Operators Seek Fracture Consistency

Heterogeneity and variability in rock composition, texture and stress have led to inconsistent production from horizontal shale wells. Achieving a better understanding of the challenges this variability presents to horizontal multistage completions is leading to advanced measurements and processes that achieve more consistent production results and improved fracture efficiency.

By Kyel Hodenfield

PARIS—Advancements in the process efficiency of horizontal well drilling and multistage hydraulic fracturing have enabled the vast economic development of unconventional shale reservoirs in North America. A manufacturing approach to well construction—developed through cooperation between service providers and operators—has driven down costs at an impressive pace; however, further focus is required to achieve better and more consistent performance on production results, as many wells are not economic, especially at current gas prices. This inconsistency of production results has been experienced in all the basins across North America, and provides an opportunity for the next process improvement in the economics of unconventional plays.

Hundreds of new-generation production logs have been run in unconventional wells. Analyzing these logs indicates that 15-20 percent of the fracture stages and 35-40 percent of the perforation clusters do not contribute to production. Published numerical simulations of shales have shown that as much as 75 percent of each hydraulic fracture does not contribute to production. Often, the fracture is not propped effectively, is isolated from the main fracture or does not clean up effectively. Some imbibition of stimulation fluids takes place, although testing indicates an imbibition rate of less than 5 percent of the total fracturing fluid volume.
These observations suggest the majority of the volume pumped contributes to the generation of surface area, but only a small fraction of created surface area contributes to production. This information, even if taken conservatively, strongly indicates opportunities for improving production from multistage hydraulic fracturing. The industry needs to make the next process change to improve the effectiveness of fracturing stages and perforation clusters, and improve production efficiency.

Effective hydraulic fracturing of horizontal wells is challenging for several reasons, including:
- Basin heterogeneity;
- Rock composition and texture;
- Rock anisotropy and stress;
- Effects of horizontal stresses and breakdown pressures on near-well fracture propagation;
- Well landing point and horizontal placement variations; and
- Overflushing and flowback.

**Heterogeneity And Composition**

Vertical and lateral heterogeneity of material properties in shale results from depositional and post-depositional processes that include diagenesis, interaction with organisms, thermally activated geochemistry and movement of mineral-laden fluids. The large surface area of the fine-grained sediment facilitates chemical interactions with other minerals and organic matter that result in the precipitation of biogenic minerals such as silica, calcite, and pyrite. Even when initial deposition is homogeneous and uniform, the rock can become transformed over time to develop considerable vertical and lateral heterogeneity. The result is a volumetrically heterogeneous system that contains various degrees of good- to poor-reservoir-quality rocks with stacking patterns that need to be understood for optimizing horizontal completions.

Vertical heterogeneity is evident from log and core measurements, whereas lateral heterogeneity becomes apparent using multwell analysis, horizontal log evaluation and integration with seismic data. Basin heterogeneity in material properties largely is responsible for the large production variations not only from well to well, but also across the lateral well bore. The rock heterogeneity complicates the completion of horizontal well bores because it introduces a variability that is unanticipated.

Figure 1 shows the high degree of variability in production from a sample of more than 600 horizontal Barnett Shale wells. Because of heterogeneity, production can vary tenfold within a short distance. Data acquisition and integration strategies are key methodologies to target the right areas for development programs. Integrated processing of core, log and seismic data can provide valuable input to 3-D geologic models that will help choose the best drilling locations.

Basin heterogeneity results from changes in the rock’s composition and texture, which are the primary drivers for all material properties. Composition includes both mineral and organic volumes. The diagenetic processes include strong interaction between clays, mineral cements (often biogenic) and organic matter. The facies is strengthened by the influx of microcrystalline minerals—such as silica, calcite and pyrite—during the maturation process.

Cementation of these minerals on the clay-rich system strengthens and hardens the rock, preventing compaction and resulting in good reservoir quality. Determining the clay’s mineralization/maturity is perhaps more important than its volume. Immature clays such as smectite are particularly detrimental to hydraulic fractures as they lead to conductivity barriers that may pinch off sections of good reservoir quality from the well bore. Volumes of immature clay above 4 percent have proven to be detrimental to well productivity, and concentrations greater than 8 percent are likely to result in unsuccessful stimulation.

Texture includes the presence of microtexture such as lamination, interfaces, planes of weakness, and grain-to-grain contacts and distribution—features generally visible only in core samples. Texture also includes larger-scale features such as lithologic contacts and natural fractures. Experimental observations on large blocks of shale show that interfaces are sources of hydraulic fracture stepovers and branching. When the reservoir texture is complex, the hydraulic fractures also are complex, making the material more difficult to fracture.

