

Elements of Hydraulic Fracturing

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Editor

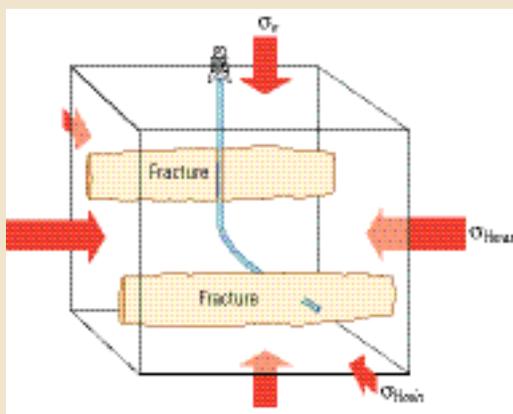
A well's ability to produce hydrocarbons or receive injection fluids is limited by the reservoir's natural permeability and near-wellbore changes resulting from drilling or other operations. *Hydraulic fracturing*, also known as *hydraulic stimulation*, improves hydrocarbon flow by creating fractures in the formation that connect the reservoir and wellbore.

A *hydraulic fracture* is a pressure-induced fracture caused by injecting fluid into a target rock formation. Fluid is pumped into the formation at pressures that exceed the *fracture pressure*—the pressure at which rocks break. To access a zone for stimulation, engineers perforate the casing across the interval and use retrievable plugs to isolate the interval from other open zones. This interval is then pressurized to the *formation breakdown pressure*, or *fracture initiation pressure*, the point at which the rock breaks and a fracture is created.

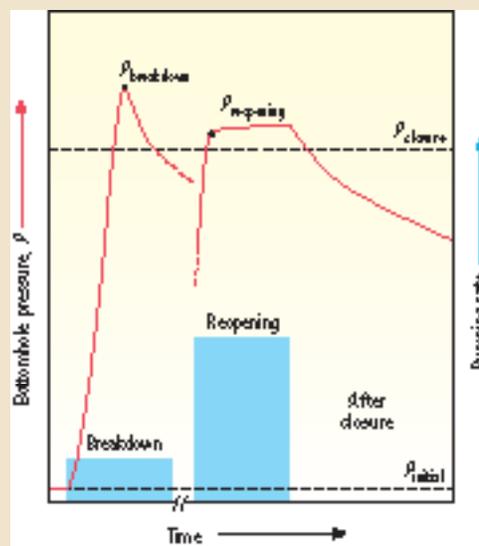
The Physics of Fracturing

The size and orientation of a fracture, and the magnitude of the pressure needed to create it, are dictated by the formation's *in situ stress field*. This stress field may be defined by three principal compressive stresses, which are oriented perpendicular to each other (below). The magnitudes and orientations of these three principal stresses are determined by the tectonic regime in the region and by depth, pore pressure and rock properties, which determine how stress is transmitted and distributed among formations.

In situ stresses control the orientation and propagation direction of hydraulic fractures. Hydraulic fractures are tensile fractures, and they open in the direction of least resistance. If the maximum principal com-



^ In situ stresses and hydraulic fracture propagation. The three principal compressive stresses (red arrows) are a vertical stress (σ_v) and a maximum and minimum horizontal stress (σ_{Hmax} and σ_{Hmin}). Hydraulic fractures open in the direction of the least principal stress and propagate in the plane of the greatest and intermediate stresses.



^ Fracture pressures. During a stimulation treatment, engineers pump fluid into the targeted stimulation zone at a prescribed rate (blue polygons), and pressure (red line) builds to a peak at the breakdown pressure, then it drops, indicating the rock around the well has failed. Pumping stops and pressure decreases to below the closure pressure. During a second pumping cycle, the fracture opens again at its reopening pressure, which is higher than the closure pressure. After pumping, the fracture closes and the pressure subsides. The initial pore pressure is the ambient pressure in the reservoir zone.

pressive stress is the overburden stress, then the fractures are vertical, propagating parallel to the maximum horizontal stress when the fracturing pressure exceeds the minimum horizontal stress.

The three principal stresses increase with depth. The rate of increase with depth defines the *vertical gradient*. The principal vertical stress, commonly called the *overburden stress*, is caused by the weight of rock overlying a measurement point. Its vertical gradient is known as the *lithostatic gradient*. The minimum and maximum horizontal stresses are the other two principal stresses. Their vertical gradients, which vary widely by basin and lithology, are controlled by local and regional stresses, mainly through tectonics.

The weight of the fluid above a measurement point in normally pressured basins creates *in situ pore pressure*. The vertical gradient of pore pressure is the *hydrostatic gradient*. However, pore pressures within a basin may be less than or greater than normal pressures and are designated as underpressured or overpressured, respectively.

Beyond Fracture Initiation

At the surface, a sudden drop in pressure indicates fracture initiation, as the fluid flows into the fractured formation. To break the rock in the target interval, the fracture initiation pressure must exceed the sum of the minimum principal stress plus the tensile strength of the rock. To find the *fracture closure pressure*, engineers allow the pressure to subside until it indicates that the fracture has closed again (above). Engineers find the *fracture reopening pressure* by pressurizing the zone until a leveling of pressure indicates the fracture has reopened. The closure and reopening pressures are controlled by the minimum principal compressive stress.

Therefore, induced downhole pressures must exceed the minimum principal stress to extend fracture length.

