

# Geology and Geometry: A Review of Factors Affecting Hydraulic-Fracture Effectiveness

Thousands of wells are hydraulically fractured in the Appalachian basin each year with little clear understanding of what the resulting fracture actually looks like. A number of subsurface features exist that can influence the ultimate dimensions and orientation of a created fracture. It is necessary that the stimulation design team understand the influence these features can have on the path of a subsurface hydraulic fracture.

### Introduction

The majority of Appalachian basin reservoirs require some type of stimulation to be economical. Because neither the reservoir nor the created fracture can be seen or assessed with any real certainty, it is necessary to make assumptions about how the reservoir geology will respond to stimulation. Some assumptions that have been accepted over the years were controversial at first but have gained general acceptance over time. Other design factors are the result of local conclusions based on the results of treatments that have been refined through years of modification.

Traditional methods for predicting fracture growth include computer modeling, treatment-pressure analysis, radioactive tracers, and well testing. Microseismic imaging, a technique that images the created fracture by monitoring seismic or microearthquake “events” during the treatment from an array of sensors in an offset wellbore, has gained wide acceptance over the past 5 years as

a reliable method of determining created-fracture geometry.

These measured created-fracture-geometry results need to be related to production from the stimulated intervals to determine fracture effectiveness. Where production improvement is obvious, the stimulation style usually will be accepted and applied over a large region rather quickly. This can be seen in the shallow reservoirs of the Bradford group, where operators are steadily increasing the number of fracture stages, which directly correlates to increased production.

However, for deeper horizons, there are few documented cases in which production results have been rigorously shown to correspond to certain stimulation-treatment designs. The highly competitive nature of regional leasing and the difficulty in obtaining good treatment data and production information make correlating job type and profits a daunting task. A good first step is to better understand the created-fracture geometry for a particular fracturing style in a given reservoir.

### Basic Fracture-Growth Concepts

It is generally accepted that hydraulic fractures propagate perpendicular to the least principal stress. It follows that in shallower environments where the least principal stress is vertical, a fracture will grow horizontally. At some depth, where the increase in overburden causes the least principal stress to be horizontal, the predominant fracture-growth geometry will be vertical. It follows that a hydraulic fracture will respond to stress and propagate in the direction of least resistance. Variations in stresses between different lithologies in vertical rock sequences can cause fracture growth in a contained manner and generate length or allow the fracture to grow vertically upward or downward. Compounding the difficulties in attempting to predict how a fracture will grow are the many other features that can be present such as faults, natural fractures, bed laminations,

and other reservoir characteristics that would be difficult to know or predict from the surface.

**Inferring Fracture Geometry.** Direct far-field fracture-monitoring techniques (passive microseismic and downhole tilt) hold the promise of measuring the created fracture definitively. These techniques are relatively expensive and require an optimum situation where the tools to image the fracture are placed in an offset wellbore at a distance sufficiently close to detect the signal from the created fracture. It is anticipated that refinements of these techniques will allow imaging from the treated wellbore itself in the near future.

**Pressure Methods.** Fracture-geometry development during a fracture treatment is inferred by monitoring and analyzing the pressure of the injected fluids. The most common interpretation of this type is the Nolte-Smith plot in which inferences are made about fracture geometry from changes in bottomhole pressures. Ideally, the pressure must be measured as close to the actual fracture as possible.

### Radioactive-Tracer Surveys

Radioactive tracers can be added to the sand stages of a stimulation treatment and are transported and placed with the proppant pack. A logging tool is run over the interval after the job to determine where the tracer-laden proppant is placed. The main limitation of this technique is that the logging tool has a relatively shallow investigation depth and will image the fracture only very near or directly adjacent to the wellbore.