**FIGURE 1**

Best-Year Production Variability Map of Barnett Shale Horizontal Wells
Natural fractures, mostly mineralized, are apparent in cores and well bore images ranging from microscopic to as wide as 0.25 inches. These fractures often can facilitate hydraulic fracture complexity by dilating during the fracturing process. This dilation will be a function of their orientation to the stress field and the variations in horizontal stresses. In addition to natural fractures, subtle textural features can induce complexity to the hydraulic fracture system. Near to the bore hole, these fractures can be problematic as perforating on a fracture swarm may result in narrow fractures because of competition for fluid. This can lead to high injection pressures and inability to place proppant.

Most importantly, stratigraphic sequence boundaries, mineralized fractures and other weak interfaces reorient locally the direction of fracture propagation, resulting in fracture branching, fracture stepovers and general fracture complexity. These features may promote height growth containment and higher surface area for reservoir volume, but also promote the development of obstacles and constrictions for proppant transport. The creation of surface area outside good-quality rock (i.e. lack of containment) and the creation of unsupported surface area (poor proppant transport) are two fundamental conditions of poor fracture efficiency and loss of surface area.

Rock composition and texture complicate horizontal completions by introducing variability. This leads to changes in fracture propagation and containment that are not anticipated but can be clearly observed during microseismic monitoring.

Stresses

Organic-rich mudstones can exhibit pervasive and strong anisotropy in elasticity, tensile/compressive strength, acoustic velocity and permeability that arise from their laminated depositional texture and their final diagenetic texture. This results in a contrast in elastic properties between directions parallel and perpendicular to bedding that can be as high as 400 percent (Figure 2).

Changes in properties related to direction to bedding result primarily from changes in texture even when composition may be relatively the same. Anisotropy in mechanical properties substantially changes the rock stress-strain relationship, and affects the development of far-field stress, near-well bore stress concentrations, breakdown pressure, hydraulic fracture width, potential for solids production and stability of the completion.

As the magnitude of the elastic anisotropy increases, the difference in Young’s modulus and Poisson’s ratio measured normal and parallel to bedding also increases. This impacts far-field completion parameters of fracture containment, fracture complexity, proppant transport and fracture closure stress, as well as near-well bore completion parameters of breakdown pressures, near-well-bore fracture width and proppant entry. Because of its strong influence in near-well-bore and far-field completion parameters, adequate characterization of elastic anisotropy is of fundamental importance for completion design in tight shales.

In the absence of tectonic deformation, the two horizontal stresses that develop in a layered formation are uniform. Structural deformation such as folding leads to differences in minimum and maximum horizontal stresses. When considering stress variations along horizontal well bore trajectories, these will change with changes in rock texture and composition, and when the lateral bore hole intersects multiple beds (Figure 3). In addition, in regions subjected to tectonic deformation, the two horizontal stresses will be different in proportion to their elastic anisotropic properties.

Heterogeneity in texture and composition, elastic anisotropy of the rock types, textural complexity and structural deformation by tectonic strains are the fundamental sources of in situ stress. As rock types change along the well bore, so do local stresses. In addition, the presence of the well bore and its mode of completion (including open hole, cased or cemented, uniform or nonuniform cementing) creates different local stress conditions. This results in varying stress and breakdown pressure regimes along the horizontal well and complicates the completion design. Understanding the rock and the geologic conditions of basin development are fundamental for evaluating near-well-bore, and far-well-bore stress conditions, and for designing effective completions.

As a well bore is drilled, the stresses previously carried by the rock are redistributed around the bore hole wall. In a typical extensional stress state (overburden stress greater than horizontal stresses), compressive stresses increase at the sides of the well bore to compensate for the missing material, and are maximum at the well bore sides and minimum at the top and bottom. For example, in the Barnett Shale, anisotropy and relatively low horizontal stresses reduce the compressive stresses to the point that the top and bottom of the well bore are placed in tension, often resulting in “drilling induced fractures” parallel to the well bore—often evidenced on imaging tools.

The near-well-bore conditions have important consequences for hydraulic

### FIGURE 2

**Ratios of Horizontal and Vertical Young’s Modulus (E₁/Eᵥ) and Poisson’s Ratios (μ₁/μᵥ)**

<table>
<thead>
<tr>
<th>#</th>
<th>Matrix Composition</th>
<th>E₁/Eᵥ</th>
<th>μ₁/μᵥ</th>
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<tr>
<td>1</td>
<td>Carbonate</td>
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<td>0.97</td>
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<tr>
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<td>Calcareous Mudstone</td>
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<td>0.88</td>
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<tr>
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<td>Silty Mudstone</td>
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<td>4</td>
<td>Siliceous Mudstone</td>
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<td>1.47</td>
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<tr>
<td>5</td>
<td>Organic/Argillaceous Mudstone</td>
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<td>1.34</td>
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<td>8</td>
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</tr>
</tbody>
</table>

