Optimizing Completion Strategies for Fracture Initiation in Barnett Shale Horizontal Wells

The Barnett shale is an unconventional gas reservoir, estimated to extend over 54,000 sq miles. To improve well economics and reduce the number of surface locations in populated areas, there has been a rapid increase in the number of horizontal wells drilled and completed. Inefficient fracture initiation is the largest problem encountered when completing horizontal Barnett shale wells. This field study examined 256 horizontal wells to identify the causes of these near-wellbore issues and to recommend corrective measures for future completions.

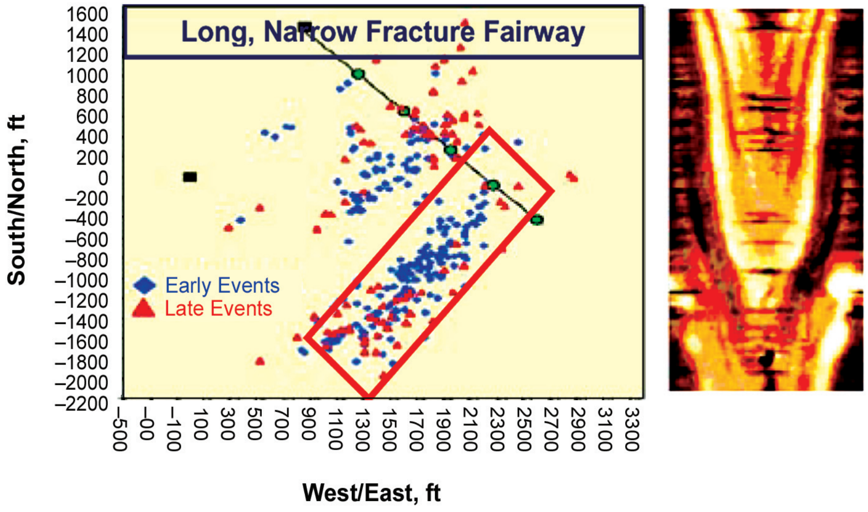

Fig. 1—High stress anisotropy.

Introduction

The Barnett shale is a Mississippian-age marine shelf deposit in the Fort Worth basin, and this study concentrates on wells in Denton, Wise, and Tarrant counties. The Barnett shale in the core area is 300 to 500 ft thick. Permeabilities range from 0.00007 to 0.0005 md with porosities ranging from 3 to 5%. The Barnett shale is abnormally pressured in this area. Commercial production is achieved through hydraulic-fracture treatments.

Before 1997, Barnett shale wells were completed with massive hydraulic-fracture treatments consisting of crosslinked gelled fluids and large amounts of proppant. Because of difficulties with effectively cleaning up fracture damage from the crosslinked gel and the high cost of these massive stimulation treatments, the wells were not as economical as desired. In 1997, large-volume, high-rate slickwater fracture-stimulation treatments were sought as a less-expensive alternative. While well performance was not increased drastically by use of slickwater, completion costs were reduced by approximately 65%. In 2002, horizontal wells were introduced to increase wellbore exposure to the reservoir. The first horizontal wells had three times the estimated ultimate recovery at twice the well cost compared to vertical wells.

In the early stages of horizontal completions, the wells were divided equally between uncemented and cemented laterals. Shorter laterals that required single stimulations were uncemented, and cemented laterals were implemented when the stimulation design required multiple stages because of an increased lateral length. Composite bridge plugs were used for zonal isolation. Fractures in uncemented laterals are prone to grow in such a way that unstimulated volumes, or "gaps," are left in the reservoir, which equates to a smaller overall fracture area and reduced productivity.

As drilling progressed outside the core area and acreage was available to accommodate longer laterals, the number of cemented horizontals surpassed the number of uncemented horizontals. However, the increase in cemented laterals also yielded a higher rate of inefficient fracture initiation than seen in uncemented laterals. In 2005, more than one in four cemented horizontals experienced fracture-initiation problems compared to one in 25 for uncemented laterals.

