The Source for Hydraulic Fracture Characterization

Improved understanding of hydraulic fracture geometry and behavior allows asset teams to increase stimulation effectiveness, well productivity and hydrocarbon recovery. Although seismic methods for characterizing hydraulic fractures have existed for years, new seismic hardware and processing techniques make this type of monitoring significantly more effective than in the past.

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Many of the world's large, high-permeability reservoirs are now approaching the end of their productive lives. Increasingly, the hydrocarbons that fuel nations and economies will come from low-permeability reservoirs, and those tight formations require hydraulic fracture stimulation to produce at economical rates.

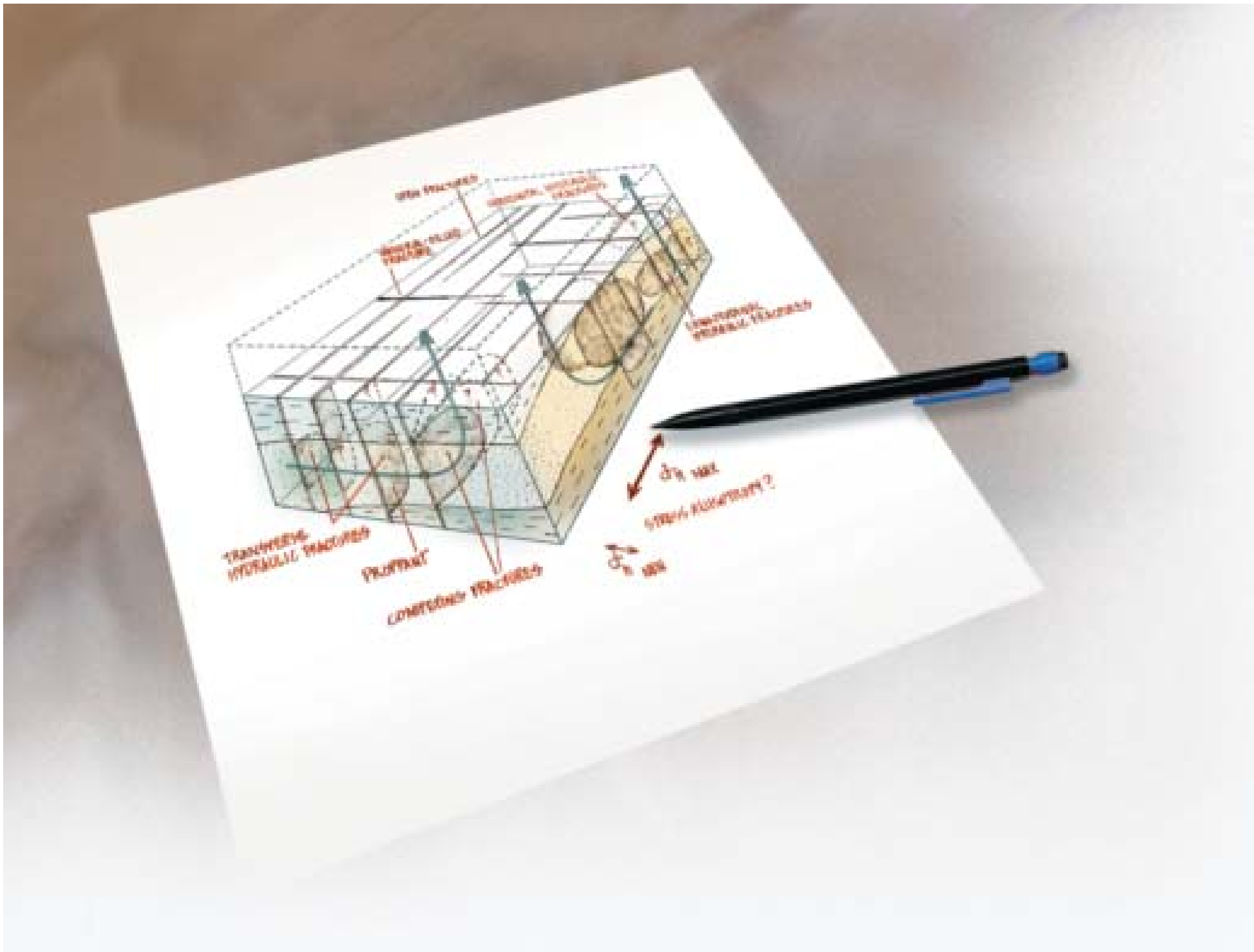
In the USA alone, operating companies spent roughly US$ 3.8 billion on hydraulic fracturing in 2005.[1] This huge expenditure is expected to increase in the near future and to spread throughout the world. Companies need tools that help them determine how successfully their hydraulic fractures have optimized well production and field development. To do this, these tools should provide information about hydraulic fracture conductivity, geometry, complexity and orientation.

