Because of these drawbacks, there is a major incentive to introduce a more consistent means of controlling proppant flowback that also improves well cleanup efficiency and maximizes well productivity.

Recent research has helped define the mechanisms underlying proppant-pack degradation and has led to the invention of a physical, rather than a chemical, solution to the problem. This innovation, called PropNET technology, uses fibers to hold the proppant in place. Pumped together with the proppant in the fracturing fluid, the material forms a web, or network, which stabilizes the proppant-fiber pack and allows high production rates of oil or gas (above). The technology is based on the principles of fiber reinforcement commonly used in a variety of industrial and commercial applications as a strengthening method. For example, natural and synthetic fibers are used to protect dams and other concrete and soil structures from erosion. The inherent ability of fibers to stabilize highly porous, particulate-containing materials provided a basis for these investigations.

A comprehensive set of tests has been applied to determine the applicability of fiber reinforcement and to characterize the properties and performance of fiber-containing packs. Conductivity test cells measured proppant-pack permeability. Special pack-mobility tests simulated conditions before, during and after well cleanup. Three configurations of test cells were developed and constructed to evaluate the key parameter—pack resistance to proppant flowback—as measured by the maximum flow rate that the pack can withstand or the maximum pressure drop across the pack before proppant is produced.

A variety of fiber types were investigated, including polymer, glass, ceramic, metal and carbon. Based on several evaluation criteria, a special, flexible glass fiber was chosen for its performance, cost and availability. The material has a 2.55 g/cm³ [21.3 lbm/gal] bulk density, similar to that of most proppants. Selection of the particular glass fiber was based on its stability to fluids and downhole conditions. Fibers must meet minimum size criteria to be effective. Short, small diameter fibers are less effective in strengthening the proppant pack. Glass fiber diameters of 10 to 20 microns and lengths of 10 mm or more provide optimum pack stability and ease of handling.

How the fibers work is open to debate, but it is thought that they interweave among the proppant particles, providing increased strength, or that they stabilize and distribute stress, aiding bridging, within a significant area of the pack. The fiber structure is more flexible than cured RCPs, allowing the proppant-fiber pack to shift without failing.

Laboratory tests show that the ability of the pack to resist proppant flowback is a function of fiber concentration. Stability increases with fiber content until a plateau is reached (below). While laboratory data show that use of 1.5% fibers by weight can reduce permeability by up to 30% compared to packs without fibers,23 field results show less reduction. Conductivity values for packs with fibers are superior to those measured for postcured RCPs.24

Despite the low concentration of 1.5%, the fiber level is about 30% by number of particulates, or about one fiber for every two proppant particles. Fiber length is an order of magnitude more than proppant diameter, so, for example with sand proppants, each fiber touches approximately five particles (next page, top).

Single-phase flow tests using water and two-phase tests with water and gas were conducted without a confining stress and with a stress of 1000 psi. Results show that pack stability increases with pack width to a certain limit and that packs with more spherical and uniform ceramic proppant are generally less stable than irregular grain sand packs. Packs can withstand pressure...
gradients in excess of 100 psi/ft, but typical levels are 45 psi/ft (right). Worst-case flow conditions (80%/20% gas-to-water ratio) were used to establish maximum flow-rate guidelines. Under these conditions, pack stability reaches a minimum at about 40% of the maximum pack strength in single-phase fluid flow. Based on laboratory data, maximum cleanup rates of 30 bbl/day/perforation [4.8 m³/day/perforation] for sand and 20 bbl/day/perforation [3.2 m³/day/perforation] for ceramic proppants are being used in the field.

Tests results show that no minimum confining stress, shut-in time or reservoir temperature are required for the fibers to be effective, overcoming some of the severest limitations of RCPs.

Packs were cycled under stress to simulate shut-in and production periods, with packs subjected to alternating stress levels of 1000 psi and 4000 psi. No pack failures were observed, even after more than 30 cycles, for both sand and ceramic proppant packs. Aging studies were also conducted, since glass fibers can be dissolved by formation waters. The solubility rate depends on several factors, including temperature, pH and the type of minerals present in the water (silica being the most important). Results show that fibers are expected to retain 50% of their effectiveness for at least two years at 300°F [149°C] when in contact with a silica-saturated formation brine. Life expectancy could be greater, depending on downhole conditions.

