Real-Time Monitoring ‘Steers’ Fractures

By Deane Sparkman, Jamel Belhadi and George Waters

HOUSTON—The technique of using microseismic monitoring of hydraulic fracturing jobs has proven to be an effective way to see if the fractures propagate according to plan. By mapping the hydraulic fractures, operators have been able to identify untreated reservoir sections that can be targeted on subsequent treatments, as well as see whether a fracture intersects an aquifer or other geohazard, or perhaps another well.

Typically, an array of geophones is deployed in a nearby offset well. Initially, vertical wells were chosen, largely out of convenience. There were often many nearby vertical wells to choose from, and deploying on wireline was efficient and cost effective. However, after gaining experience in microseismic monitoring, many operators are deploying the seismic arrays in horizontal wells to take maximum advantage of the rich data sets that can be acquired. Pump-down techniques or downhole tractors are used to place the seismic monitoring equipment precisely in the horizontal observation wells.

Recently, powerful computers have been able to process the acquired microseismic data in real time, using a technique called StimMAP™ Live, which provides fracture mapping within 30 seconds of microseismic activity. Based on proprietary coalescence microseismic mapping (CMM) technology that enables fast and accurate processing of events, this diagnostic service provides a propagation map after each stage of a multistage frac job. This allows engineers to make decisions “on the fly” as the job progresses to improve fracture quality and reservoir contact.

Some of the changes operators have implemented on site as a treatment proceeds include the ability to alter the locations of perforations for the next stage, changing the shot density or perforation intervals, and changing the pumping schedule. These have added significantly to the value of the frac job.

Several new techniques have been enhanced by microseismic monitoring. One example is “zipper-frac,” a technique that involves alternating stages from two or three adjacent wells while holding pressure on the previously fractured well. This creates a complementary stress field around the well just stimulated, which prevents the fractures from the well that is being stimulated from intersecting those from the previous well. The result is thorough reservoir contact with no interwell contamination.

‘Steering’ Fractures

The industry is still learning all the benefits that can be obtained from real-time microseismic monitoring of hydraulic fractures. One of the most recent benefits is a combination with diversion technology to “steer” the fractures to contact specific reservoir volumes. With this ability, companies have been able to produce numerous, closely spaced fractures instead of a...
few deep, widely spaced fractures.

Studies have shown that when fracture stages are spaced at great intervals, reservoir drainage is relatively poor. But when fractures are more closely spaced, the reservoir recovery factor is dramatically improved. For example, in a 400 nanoDarcy shale reservoir with fracture stages spaced at 1,000 feet, the recovery factor is only about 50 percent after 60 years of continuous production. If the same reservoir was fractured with 250-foot spacing, it would be almost completely depleted after 60 years. Moreover, the 250-foot spaced fractures would drain about the same amount of gas in 10 years as the 1,000-foot spaced fractures could drain in 60 years.

Multistage fracturing technology allows stages to be closely spaced, but getting all the fractures to accept fluid has been problematic. The fluid always follows the path of least resistance, and once it opens up a fracture, it tends to follow it until screen-out. However, new degradable diversion media have allowed engineers to shift away from early fractures and open new ones, giving much better overall reservoir contact. After a few days, the diversion material in the early fractures dissolves and all the fractures are left open to produce.

This is where the real-time microseismic monitoring comes in. When engineers see a fracture developing, it can be observed, and propagation arrested after the fracture reaches optimum length by adding the degradable diversion media to the slurry. This will bridge the fracture and cause the next path of least resistance to open. Using a succession of diversion stages, the fractures can be steered to intersect the maximum amount of reservoir rock. All of the fractures created during one treatment stage are mapped using the microseismic monitoring technique, and the collective data are used to optimize the next stage until all stages have been pumped.

The degradable diversion media consists of millions of tiny fibers. In addition to helping bridge off a fracture and diverting pumping energy to another spot, the fibers also prevent proppant from “slumping” to the bottom of the fracture, thereby ensuring uniform proppant distribution across the entire fracture height.

**Barnett Shale Case Study**

Stretching across North-Central Texas, the Barnett Shale has benefited greatly from microseismic fracture monitoring. The shale play is tight with gas-filled...
porosities from 3 to 5 percent and permeability on the order of nanoDarcies. Lying just beneath the Barnett to the west is the Ellenberger carbonate, a porous, karsted limestone that is water bearing. Most of the Barnett Shale is underlain by the Viola Limestone, which provides a hydraulic seal between the deeper Ellenberger and the Barnett, but the Viola pinches out to the west of Fort Worth. As a result, for many of the western Barnett wells, there is a danger that hydraulic fractures will propagate into the Ellenberger and flood out.

