Fracture stimulation treatments often fail to achieve predicted results because design data have not accounted for the downhole environment. Since 1986, the Dowell Schlumberger fracture conductivity laboratory has been carrying out realistic evaluations of proppants, fracturing fluids and additives. One element of this program has shown that viscous components of the treatment fluid remain in the proppant and significantly block flow of oil and gas. This knowledge has been applied to develop a new way of breaking down flow resistance, taking the brakes off proppant-pack conductivity.

Every stimulation treatment is designed to improve the flow of hydrocarbons from reservoir to wellbore. Hydraulic fracturing is one of the most common ways of achieving this. Since the first recorded hydraulic fracture in 1947, over one million treatments have been executed. About 40 percent of today's wells are hydraulically fractured, and this process has made 25 to 30 percent of US oil reserves economically producible.

In an unstimulated well, reservoir fluids converge radially on the wellbore. When hydraulic fracturing is undertaken, well productivity is increased by pumping fluids into the formation at sufficient rates and pressures to hydraulically open and extend a fracture deep into the reservoir. Reservoir fluid flow then becomes linear towards the conductive fracture that intersects the wellbore (right).

Fracturing stimulation starts with pumping of a gelled fluid—the pad—which initiates and propagates the fracture. This is followed by a slurry of the gelled fluid mixed with particulate material—proppant. When pumping stops, the proppant prevents the fracture from closing, thereby maintaining a conductive path deep into the formation—typically 200 to 2000 feet (60 to 600 meters) from the wellbore (next page).

The determinants of fracture conductivity are fracture width and the permeability of the proppant pack. Following a successful treatment, this permeability is orders of magnitude greater than that of the surrounding formation.

When designing fracturing fluid, viscosity is a prime consideration. It needs to be high enough to create a fracture and transport proppant at rates up to 12 lbm/gal for several
hours at high temperature. Fluid loss into the formation also needs to be controlled, usually through buildup of a filter cake. For these reasons, polymeric gelling agents are commonly used in the fracturing fluid. If downhole conditions, like temperature and pumping time/rate, are especially harsh, these normally linear polymers can be crosslinked using chemical additives. This improves the fluid’s stability and viscosity. Ideally, high-viscosity fluids can be designed to revert to low-viscosity solutions after the treatment to allow the fracture to clean up easily. Gels are degraded—though rarely completely—either by the temperature of the reservoir or by “breakers,” chemical agents added to the fluid that break up the polymer molecules.

While fracturing clearly offers operators major benefits, many treatments do not achieve the results that prejob simulations predict. Production testing after the treatment often gives a lower than expected “apparent” fracture conductivity. A number of reasons can explain this shortfall including inappropriate testing and analysis, non-Darcy flow effects and well completion restrictions. But a key cause is an actual reduction in the proppant-pack conductivity.

At first, work centered on failure of the proppant placed in the fracture. The performance of proppant can decline rapidly through exposure to high formation temperature and stress as the fracture closes (see “Proppant Properties,” next page). But even this failed to fully describe the shortfall in fracture conductivity. Attention then turned to examining other potential sources of damage to proppant-pack conductivity. In 1986, the Dowell Schlumberger (DS) research facility in Tulsa, Oklahoma, USA began to develop a state-of-the-art fracture conductivity laboratory. Equipment has been designed and procedures developed to

Taking the Brakes Off Proppant-Pack Conductivity

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Proppant Properties

Properties of propping agents that influence fracture conductivity include strength, particle size, particle size distribution and proppant quality—factors like the amount of fines and impurities, grain shape and density.

Proppant strength describes resistance of the particles to crushing during fracture closure. This is primarily due to rearrangement and packing of the proppant as it is crushed (right). Long-term proppant-pack permeability is significantly reduced when proppant is exposed to elevated temperature and stress. In addition, fines and small particles generated by proppant crushing invade and plug the proppant pack, further reducing fracture permeability.

Proppant particle size has a significant effect on fracture permeability. Large particles provide greater permeability at low stress levels. However, grain strength decreases as proppant size increases. This results in a much steeper permeability decline with increasing closure stress for large proppant than for small materials. Large diameter proppants can also be difficult to place in the fracture, because a wider hydraulic fracture opening is required and the settling rate of particles increases with increasing size.