### FIGURE 3

**Tangential Stress Concentration for Barnett Shale Horizontal Well**

- **2,000** to **6,000**
- **Hoop_Map**

- **T**
- **H**
- **Stress Concentration**
- **Permeability**
fracture initiation/propagation as the stress around the well bore is different than the far field. This difference usually results in near-well-bore fracture tortuosity as the near-well-bore axial fracture reorients to the far-field stresses once away from the stress concentration. The stress perturbation decays rapidly away from the bore hole, typically within three diameters. The near-well-bore effect and its variation along the lateral well bore will impact well productivity if not accounted for in the completion design.

**Landing Point And Overflushing**

Unconventional reservoir sections often are more than 100 feet thick. The landing point and horizontal placement within the reservoir have proven to be a key component in a well’s production success. Given the variability in rock texture and composition and stress, proper well bore landing considerably improves near-well-bore completion quality.

The challenge for well production is to fully contact good quality reservoir rock with hydraulic fractures. This far-field problem can be difficult to address. The landing point addresses the near-well-bore problem, and should be chosen to maximize the connectivity between the well bore and the created hydraulic fractures. To achieve this in a rock type that develops high near-well-bore fracture width, it may not be necessary to land the lateral in rock with the highest reservoir quality, but rather in rock that will support high connectivity to the reservoir, high fracture width and minimum propensity of fracture closure during production.

Certain completion and flow back procedures can have an adverse effect on near-well-bore fracture conductivity. Overflushing as a result of the horizontal completion procedures may be detrimental to near-well-bore conductivity as proppant is potentially flushed away from the fracture causing a pinch point near the well bore.

During well flow back/cleanup, the propensity for solids or proppant production is predominantly a factor of the large drawdown pressure, which is otherwise desirable to accelerate the production of fracturing water and promote higher initial production. A large drawdown can cause solids production that results from a tensile failure (spalling) at the fracture face. Optimizing a production scheme is possible once the variability of parameters such as reservoir pressure, rock permeability and rock tensile strength are quantified along the well bore, since these effects will vary from perforation cluster to perforation cluster.

**Potential Solutions**

A successful organic shale completion requires appropriate development and retention of fracture containment, complexity and conductivity. These hydraulic fracture attributes depend on the rock properties of composition, texture, and in-situ stress. In-situ stress depends largely on the rock properties—predominantly elastic anisotropy and an understanding of the geologic setting. The system is heterogeneous, thus texture, composition and stress change laterally along the length of the well.

Rock composition and texture, and in situ stress are the fundamental properties needed to improve the effectiveness of fracturing stages and perforation clusters, and improve production efficiency. The heterogeneous nature of mudstones in both the vertical and lateral directions means that economic production requires assessment of two fundamental conditions: reservoir quality and completion quality.

Reservoir quality (RQ) is the combination of properties that lead to hydrocarbon storage and producibility—including hydrocarbon-filled porosity, fluid saturations, effective permeability, organic content and pore pressure. Heterogeneity of rock properties often is characterized by gradational changes in RQ. The changes may be subtle, but are sufficient for some of the lithofacies to develop considerably better reservoir potential than others.

Completion quality (CQ) is the combination of properties that lead to fracture surface area contacting the reservoir during stimulation and maintaining this contact once the well is placed on production. Properties impacting the former include minimum horizontal stress contrast and fracture containment and textural features to influence fracture complexity. Properties impacting the latter include rock-fluid sensitivity; proppant embedment/crushing/production; loss of fracture-face permeability by inbibition or water retention; solids/fines production; and salt or scale precipitation along the fracture’s conductive section. Because of the large surface area exposed to the fracturing fluid, even minor conditions of rock-fluid sensitivity may result in severe consequences to overall production.

CQ can be subdivided into near-well and far-field, and the key CQ parameters of both are mentioned above. Poor CQ parameters in the near-field region can result in production pinch points with corresponding lateral production variation as these near-well CQ parameters change along the lateral.

Successful unconventional reservoir
production depends on the favorable co-existence of good RQ and good near-well and far-field CQ. When RQ is low, well productivity is poor regardless of the conditions pertaining to CQ. Conversely, regions where RQ is high but CQ is low present challenges and engineered completions are compulsory.

**Addressing RQ and CQ**

Employing means of addressing RQ and CQ variations can significantly impact a well’s productivity. Several steps can be taken to address both RQ and CQ; while not inclusive, they are the primary actions that operators can take to impact productivity.