Inefficient fracture initiation can be defined as the lack of sufficient fluid-injection rates resulting in the inability to pump the designed proppant concentrations, delivering an ineffective fracture network. The stimulation job typically will be characterized by high pumping pressures and occasionally abnormal fracture gradients. Inefficient fracture ini-

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

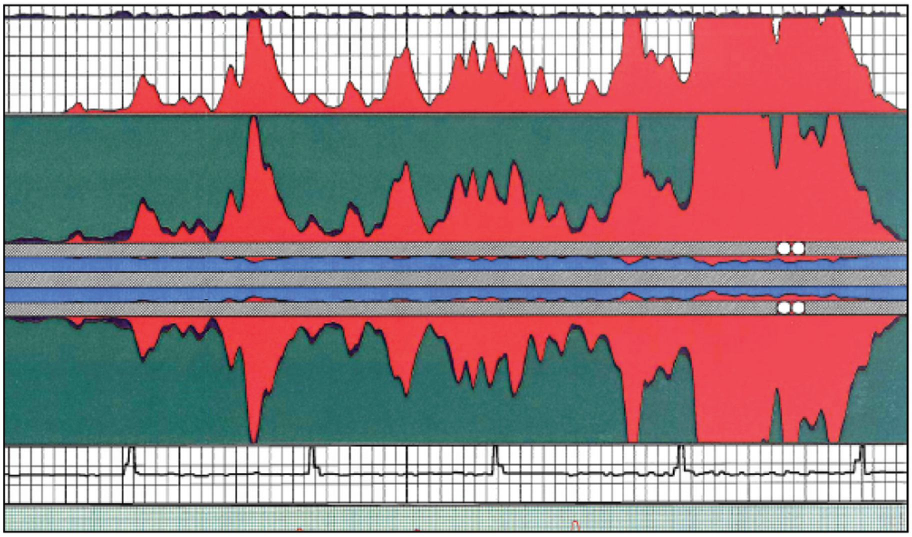

Fig. 2—Post-acid and -hydraulic-fracture chemical-tracer log on a single-cluster ASC horizontal well.

tiation can be related to cement design, perforation phasing, perforating lengths, cluster spacing, formation stresses, and pad design for the stimulation treatment. The cost incurred because of these problems is quite significant. The goal of this study was to recommend an optimized completion strategy that would reduce the completion cost of cemented horizontals, increase stimulation coverage, and maintain a trouble-free fracture schedule.

The study was divided into two segments. The first segment was problem assessment, which evaluated 154 horizontal wells, 31 of which displayed inefficient-fracture-initiation issues. Correlations were developed using field data to identify probable causes and possible solutions. The second segment included 102 horizontals in which these new strategies were implemented. Fracture-initiation problems were reduced from 19.1 to 4.7%, a 74% improvement.

Barnett Shale Stress Variability

A common misconception when characterizing the Barnett shale is to classify and treat the rock along the wellbore as homogeneous. A horizontal wellbore was fractured in four stages, with the first stage having two perforation clusters. A prefracture instantaneous shut-in pressure (ISIP) was measured for all four stages to illustrate how stress varies along the horizontal. The ISIPs varied from 0.75 psi/ft at the toe section to 0.63 psi/ft in the heel section, and there was no consistent trend in the ISIP magnitude from toe to heel. As the state of stress varies along a wellbore, so will the types of problems with fracture initiation, job placement, and optimum job design.

Image logs recently have been used to determine qualitatively the states of stress in the wellbore. Faults, natural fractures, and hydraulic fractures can be seen in these images, and perforation placement can be optimized with this information. These images also can provide information about the stress anisotropy along the wellbore. **Fig. 1** shows an image along a Barnett horizontal. Fig. 1 displays only transverse fractures along this section of the horizontal well. This type of behavior is seen in areas with high horizontal-stress anisotropy. In this type of stress environment, longer and narrower fracture fairways are generated. High horizontal-stress anisotropy can result in high near-wellbore friction pressure losses and difficulty in placing proppant.

Perforations

Sufficient cluster spacing will prevent individual fractures from linking and allow multiple parallel fractures to extend without restricting fracture growth. In past microseismic studies, stress shadows have been shown to have both negative and positive effects. When perforation-cluster spacing is too close, the stress shadow can restrict growth in the middle cluster and increase growth disproportionately at the heel and toe perforations. However, if two perforation clusters are properly spaced and simultaneously competing, the fracture growth is enhanced in the orthogonal direction. Because fracture height is the smaller fracture dimension compared to fracture length, closure stress is influenced greatly by the fracture height and decreases as the distance between fractures increases. Fracture height is area dependent in the Barnett shale but typically ranges from 300 to 400 ft. After multiple microseismic studies, the optimal cluster spacing to reduce fracture interference is at a distance greater than 1.5 times the fracture height. The strategy implemented for the case study was to reduce the number of clusters per stage from three to one or two. Before the study, the average horizontal well had 2.7 fracture stages, and after transitioning to reduced clusters, the number of stages per well increased to 3.2. Earlier spacing was maintained at 1.5 times the fracture height.