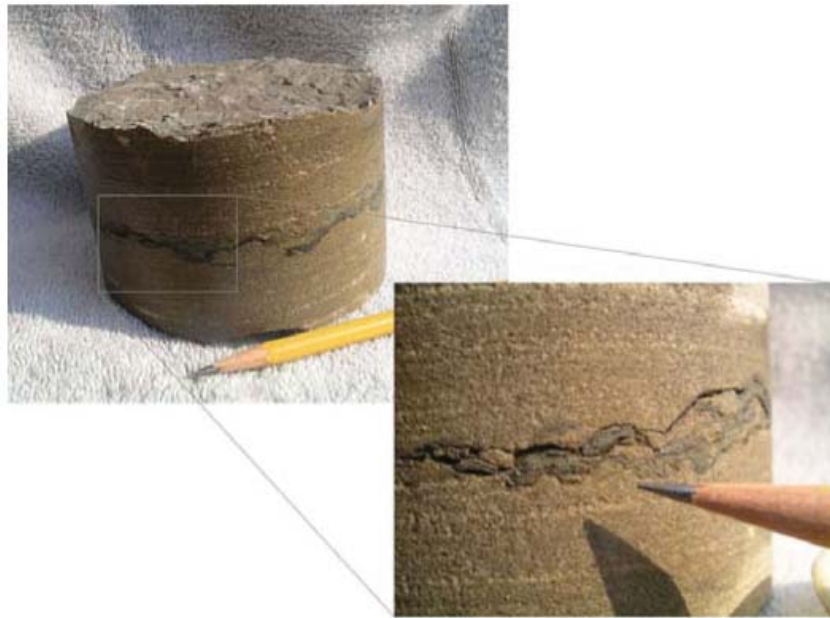
**Computer Fracture Models.** Computer models can reflect a wide variety of geometries. These models are particularly sensitive to assumed, but often not actually measured, subsurface stresses. For this reason, a computer model of a particular job design can give a false sense of frac-

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*For a limited time, the full-length paper is available free to SPE members at [www.spe.org/jpt](http://www.spe.org/jpt). The paper has not been peer reviewed.*



**Fig. 1—Thin shale bed in core.**

ture-design effectiveness. It is simple to see the error that could be made if it were assumed that a particular job was contained within the reservoir when the fracture actually grew into bounding layers. Understanding and predicting how hydraulic fractures grow is critical to maximizing field recovery.

#### Determining Fracture Geometry

**Microseismic Imaging.** Passive microseismic imaging of hydraulic-fracture treatments, while widely used in other parts of North America, has not seen general application in the Appalachian basin. The microseismic mapping process detects and plots in 3D space microseisms that are microearthquakes induced by changes in stress and pressure associated with hydraulic fracturing. These microearthquakes are slippages that occur along pre-existing planes of weakness (e.g., natural fractures) and emit seismic energy that can be detected at nearby seismic receivers. If an array of triaxial receivers is situated at a depth near the hydraulic fracture, compressional and shear waves can be detected and event locations can be calculated. These microseisms are extremely small, and sensitive receiver systems are required to obtain accurate results.

These microseismic data can reveal many fracture characteristics including azimuth, height, and symmetry. Of particular importance is the ability of microseismics to define the complex nature of fracture growth as it intersects natural subsurface fractures and differing stress zones. Often it is discovered

that multiple fractures are created where it was thought single fractures existed.

**Tiltmeter Fracture Mapping.** Tiltmeter fracture mapping is used to infer fracture geometry by measuring fracture-induced rock deformation. The induced-deformation field radiates in all directions and can be measured either downhole with wireline-conveyed tiltmeter arrays or with a surface array of tiltmeters.

#### Upper Devonian Sands

The Upper Devonian sands that are the target in the Linden Hall prospect can be compared with similar updip shallower Upper Devonian sands in northwestern Pennsylvania. In the case of the shallower Upper Devonian sand targets, stimulation treatments have evolved over the years to maximize production. These sands are on the order of tens of feet in thickness and have poor vertical permeability as a result of very thin but continuous shale breaks and many heavy-mineral microlaminations.

Core photos (**Figs. 1 and 2**) show some of these very-thin low-permeability layers. Heavy-mineral layers appear as the many dark horizontal lines that cross the cores. There also are many slightly thicker horizontal shale layers that can be seen cutting the core. These layers have extremely low permeability and are effective “gaskets” between the many microreservoirs stacked vertically in the reservoir. In a typical gamma ray log run at a normal scale, these features would not be evident. The standard tool and analysis

software would average the contributions of these thin features.