Glass fibers do not interact with common fracturing fluid systems or additives, a key concern with RCPs. Their presence in the fluid slurry also reduces proppant settling, aiding proppant transport and placement. Glass fibers have certain limitations to be considered during treatment design. They are not effective at temperatures above 300°F and under certain conditions: if for-

23. This observation is consistent with calculations in which fibers represent 5 to 6% of the pore volume.
Texas, USA:
A 10,000-ft [3080-m] gas well in south Texas, USA with a bottomhole temperature of 275°F [135°C] was fractured using a borate-crosslinked fluid. A fiber-reinforced pack was placed with 1.5% fiber by weight of proppant. Fibers were added during the entire proppant stage. Pumping pressure levels were similar to treatments without fibers present. Of the nearly 16,000 lbm [7300 kg] of proppant placed, less than 0.07% was produced back. The well was later cycled through four shut-in and production periods, with a shut-in closure stress of 1900 psi and a flowing tubing pressure of 4200 psi. Production was essentially proppant free and remains so today well over a year later. Productivity from the well exceeded that from offsets.

In another south Texas gas well, having two sandstone layers separated by a shale layer, 226,000 lbm [102,500 kg] of proppant were placed using a borate-crosslinked guar fluid. Here, fibers were tailed in with the last 15% of the proppant. Flowback started as soon as the treatment was completed. The initial flowback rate of 500 bbl/day [80 m³/day] was increased to 1000 bbl/day [160 m³/day]. Less than 0.05% of the proppant was produced back over a four-day period.

How fiber reinforcement compares with RCPs was evaluated in an offset well. An upper productive zone was fractured with a 15% fiber tail-in treatment, while a lower zone used a 23% RCP tail-in. The PropNET zone had a much higher initial flowback rate, earlier gas breakthrough and more rapid fluid returns (middle). Cleanup costs were reduced and fracturing fluid recovery was maximized, allowing the well to be placed on production sooner (bottom). Conductivities were higher with PropNET treatments than for RCPs.
According to Gary Slusher, project production engineer for Enron Oil & Gas, in Corpus Christi, Texas, “We have had to live with RCPs. They can be effective, but they are expensive and require long cure times, and once you start pumping them you’re committed. When we bring a well back, we have to do it gingerly to avoid problems. With PropNET, we can start and stop pumping as necessary and aggressively flow back the wells. The system is more effective in stopping proppant production than RCPs.

“We’ve seen both direct and indirect benefits with PropNET. We’re getting much higher fluid recoveries and more rapid cleanup. This reduces our total job costs substantially, by 12 to 15% or more. We believe our effective frac lengths are longer, too. But, most importantly, we get the gas to market sooner by turning the wells around faster, sometimes in about 24 hours instead of seven to ten days. We’ve also been able to use simpler fluids with less additives. That’s saving us additional money and reducing friction pressures and horsepower requirements. When the job has been executed according to design and the material has been placed where it’s needed, the results have been excellent.”

Indiana, USA:
In low-temperature gas wells in Indiana, USA, RCPs are commonly used when fracturing multiple zones. This requires an activator and an extended shut-in period for curing of each zone after treatment, or a total time of four to five days per well. When fiber technology was used instead, the initial zone could be flowed back only 10 min after the job was completed. Following a limited flowback period, the next zone could be fractured immediately, completing operations in one day, a 75 to 80% savings in rig labor, rig time and equipment costs.

New Solutions with Novel Technology
The impressive developments in fracturing fluids technology from 1985 to 1993 have been reinforced by innovations during the past two years. Advanced fluid-loss additives are improving fluid efficiency at lower fluid viscosities. Combined with new low-guar systems, this means reduced costs and reduced damage to the fracture. Enhanced breaker and additive systems are speeding well cleanup, giving more complete fluid degradation and cleaner, more conductive fractures. And, the fracture is now more stable, thanks to innovations in proppant flowback control.

Individually and collectively, these new technologies are benefitting oil and gas operators by reducing treatment and well cleanup costs, increasing well productivity and speeding product sales to market. In the future, the increased emphasis on more efficient and effective fluids and the synergistic application of low-cost innovations will yield further economic gains. —DEO

25. Fibers are resistant to hydrochloric acid [HCl], the acid commonly used, but not to hydrofluoric acid [HF] which is known to dissolve glass.