To reduce the probability of creating multiple competing fractures, the perforation-cluster length should be less than four times the wellbore diameter. If the cluster length is less than four times the wellbore diameter, a single dominant fracture will be created. A characteristic of competing multiple fractures is high pressure with low injection rates. Before the case study, 71% of the fracture-initiation issues involved a perforation cluster length greater than four times the wellbore diameter, generally from 5 to 10 ft. The new strategy implemented was to keep perforation-cluster spacing to less than 4 ft. A comparison of the ratio of average treating pressure and average treating rate of fracturing treatments on wells where shorter clusters were used shows a 14% decrease in psi/(bbl/min) requirements. The shorter clusters will allow an appropriate number of holes for limited entry to be effective while also limiting cluster length. Limited-entry requirements for Barnett shale horizontals are designed to allow 2 bbl/min per perforation and a total perforation differential pressure greater than 500 psi.

Cementing

With cemented laterals dominating the statistics for fracture-initiation issues and the need for stage isolation becoming more important as the lateral length increased, the cementing strategy was closely examined to identify and address the issues causing stimulation troubles. An acid-soluble-cement (ASC) system was sought as a viable option to conventional cement slurries. An ASC slurry has an increased amount of calcium carbonate ($CaCO_3$) in the slurry. When in contact with hydrochloric acid, the cement will dissolve based on the solubility and contact time. The solubility capacity is a function of the $CaCO_3$ ratio and the contact time, which can be controlled with acid volume and pump rate.

The main concern with using an ASC blend was maintaining sufficient isolation by placing fractures at the desired distances apart, therefore preventing gaps while stimulating. The main objective when cementing laterals is to provide annular isolation between the perforation clusters. This allows the creation of independent hydraulic fractures at each perforation. By strategically placing perforations, stimulation gaps can be avoided along the lateral. ASC has the advantage of reducing the annular restriction common when perforations are not aligned with the top and bottom of the hole. When designing for limited entry with 60°-phased perforations, fluid will exit the wellbore on the side of the hole. This fluid must follow a tortuous path to get to the point of the wellbore where the hydraulic fracture initiates. Cement in the annulus can produce a choke effect that restricts fluid flow. Dissolving the cement provides conditions approaching open hole, while still providing annular isolation between perforation clusters. A comparison of the ratio of average treating pressure and average treating rate of fracturing treatments on wells cemented using a standard system and those using an ASC system shows a 17% decrease in psi/(bbl/min) requirements.

Chemical-tracer logs and cement-bond logs have been used to validate proper zonal isolation and determine the lateral length affected by contact with hydrochloric acid. A chemical-tracer log shown in **Fig. 2** clearly displays that sufficient isolation was attained and that ASC was dissolved behind the casing for approximately 150 ft. The largest gamma ray readings came from within a 30-ft range of the perforations, giving additional confidence that fractures can be placed at desired depths along the lateral.

Fracture-Design Changes

Acid with biodegradable ball sealers has been used in conjunction with ASC to reduce the amount of near-wellbore pressure drop between the pipe and formation. Typical acid volumes are between 1,000 and 2,000 gal per cluster stimulated. Crosslinked gels and 100-mesh sand have been used in the fracture pad stages. Initiating a hydraulic fracture with crosslinked gel increases the fracture width and subsequent rate of treating-pressure decay. This increased width has improved the ability to place proppant through the near-wellbore region. Use of 100-mesh sand in the pad stage has assisted in controlling the leakoff into a complex fracture system. Closely spaced hydraulic fractures or natural fractures activated during the treatment can reduce the average fracture width, making proppant placement more difficult. Many of these fractures can be bridged by 100-mesh sand, so that fewer, wider dominant fractures are present near the wellbore.

Conclusions

A two-part case study was undertaken to determine the causes of stimulation difficulties in cemented horizontal wells. The first part of the study examined 31 horizontal wells that displayed difficulties with inefficient fracture initiation. The second part of the study examined 102 horizontal wells comprising 300 fracture stages that used the best practices discovered in the first part of the study. The strategies implemented were successful at decreasing the probability of having an inefficient fracture initiation from 19.1% of the stages to the current rate of 4.7% of the stages—a 74% reduction. **JPT**