While indirect well-response methods—fracture modeling using net-pressure analysis, well testing and production-data analysis—are used routinely to infer the geometry and productivity of hydraulic fractures, measurements of the formation's response to fracturing are now feasible to quantify fracture geometry, complexity and orientation.[2] This article discusses the importance of characterizing hydraulic fractures when trying to optimize production rates and hydrocarbon recovery within a field. We highlight a method of monitoring hydraulic fractures that uses seismic technologies, including data acquisition, processing and interpretation, and some associated complexities. The microseismic hydraulic fracture monitoring technique is demonstrated in case studies from the USA and Japan, featuring two different fracturing environments.

Fracture Stimulation

From the first intentional hydraulic fracture stimulation of a reservoir in the late 1940s, engineers and scientists have sought to understand the mechanics and geometry of hydraulically created fractures.[3] Although an increase in productivity or injectivity of a stimulated reservoir may imply a successful treatment, it does not necessarily mean that the reservoir and fracture models correctly predicted the outcome.

Reservoir characteristics should always be considered when designing hydraulic fracture treatments. In moderate- to high-permeability reservoirs, fractures are designed to improve production by bypassing near-wellbore formation damage.[4] In these reservoirs, the most important fracture characteristic is dimensionless fracture conductivity—a function of the width, permeability and length of the fracture and of formation-matrix permeability. In permeable but weakly consolidated reservoirs, fracturing methods are used in conjunction with gravel packing to reduce the pressure drop and fluid velocities around a wellbore during production, and therefore mitigate sand production.[5]



In low-permeability reservoirs, by far the most common reservoir type to be fracture stimulated, industry experts have established that fracture length is the overriding factor for increased productivity and recovery.[6] From a reservoir-development standpoint, having a reasonable understanding of hydraulic fracture geometry and orientation is crucial for determining well spacing and for devising field-development strategies designed to extract more hydrocarbons.[7] Reservoir modeling is also enhanced with improved knowledge of hydraulic fractures within a field.[8]

Natural fractures, often the primary mechanism for fluid flow in low-permeability reservoirs, severely compromise the ability to predict the geometry of hydraulic fractures and the stimulation's effect on production and drainage. Understanding how hydraulically created fractures interact with natural fracture systems—open and mineral-filled—requires knowledge of both hydraulic and natural fracture types.

Hydraulic fractures tend to propagate according to the present-day stress directions and preexisting planes of weakness, such as natural fractures. The orientations of natural fracture systems reflect ancient and possibly localized stress regimes.

In low-permeability reservoirs, the combined effects of natural and hydraulic fractures are largely responsible for improved productivity from horizontal wells as compared with the production from vertical wells.[9] The characteristics of both fracture types dictate the

1. Spears R: "Oilfield Market Report 2005," Spears & Associates, Inc., http://www.spearsresearch.com/ (accessed on October 14, 2005).
2. Barree RD, Fisher MK and Woodroof RA: "A Practical Guide to Hydraulic Fracture Diagnostic Technologies," paper SPE 77442, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002.