**Different Depth Bradford Reservoirs.** A typical stimulation technique used in the shallower (less than 2,000 ft) Upper Devonian reservoirs in the Bradford, Pennsylvania, region is generally referred to as “open-hole” or “packer and plugback” fracturing. In this type of stimulation, the zone to be stimulated is uncased and “open.” Multiple intervals are stimulated and “notched” with a downhole sandblasting technique. A notch tool with small carbide nozzles is attached to the bottom of the tubing string and rotated as air and sand etch a ring or notch into the formation sand. The notch usually has a 1- to 2-in. depth and acts much as a perforation in a cased well (as the initiation point for the treatment slurry). The notches usually are treated separately and progressively down the well, a stage at a time. The stages are isolated by use of a tension-set openhole packer and a pea-gravel filler referred to as “plugback.” After notching, the well is filled with plugback to a point above the uppermost notch. The packer is reverse circulated below the notch to be treated, then pulled above the notch and set. This process allows many zones to be treated discretely. These multiple fractures usually do not communicate during pumping, indicating that the fracture geometry is horizontal or highly inclined. Although in use for years, this technique continues to be refined as additional production results are correlated to the number of stages.

**Geology and Stimulation Design.** The nature of the Upper Devonian rocks is such that barriers to vertical permeability, both microlaminations and shale layering, must be accounted for in any stimulation design. Even in thin sand beds, a large portion of the reservoir might not be in communication with the hydraulic fracture because of these features. Correlation of production and number of stages has revealed that the controlling factor in maximizing well potential is the total number of stages.

The intervals investigated were typical Upper Devonian sandstones of the Tiona group and Bradford group in McKean County, Pennsylvania. Twenty-eight wells that had been fractured previously were stimulated in zones that had not been completed when the earlier treatments were done. Four to 11 additional stages per well were added. Twenty-seven of the 28 wells experienced a production increase. The first 3 months’ production per well was increased from 12 to 80 Mcf/D. The average



**Fig. 2—Thin lamination in core.**

production increase was 35 Mcf/D. Average well life was extended more than 5 years, and most paid out in less than 12 months.

**Deeper Reservoirs.** The most common stimulation style for the deeper reservoirs of the Upper Devonian is referred to as “ball and baffle.” The well is cased, cemented, and perforated by use of jet perforators. The unique component is the use of multiple, sequentially smaller, restrictions called baffles, placed in the casing as it is run. This technique allows isolation of zones during the treatment by dropping progressively larger “fracture balls” that land on the strategically placed baffles.

In shallower Devonian sand reservoirs, it is necessary to complete every discrete reservoir with a stage to maximize recovery. In deeper settings, the fracture geometry needs to be related to the reservoir-rock geology. In this case, it is vital to determine the fracture height because the fracture could grow vertically through several target zones from a single stage. In this case, it is necessary to decide if one stage can serve to stimulate several zones in a more cost-effective manner than pumping multiple stages. To maximize production, the hydraulic fracture has to not only penetrate a zone but deliver proppant that will make the created fracture conductive.

**Recent Imaging Developments.** Microseismic fracture imaging of the Linden Hall prospect in the Hunker field has added a large piece to the puzzle of how hydraulic fractures grow in some reservoirs of the

Appalachian basin. The microseismic images of the created fractures in the Linden Hall project allow comparison with and calibration of some of the simpler techniques. Preliminary comparisons have led to the following conclusions.

1. Uncalibrated computer models gave a more-contained fracture aspect ratio than actually was created.
2. Calibrated computer models more closely resemble the created geometry as illustrated by microseismic mapping.
3. Vertical penetration of fractures into sand bodies, both above and below, was greater than previously thought.
4. Initial pressure analysis of the treatment showed that a close understanding of all contributing variables is necessary to give the technique any validity.
5. Tracer studies would not have predicted actual fracture geometry in the far field because fracture growth would have been too far away for the receiver to detect the radioactive material.

Imaging of Upper Devonian sand horizons in the Linden Hall project points out the need to evaluate whether the overlap of fractures from discretely fractured zones has a negative or positive effect on well performance. It is necessary to determine whether the hydraulic fractures actually intersect or exist in parallel but unconnected geometries. The implications of either scenario are not trivial because they pose many questions for the design team. Production testing will be performed on the Linden Hall project wells to understand the production from each stage.

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