Particle size distribution and proppant quality are closely related. A high percentage of smaller grains or impurities can have the same effect on fracture permeability as invading formation fines. Proppant quality is not as important in shallow wells with low closure stresses, but becomes increasingly important with increasing closure stress.

Shape of proppant particles can also have a significant effect on fracture permeability. The rounder the grain, the fewer corners and edges there are to break off and form fines. Stresses on the proppant grains are more evenly distributed when the grains are spherical and of similar size, allowing them to resist a higher load before failure occurs. Particle roundness and sphericity are evaluated using a visual test.

Under some conditions, proppant density can be important. High-density materials are more difficult to suspend and transport in the fracture. Their placement can be achieved by increasing flow velocity, but this leads to higher pressures in the fracture and can result in excessive height growth. Placement may also be achieved by using higher viscosity fluids, which, at lower pump rates, can carry the proppant the length of the fracture with only minimal settling.


reproduce the in-situ environment and evaluate interactions between reservoir, proppant and fracturing fluids (see "Stimulation Simulation in the Laboratory," page 24). The laboratory can simulate such physical conditions as dynamic fluid loss, which occurs during the pumping treatment; fracture closure and volume reduction that occur when the pumping stops; and the post-treatment fracture environment to which the proppant pack is exposed during shut-in and flowback. Work at the laboratory has focused on characterization of proppant-pack permeability damage caused by fracturing fluids and studying ways to reduce the damage.

A key parameter in these studies is the post-closure concentration of polymer. Experiments show that as a fracture closes, base fluid is lost into the formation and polymer molecules, too large to penetrate the pore throats, remain in the proppant pack which undergoes a four- to ten-fold increase in polymer concentration depending on final fracture width (below). As the base fluid leaks off, the post-closure fracture polymer concentration factor (FPC) can be calculated by assuming that all the polymer from the fluid remains in the proppant pack.  

![Fracture open and closed diagram](image)

Predicting post-closure polymer concentration. In this plot for 20/40 Northern White sand, a 50,000-gal treatment with a gel concentration of 40 lbm/1,000 gal deposited 150,000 lb of the proppant. The average proppant concentration is 3.0 lbm/1,000 gal. For a proppant-pack porosity of 33.5% (middle curve), the post-closure polymer concentration factor is approximately 15. Polymer concentration within the proppant pack after closure would therefore average 15 times the initial polymer concentration—600 lbm/1,000 gal.

Multiplying FPC by the initial polymer concentration gives the final polymer concentration in the propped fracture (above).

Polymers within the proppant pack having initial concentrations of 30 to 60 lbm/1,000 gal, may reach concentrations of 300 to 1000 lbm/1,000 gal on fracture closure. Polymer concentrations of this magnitude are difficult to displace. They are not fully degraded by the amount of breaker conventionally employed and remain in the proppant pack, causing significant damage to permeability.

The long-term impairment of proppant-pack permeability caused by several commercial fracturing fluids has been quantified for bottomhole static temperatures of 100°F to 200°F [38° to 93°C]. DS conducted a baseline study using linear gels based on guar (a carbohydrate polymer refined from seeds) and hydroxypropyl guar (HPG). This defined the effects of polymer type and polymer concentration in the propped fracture.

Polymer gel concentration in the proppant pack. When pumping stops and the fracture closes, much of the fluid in the fracture is lost to the formation. However, because polymer molecules are large, they remain in the fracture, increase in concentration and significantly reduce proppant-pack conductivity.

3. \[ F_{PC} = \left( \frac{C_p}{C_s} \right) \left( \frac{\phi}{100} \right) \] in which:

- \( F_{PC} \) is dimensionless polymer concentration factor,
- \( C_p \) is proppant concentration in fluid and \( \phi \) is proppant-pack porosity.
centrations on the retained proppant-pack permeability. The tests were carried out at 160°F (71°C), well below the temperature at which effective thermal degradation of the polymer is believed to occur.

Guar and HPG both caused significant and essentially equivalent damage at elevated polymer concentrations. When guar or HPG fracturing fluids were concentrated in the proppant pack to 240 lbm/1,000 gal, permeability was reduced to 24 percent of the undamaged value, and to 14 percent and 13 percent respectively when the polymer concentrations were increased to 400 lbm/1,000 gal.