   Cipolla CL and Wright CA: "Diagnostic Techniques to Understand Hydraulic Fracturing: What? Why? and How?" paper SPE 59735, presented at the SPE/CERI Gas Technology Symposium, Calgary, April 3–5, 2000.
3. Brady B, Elbel J, Mack M, Morales H, Nolte K and Poe B: "Cracking Rock: Progress in Fracture Treatment Design," *Oilfield Review* 4, no. 4 (October 1992): 4–17.
4. Meng HZ: "Design of Propped Fracture Treatments," in Economides MJ and Nolte KG (eds): *Reservoir Stimulation*. Schlumberger Educational Services: Houston, 1987.
5. Ali S, Norman D, Wagner D, Ayoub J, Desroches J, Morales H, Price P, Shepherd D, Toffanin E, Troncoso J and White S: "Combined Stimulation and Sand Control," *Oilfield Review* 14, no. 2 (Summer 2002): 30–47.
6. Meng, reference 4.
7. Peterman F, McCarley DL, Tanner KV, Le Calvez JH, Grant WD, Hals CF, Bennett L and Palacio JC: "Hydraulic Fracture Monitoring as a Tool to Improve Reservoir Management," paper SPE 94048, presented at the SPE Production Operations Symposium, Oklahoma City, Oklahoma, April 16–19, 2005.
8. Aly AM, El-Banbi AH, Holditch SA, Wahdan M, Salah N, Aly NM and Boerrigter P: "Optimization of Gas Condensate Reservoir Development by Coupling Reservoir Modeling and Hydraulic Fracturing Design," paper SPE 68175, presented at the SPE Middle East Oil Show and Conference, Bahrain, March 17–20, 2001.
9. Hashemi A and Gringarten AC: "Comparison of Well Productivity Between Vertical, Horizontal and Hydraulically Fractured Wells in Gas-Condensate Reservoirs," paper SPE 94178, presented at the SPE Europec/EAGE Annual Conference, Madrid, Spain, June 13–16, 2005.

preferred azimuth in which highly deviated and horizontal wells should be drilled. Theoretically, in a horizontal well drilled parallel to the maximum horizontal stress direction, hydraulic stimulation produces a single longitudinal fracture along the horizontal wellbore. This scenario simplifies fluid flow out of the wellbore during stimulation and into the wellbore during production. However, depending on the characteristics and orientations of the natural fracture systems, a transverse hydraulic fracturing strategy may actually result in higher productivity, especially when multiple zones are being stimulated.[10]

While it is possible to have a good understanding of existing natural fracture systems, our ability to determine hydraulic fracture geometry and characteristics has been limited. Geologic discontinuities such as fractures and faults can dominate fracture geometry in a way that makes predicting hydraulic fracture behavior difficult. Clearly, the exploration and production (E&P) industry still has much to learn about hydraulic fractures.

Characterization of the Complex

More than simple curiosity drives petroleum industry engineers and scientists to seek understanding of hydraulic fractures. Fracture stimulation is an expensive process, which can reap huge returns if done correctly. Yet to comprehend hydraulic fracture propagation, accurate measurements of fracture growth, geometry and orientation are needed. These data provide a starting point for asset teams to assess post-stimulation production performance and optimize future stimulation treatments—to lower the cost or increase the effectiveness of stimulation or both. This information can then be used to drive reservoir-development strategies.

Fractures from both horizontal and vertical wells can propagate vertically out of the intended zone, reducing stimulation effectiveness, wasting horsepower, proppant and fluids, and potentially connecting up with other hydraulic fracturing stages or unwanted water or gas intervals. The direction of lateral propagation is largely dictated by the horizontal stress regime, but in areas where there is low horizontal stress anisotropy or in reservoirs that are naturally fractured, fracture growth can be difficult to model. In shallow zones, horizontal hydraulic fractures can develop because the vertical stress component—the overburden weight—is smallest. A horizontal hydraulic fracture reduces the effectiveness of the stimulation treatment because it most likely forms along horizontal planes of weakness—presumably between formation beds—and is aligned preferentially to formation vertical permeability, which is typically much lower than horizontal permeability.

After a hydraulic fracture is initiated, the degree to which it grows laterally or vertically depends on numerous factors, such as confining stress, fluid leakoff from the fracture, fluid viscosity, fracture toughness and the number of natural fractures in the reservoir.[11] All hydraulic fracture models fail to predict fracture behavior precisely, and in many cases, models fail completely, largely because of incorrect information and assumptions used in the models. Nevertheless, modeling is a necessary tool in fracture engineering.

Stimulation engineers use hydraulic fracture simulators to design and predict optimal fracture stimulation treatments. Basic inputs to these models include fluid and proppant properties and volumes, closure stress, pore pressure, formation permeability and mechanical rock properties, such as Poisson's ratio and Young's modulus. The risk of an inadequate treatment occurring is increased by estimating these inputs. Asset teams can take steps to reduce this risk by using better models and by more thoroughly characterizing the reservoir and associated stresses. These steps may include acquiring petrophysical and mechanical properties from logs, obtaining borehole stress and natural fracture information from borehole images, and directly measuring the stresses by performing the DataFRAC fracture data determination service.