The best method to determine the optimum landing point is to integrate core and wireline logging measurements from a vertical pilot well to determine the parameters of composition, texture, and stress. New geochemical logging tools, combined with density, provide accurate compositions. Fractures—the greatest influence on rock texture—have been detected accurately and quantified for years with microresistivity bore hole imagers. For accurate stress calculations, only new-generation sonic logs can measure horizontal shear slowness accurately and account for anisotropy in mechanical properties that dominates shale. Stress calculations are best calibrated with either cores or in situ stress measurements.

To understand and quantify variability, the logs are used to nonsubjectively define fundamental rock classes by their bulk log response behavior through a multivariate statistical analysis. Most importantly, the subtle changes that differentiate diagenetic facies can be identified systematically and used for sample selection, testing and the development of core/log/seismic based 3-D reservoir models (Figure 4). RQ and CQ measurements from the logs are calibrated and supplemented by core data. In particular, important CQ data that can be best acquired from core are fluid sensitivity data (embedding, fines generation) and oriented tri-axial geomechanics, which are used to calibrate anisotropic stress outputs. New Fourier Transform InfraRed analysis more accurately quantifies smectite and total clay volumes from core samples.

These anisotropic stress parameters are input to hydraulic fracture simulation software to estimate hydraulic fracture half-length, height and width. Figure 5 presents hydraulic fracture height simulations for a Barnett Shale target, contained within the horizontal red lines. The hydraulic fracture simulations employ a fully 3-D, finite difference, planar simulator based on the anisotropic closure stress model. Each simulation represents a perforation depth. The downward fracture height growth into the potentially water-producing Ellenburger formation varies with lateral landing point (blue dot). These results are used to optimize the landing point and lateral placement of the well bore. The 3-D geological model will identify the areal extent and validity of this zone based on the heterogeneity.

Once the target is identified, geosteering techniques must be tailored to each specific basin through a selection of logging-while-drilling, cuttings, and 3-D models. It has been demonstrated with production data that, in most reservoirs, proper landing and placement of the well bore will have a dramatic effect on production results.

**Staging Stimulations**

Measurements of composition, texture, and stress made in the lateral with LWD now are used to determine how to stage the hydraulic stimulations and where to
place the perforation clusters; as well as provide stimulation volumes and injection rates.

An example from the Eagle Ford formation (Figure 6) shows how understanding RQ and CQ can be used to improve completion designs using a rigorous algorithm to locate perforation clusters and stage placements. The well completion was optimized based on composition, stress, and the other CQ parameters of anisotropic Young’s modulus and Poisson’s ratio. A bore hole imager for fracture quantification was not available on this well. The figure shows a view of an Eagle Ford completion with geometrically placed perforation clusters (top) compared with an engineered completion with selectively placed perforation clusters using the horizontal well-staging algorithm (bottom).

In both wells, 17 hydraulic fracturing stages were used with four perforation clusters per stage. In the engineered completion design, logs were used to define RQ and CQ to define the stages.

The final and critical task was to select the locations of the perforation clusters to ensure that all stages should be equally good. This process utilizes the same CQ outputs as the staging process to place the perforations in similarly stressed rock in each stage. Using this rigorous completion optimization algorithm resulted in a 20 percent increase in initial production compared with the first well. Applying the approach on subsequent wells resulted in similar production increases.

Channel Fracturing

A novel combination of chemistry, fiber and process control has been developed to target issues related to the high percentage (up to 75 percent) of the created fracture that is not contributing to production—a key indicator of far-field CQ not being addressed by current slick-water completion designs. This process greatly improves the spatial distribution of fracture conductivity by improving proppant transport, and through creating high conductivity open channels within this distributed proppant pack (Figure 7).

Production results over a number of wells in multiple field studies have shown an average production improvement of 31 percent and increased recovery of the injected fluid. The process uses, on average, 40 percent less water and 30 percent less proppant, reducing cost and truck traffic.

Most fracture conductivity damage occurs during the flow-back process while trying to overcome friction and capillary forces to clean the well bore and fractures. An engineered approach with autochokes, multiphase meters and measurements has had early success in the field. Sampling and analysis of solids has shown that excessive drawdown on the well actually produces back scales (incompatible fluids), proppant (whole and crushed) and formation fines to the point of well bore damage. Sampling and analyzing fluids has in some cases indicated a loss of fracture containment through analysis of dissolved salts attributable to a particular formation.

Heterogeneity and variability in rock composition, texture, and stress have led to inconsistent production from horizontal wells in organic mudstones. A better understanding of the challenges that horizontal multistage completions face as a result of the variability has led to advanced measurements and processes to achieve more consistent production results. Applying new technologies has enabled operators to eliminate the large number of perforation clusters that do not contribute to production and improve fracture efficiency.

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