This was a surprise. In the past, the reduction of fracture permeability had been attributed to insoluble contaminants in the polymers. Guar is typically reported to contain two to three times as much insoluble material as HPG—7 to 10 percent by weight versus 2 to 4 percent—and would therefore be expected to cause considerably greater permeability impairment. Since essentially no difference was observed between the permeability damage attributable to concentrated guar and HPG fluids, it appears that proppant-pack permeability is much more sensitive to polymer concentration than to insoluble residue content. This conclusion is significant as it supports the use of the cheaper natural guar as opposed to derivatives such as HPG.

Looking beyond linear gels, a study was then performed to define the concentration effects of crosslinked guar and HPG fluids. Two systems were evaluated with different crosslinkers—borate at pH 9.5 and titinate (IV) at pH 4. Both crosslinked fluids impaired proppant-pack permeability significantly more than linear gels (below, left). Fluids crosslinked with a titinate were more damaging than those crosslinked with borates.

These results underline the need for efficient degradation of the gel to reduce its viscosity and improve well cleanup—which is where breakers come in. Amine catalyzed persulfate or enzyme breakers are usually employed at less than 125°F (52°C) while oxidizing chemicals handle the mid-range up to 225°F (107°C). At high temperatures, thermal degradation has been thought to be sufficient and breakers unnecessary.

However, during fracture closure, soluble breakers are lost into the formation along with the nonpolymeric components of the treatment fluid. Therefore, breaker concentration, designed to reduce the viscosity of the original fracturing fluid without allowing for leakoff, are not enough. Permeability damage caused by concentrated guar and HPG fracturing fluids can be reduced only by substantially increasing breaker concentration.

In its research program, DS next determined the effects on proppant-pack permeability of linear and crosslinked fluids treated with varying concentrations of the oxidative breaker ammonium persulfate (APS) [(NH₄)₂S₂O₈]. This work showed that, up to a limit, increasing breaker concentration significantly reduced permeability impairment (below, right). (See "Effect of Breaker Concentration on Proppant Permeability," next page, below).

The rate at which APS acts is a function of both concentration and temperature. Above 140°F (60°C), APS is extremely active and the quantity required to degrade the concentrated amount of polymer in the proppant breaks the fracturing fluid before it reaches the formation. At 160°F, as little as 1 lbm/1,000 gal of APS will degrade fracturing fluid viscosity to below proppant-carrying levels in less than an hour. But 6 lbm/1,000 gal of APS is needed to significantly degrade the concentrated polymer and improve the retained permeability. Such elevated breaker concentrations could be tolerated for only a few minutes.
added in high concentrations without premature loss of fracturing fluid viscosity (left). Unlike conventional breakers which dissolve in the fracturing fluid, the encapsulated breaker cannot leak off and be lost to the formation. Instead, it remains in the fracture, just where it is needed for degradation of the concentrated polymer.

Once the fracturing treatment is over, the encapsulated APS must be released. Several potential release mechanisms were considered. Chemical triggering—based, for example on pH, chelation or reduction/oxidation reactions—would have to tolerate wide variations in the treating and well fluid compositions; reliability and consistent performance would be hard to achieve. Time- or temperature-dependent release mechanisms—like breaker solubility, coating dissolution or decomposition—would again be difficult to control. It would be hard to devise a system with zero initial release and no effect on other fluid properties that operates over broad temperature and time ranges.

However, this has largely been achieved by releasing the breaker from the capsule in two ways. After completion of the fracture treatment, the hydraulic pressure dissipates and the fracture closes on the proppant and encapsulated breaker, causing high point-to-point stresses. These cause faults in the breaker coating which allow water to penetrate and solubilize the APS which is then released to the concentrated polymer within the fracture. Additionally, even with barrier coatings highly resistant to water, some permeability to water occurs. Water will eventually penetrate the coating of unruptured particles and release the APS.

To achieve a reasonable degree of breaker release through fracture closure, the encapsulated breaker must be larger than the pore size of the proppant pack. It must also be small enough to be transported within the fracture without suffering serious mechanical damage. Furthermore, to limit breaker release during placement, a small surface area to volume ratio—and therefore large particles—is favored, but to maximize distribution of APS a large number of particles—and therefore small particles—is favored. A breaker size roughly the same, or slightly larger, than that of the proppant balances all these factors.