Devon Energy Corporation faced the possibility of unwanted Ellenberger water in some of its Barnett Shale wells. The situation is illustrated in Figure 1, which shows a seismic map of Barnett completions with the microseismic monitor well (closure stress gradients are indicated by colored “flashing,” with red denoting high stress). Two horizontal producers, one drilled from north to south and the other drilled from west to east, bracketed a fault of the Ellenberger, labeled as a geohazard on the map. A horizontal observation well lay between the two producers. Engineers wanted to carefully observe the first-stage treatment of the west-to-east producer to ensure they did not frac down into the Ellenberger.

After an array of geophones was deployed in the observation well, treatment began using the “plug n’ perf” technique, which has enjoyed a renaissance in popularity since the advent of microseismic monitoring because the technique allows engineers to make frac design changes based on observations of each stage in the multistage treatment. Figure 2 shows a section view of the stage-one treatment.

The yellow bubbles represent the microseisms recorded during stage one, and clearly show that the fracture did not propagate into the geohazard.

As subsequent stages were treated, di-
The diverters were employed to shift the fractures into untreated volumes of the reservoir. Figure 3 shows both plan and section views of all treatment and diversion stages, with bubbles color coded to indicate the effect of the diversion media. The results show a wide dispersal of fractures, with the propagation of all subsequent fracturing staying well away from the geohazard.

Restimulation Project

In a second example, Devon planned to re-enter a producing well and restimulate it. The plan was to perforate between the previously perforated zones to improve reservoir contact and open new volumes to production. Figure 4 shows the restimulation candidate well with original perforations (black) and the original microseismic hydraulic fracture stimulation diagnostics plot, as well as the proposed locations of refrac perforations (orange).

The original well was drilled in the direction of minimum horizontal stress and cased with 5½-inch uncemented pipe. The well bore orientation favored the generation of transverse fractures, and that is what occurred when the well was initially treated in a single-stage hydraulic fracturing job. Instantaneous shut-in pressure following treatment was 2,050 psi. After about 4½ years, the well was restimulated using fiber diversion media to divert the retreatment from migrating along the casing annulus and entering the original fractures.

Using real-time microseismic monitoring in conjunction with the fiber diverters, the engineers were able to make treatment changes on the fly to improve the overall effectiveness of the stimulation. Devon was able to open several new fractures by deploying fracture diversion stages at strategic intervals during treatment. Pump pressure showed that the diverters were effectively bridging off the old fractures and creating new ones. The diverters were deployed in four stages, with deployment times guided by real-time observations from microseismic monitoring.

Figure 5 shows the result of the completed restimulation, color-coded to show the effect of the different diversion stages. A histogram illustrates how substantial new fractures were created closer to the heel of the well during the second-stage diversion.

The restimulation job was enabled by the effective use of fiber diversion media to shift stimulation energy to new areas of the reservoir. Deciding when to deploy the diverters was enabled by real-time microseismic monitoring. The combination of the two techniques resulted in a 400 percent improvement in production rate over the initial completion. The production history in Figure 6 shows the results of the successful restimulation treatment. Payout for the restimulation job was achieved in about 60 days.

According to the operator’s estimates, ultimate recovery from the well has been boosted by 20 percent by the restimulation treatment. The technique bodes well for the more than 8,000 horizontal producing wells drilled in the Barnett to date, and should work equally well in cemented completions, as well as in other shale plays worldwide.

Editor’s Note: For more detailed information on the microseismic monitoring work performed in the Devon Energy Barnett Shale wells, please see OTC 20268, a technical paper presented at the 2009 Offshore Technology Conference, held May 4-7 in Houston.

DEANE SPARKMAN is a geophysicist at Devon Energy Corporation in Oklahoma City. She has worked the Barnett Shale in the Fort Worth Basin for Devon Energy since 2005. Her work has focused on integrating seismic, seismic attributes, microseismic and production to optimize completion techniques in unconventional reservoirs. Sparkman holds a B.S. in geology and an M.S. in geophysics from the University of Oklahoma.

JAMEL BELHADI is an operations engineering adviser working for Devon Energy Corporation in Oklahoma City. His 25 years of oil field experience cover reservoir characterization and modeling, well placement and construction, horizontal completions and stimulation, real-time microseismic monitoring, production monitoring and optimization, and workover operations. In his current position, Belhadi is responsible for completion and production engineering operations in the Barnett Shale play. He holds an M.S. from the University of Southern California.

GEORGE WATERS is the North American reservoir stimulation domain manager for Schlumberger in Oklahoma City. He is responsible for developing and directing the technical strategy for the Schlumberger stimulation business in North America. Waters is a 2009-10 Society of Petroleum Engineers’ distinguished lecturer on stimulating shale reservoirs. He joined Schlumberger in 1985 and has held numerous completion engineering assignments, focusing primarily on low-permeability hydraulic fracture optimization. Since 2000, he has concentrated on evaluating and completing shale reservoirs. Waters holds a B.S. in petroleum engineering from West Virginia University, an M.S. in environmental engineering from Oklahoma State University, and an M.S. in petroleum engineering from the Institut Francais du Petrole.