After performing fracture initiation, engineers pressurize the zone for the planned stimulation treatment. During this treatment, the zone is pressurized to the *fracture propagation pressure*, which is greater than the fracture closure pressure. Their difference is the *net pressure*, which represents the sum of the frictional pressure drop and the fracture-tip resistance to propagation.

Keeping Fractures Open

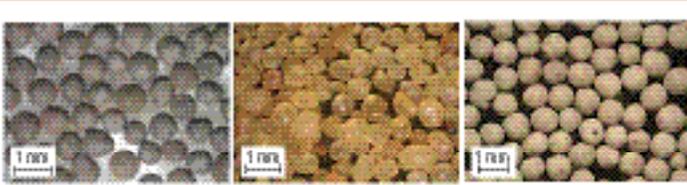
The net pressure drives fracture growth and forces the walls of the fracture apart, creating a width sufficient to allow the entry of the *fracturing slurry* composed of fluid and *proppant*—solids that hold the fracture open after pumping stops.

Once the pumping is halted, the pressures inside a fracture subside as the fluids either flow back into the well or leak away into the reservoir rock. This drop in pressure allows the fracture to close again. To ensure that fractures stay open, engineers inject additional materials, depending on lithology. In sandstone or shale formations, they inject proppant—sand or specially engineered particles—to hold fractures open (**below**). In carbonate formations, they pump acid into the fractures to etch the formation, creating artificial roughness.

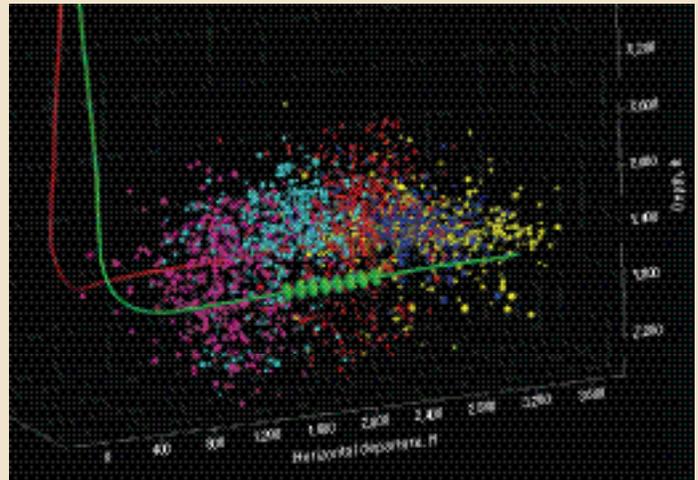
The stimulation treatment ends when the engineers have completed their planned pumping schedule or when a sudden rise in pressure indicates that a *screenout* has taken place. A screenout is a blockage caused by *bridging*—accumulation, clumping or lodging—of the proppant across the fracture width that restricts fluid flow into the hydraulic fracture.

Controlling Hydraulic Stimulation

Stimulation engineers maintain a constant rate of fluid injection. The volume injected includes the additional volume created during fracturing and the fluid loss to the formation from *leakoff* through the permeable wall of the fracture. However, the rate of fluid loss at the growing fracture tip is extremely high. Therefore, it is not possible to initiate a fracture with proppant in the fracturing fluid because the high fluid loss would cause the proppant at the fracture tip to reach the consistency of a dry solid, causing bridging and screenout conditions. Consequently, some volume of clean fluid—a *pad*—must be pumped before any proppant is pumped.



^ Proppant. Several proppant types, including high-strength bauxite (*left*), resin-coated silica (*middle*) and lightweight ceramic (*right*), are pumped into fractures to maintain open fractures for enhanced hydrocarbon production.



^ Microseismic monitoring of multiple-stage hydraulic stimulation. Analysis of microseismic data provides operators with information about the effectiveness of hydraulic stimulation treatments. In this example, five fracturing stages were pumped into the treating well (red line) while being monitored from a second well (green line with location of geophones shown as green disks). Microseismic events during stages 1 through 5 are indicated by the yellow, blue, red, cyan and magenta dots, respectively. Real-time microseismic monitoring may allow completion engineers to adjust operations during execution to improve the effectiveness of the treatment.

When designing a hydraulic fracture treatment, engineers must establish the leakoff rate and volume of the pad in relation to the timing of slurry and proppant injection so that when the fracture reaches its designed length, height and width, the first particle of proppant reaches the fracture tip. To design a hydraulic fracturing job, engineers must understand how pumping rate and stimulation fluid properties affect hydraulic fracture geometry and propagation within the in situ stress field to achieve a targeted propped fracture length.

Operators design stimulation treatments to control fracture propagation and to ensure that the hydraulic fracture stays within the reservoir and does not grow into the adjacent formation. To reduce this risk, operators monitor fracture growth. As fracturing fluid forces the rock to crack and fractures grow, small fragments of rock break, causing tiny seismic emissions, called *microseisms*. Geophysicists are able to locate these microseisms in the subsurface (**above**). Laboratory and field data have shown that these microseisms track growing fractures. Armed with the knowledge of the direction of fracture growth, engineers may be able to take action to steer the fracture into preferred zones or to halt the treatment before the fracture grows out of the intended zone.

The propagation of hydraulic fractures obeys the laws of physics. In situ stresses control the pressure and direction of fracture initiation and growth. Engineers carefully monitor the stimulation process to ensure it goes safely and as planned.