The material coating the capsule has to be resistant to the fracturing fluid yet amenable to release by uniaxial stress. It must also be inert to the strongly oxidizing properties of the APS core. After investigation, DS selected an aqueous polyvinylidene chloride copolymer (PVDC CP)-based latex. The method of coating the breaker is important to its downhole performance. The coating

Effect of Breaker Concentration on Proppant Permeability

<table>
<thead>
<tr>
<th>APS Breaker (lbm/1000 gal)</th>
<th>% of Original Permeability</th>
<th>Linear Gel</th>
<th>Borate Crosslinked</th>
<th>Tannate Crosslinked</th>
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<tr>
<td>1 lb</td>
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<td>60</td>
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</table>


Stimulation Simulation in the Laboratory

Downhole conditions during fracturing treatment can be difficult to model in the laboratory, requiring simulation of dynamic fluid loss, static fluid loss, and concentration of gel polymer as the fracture closes. The post-treatment environment of stress, temperature and fluid flow also must be reproduced reliably. And to perform tests that are repeatable, physical parameters—like additive concentrations, pumping rates and pressures—have to be accurately controlled.

The standard laboratory evaluation of proppant performance under in-situ reservoir conditions is performed using a linear flow cell apparatus and procedures adapted by the American Petroleum Institute (API). Proppant is loaded into the cell, where stress can be directly applied by placing the cell in a hydraulic press and forcing the cell’s upper piston downward onto the confined proppant pack. The pressure drop is observed when a liquid or gas is pumped at constant rate through the confined proppant pack. Permeability may then be calculated using Darcy’s law.

Such tests can be performed relatively quickly, a permeability-versus-stress curve for a given proppant being generated in a day. The results are usually combined with fracture-fluid characterization—rheology and residue content analysis—to design fracture treatments. However, the standard API cell cannot simulate leakoff, and therefore does not account for damaging effects of fracturing fluids.

In a first redesign of the test cell, a flat core of rock 10 square inches (65 cm²) is sandwiched between the base of the cell and the proppant pack (next page, left). The slab is machined to fit exactly in the cell and then sealed with a silicon gasket so that fluid cannot bypass the rock.

After proppant has been placed evenly on top of the core, it is saturated with 2-percent potassium chloride solution to ensure that no air is entrained. Then, fracturing fluid is poured on top of the proppant pack and gradually squeezed through it, as the piston is forced down onto the proppant pack. Any fluid that percolates the rock is channeled through three fluid leakoff ports. Permeability is assessed similarly to the method employed for the API cell.

A more sophisticated device, called a dual-core fracture conductivity test cell (next page, right), adds a second core above the pack to more realistically simulate a fracture by allowing for fluid loss and proppant embedment on the two cores. Studies using the dual-core conductivity cell are typically divided into four stages: dynamic fluid loss, static fluid loss, shut-in and fluid flowback. Each stage simulates part of the fracturing treatment and affects final fracture permeability.

Dynamic fluid loss involves the establishment of a filter cake on the cores prior to injection of a fracture fluid/proppant slurry at known concentration. Fracturing fluid is first preconditioned by pumping through a heated high-shear flow loop to simulate flow down tubing strings. Then, for 90 minutes, it is pumped through the dual-core cell which can be heated. As the pressurized fluid passes through the cell, it leaks off through the rock, forming a filter cake. Computer monitoring of fluid loss through the core allows characterization of the wall-building properties of the fracturing fluid.

A fracturing fluid/proppant slurry is then flowed into the test cell and confined as the final stage of dynamic fluid loss. Closure pressure is applied to the quiescent proppant pack to begin the simulation of fracture closure. This marks the beginning of the static fluid loss stage.

However, if the prime function of the test is to understand the relationship between proppant permeability and polymer concentration, the dynamic test introduces an important unknown factor. The polymer concentration in dynamically deposited filter cakes is unknown. This
makes the post-closure polymer concentration in the cell a variable. Therefore, when seeking to establish the amount of breaker required as a function of polymer concentration after closure, DS researchers prefer to obtain fracture conductivity values through static fluid loss measurements alone.

In the static fluid loss stage, proppant and fracturing fluid are loaded into the preheated cell. Temperature and closure stress are rigidly controlled and monitored by computer. An initial closure stress of 500 psi creates static fluid loss through the cores to collection vessels, and concentrates gel polymer within the simulated fracture. When the simulated fracture has closed on the pack, closure stress is increased until a final predetermined value is reached.

The shut-in stage allows for drawdown and compaction of the proppant. The test cell is usually shut in for about 17 hours at final closure stress and temperature following static fluid loss.

In the fluid flowback stage, proppant-pack cleanup begins by flowing a heated brine solution—2 percent by weight potassium chloride—through the proppant pack at 3 cc/min (equivalent to 8 bbl/hr cross-sectional area at the wellbore per day). Brine can be followed by diesel or nitrogen gas flow. Pressure measurements are taken across the flow path and permeabilities are calculated. The test ends when steady-state permeabilities are maintained.

January 1991
technique has to take into consideration that PVDC CP-based latex is water-based and APS is water soluble. After trials the Wurster coating process was chosen to encapsulate the breaker (right).

Encapsulation of the breaker allows use of the much higher concentrations of breaker required to deal with the concentrated gel in the proppant pack. In a borate-crosslinked gel at 160°F, for instance, encapsulated breaker can be added at 2 lbm/1,000 gal with minimal viscosity loss in one hour, or at twice that concentration with about 65 percent loss (below). Even 8 lbm/1,000 gal produces less viscosity reduction than 0.5 lbm/1,000 gal of APS dissolved in the fluid.

Since late 1989, more than 100 fracturing treatments using the E-B-Clean encapsulated breaker system have been successfully carried out. Few operational changes have been required. POD® Blenders, which mix the proppant with the gelled fluid, have been modified to handle the new breaker—an auger-type solid metering unit has been installed. The blenders are also equipped to deliver liquid APS.

With accurate metering available, jobs are being designed that incorporate both encapsulated breaker and liquid APS. Fluid to be pumped early in the treatment employs only encapsulated breaker. Then, as the job progresses, APS is gradually phased in to replace encapsulated breaker for fluid that will spend less time at reservoir temperatures. This way, the cost/benefit of the fracturing treatment is optimized, while full cleanup of the fracture is ensured.

The majority of fracturing treatments performed to date using encapsulated breaker have been in Texas, USA—particularly the 5-md Canyon Sand in West Texas. Recently, jobs have been performed on high-permeability oil zones (50 md) in Alaska, USA and in a low permeability North Sea gas well.

For example, five wells treated with the DS CleanFRAC™ service—which incorporated EB-Clean encapsulated breaker at 4.8 lbm/1,000 gal—an averaged 219 percent higher initial production than 12 wells treated with conventional breaker at 1 lbm/1,000 gal (production was normalized to account for different porosities). After 60 days, cumulative production from the wells treated with EB-Clean encapsulated breaker

![Graph showing optimized production](image)

<table>
<thead>
<tr>
<th>Time, days</th>
<th>Cumulative production, million SCF/ft²</th>
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<tbody>
<tr>
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<td>2</td>
</tr>
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<td>20</td>
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<tr>
<td>50</td>
<td>40</td>
</tr>
<tr>
<td>60</td>
<td>80</td>
</tr>
</tbody>
</table>

Normalized cumulative production of 12 wells using 1 lbm/1,000 gal of conventional dissolved breaker compared with five wells stimulated using an optimized breaker design that included encapsulated breaker at 4 lbm/1,000 gal.

† Mark of Dowell Schlumberger

![Graph showing viscosity loss](image)

- Effect of encapsulated breaker on fracture fluid viscosity. Breaker dissolved in the fracture fluid rapidly degrades viscosity; encapsulation delays this unwanted effect. Addition of as much as 8 lbm/1,000 gal of encapsulated breaker shows less reduction in fracture fluid viscosity than 0.5 lbm/1,000 gal of conventional APS.

- A Wurster coating chamber for encapsulating breaker. A bead of core material (APS) is fluidized by a column of heated air drawn into the chamber from below the air distribution plate. The pattern and size of the holes in the plate result in most of the air passing through the center of the chamber, pulling breaker particles through the coating partition.

- On leaving the partition, the airborne particles enter an expansion chamber. The air loses velocity and the particles fall down the outside the partition. A venturi effect now comes into play, pushing the air horizontally toward the center, causing the droplets to be drawn into the upward column of air and recirculated.

- As the particles cycle through the partition, a polymeric coating is applied by a spray nozzle mounted below the partition. After many passes, the desired thickness of coating is achieved. The incoming heated air dries the sprayed particles after each trip through the spray area.

- The enclosed graph shows the percent of original viscosity impaired. It indicates that encapsulation significantly reduces the viscosity loss of the fracture fluid.

- The dashed line represents the scenario without encapsulation, while the solid lines represent the viscosity loss with encapsulation at different concentrations.