Fracture modeling is a necessary part of the stimulation design and improvement process. However, even the most complex models fall short in predicting reality.[12] In the last 15 years or so, the industry has learned that hydraulic fractures are much more complex than the biwing, single-plane cracks depicted in models. Investigation of actual hydraulic fracture geometries, from minebacks, core-throughs and thousands of mapped fractures, has shown an almost limitless range of complexities, starting with fracture asymmetry and the creation of multiple competing fractures.[13]

Given the complexities introduced by the presence of natural fracture systems, reservoir heterogeneity and stress anisotropy, there is little reason to believe that a hydraulically induced fracture would maintain symmetry as it propagates outward from the borehole. Asymmetrical hydraulic fractures form asymmetrical drainage patterns that should be considered when planning development drilling and modeling fluid flow within the reservoir. In addition, unexpected hydraulic fracture behavior can occur in depleted reservoirs or during refracturing operations.[14]

Assess and Monitor

Various methods are available to assess hydraulic fracture geometry before, during and after fracture creation (next page).[15] The accuracy of indirect well-response techniques is linked to the accuracy of the fracture and reservoir models that generate the prediction. By far the most common way to judge how well the treatment was delivered and its resulting geometry is to perform a net-pressure fracture analysis shortly after, or even during, the fracture treatment. The result of this analysis is closely linked to treating pressure and therefore suffers when actual bottomhole pressure data are not available. Unfortunately, on a large percentage of jobs, treating pressure is measured at the surface—corrected for hydrostatic head and pipe friction. A more accurate treating pressure is measured downhole, but even accurate treating pressure data do not necessarily reflect fracture geometry.[16]

Another indirect way to deduce the geometry of hydraulic fractures uses post-treatment production data. This method determines the well productivity and is represented as an effective fracture geometry that reflects the portion of the hydraulic fracture that is open, cleaned up and contributing to production. It may require months to years of production history to

10. Brown E, Thomas R and Milne A: "The Challenge of Completing and Stimulating Horizontal Wells," *Oilfield Review* 2, no. 3 (July 1990): 52–63.
11. Fracture propagation occurs when the stress-intensity factor exceeds the degree of fracture toughness near the fracture tip. Fracture toughness, or the critical stress-intensity factor, can be measured by performing core burst tests in the laboratory.
12. Barree et al, reference 2.
Wright CA, Weijers L, Davis EJ and Mayerhofer M: "Understanding Hydraulic Fracture Growth: Tricky but Not Hopeless," paper SPE 56724, presented at the SPE Annual Technical Conference and Exhibition, Houston, October 3–6, 1999.
13. Peterson RE, Warpinski NR, Lorenz JC, Garber M, Wolhart SL and Steiger RP: "Assessment of the Mounds Drill Cuttings Injection Disposal Domain," paper SPE 71378, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 3, 2001.
Jeffery RG, Settari A and Smith NP: "A Comparison of Hydraulic Fracture Field Experiments, Including Mineback Geometry Data, with Numerical Fracture Model Simulations," paper SPE 30508, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 22–25, 1995.
14. Dozier G, Elbel J, Fielder E, Hoover R, Lemp S, Reeves S, Siebrits E, Wisler D and Wolhart S: "Refracturing Works," *Oilfield Review* 15, no. 3 (Autumn 2003): 38–53.
15. Cipolla and Wright, reference 2.
16. Barree et al, reference 2.

Capabilities and Limitations of Fracture Diagnostics

Techniques: can determine / may determine / cannot determine

Group	Fracture Diagnostic Method	Main Limitations	Ability to Estimate: Length	Height	Asymmetry	Width	Azimuth	Dip	Volume	Conductivity
Far field, during fracturing	Surface tiltmeter mapping	• Cannot resolve individual and complex fracture dimensions • Mapping resolution decreases with depth (fracture azimuth ±3° at 3,000-ft depth and ±10° at 10,000-ft depth)	may determine	may determine	may determine		can determine	can determine	can determine	
Far field, during fracturing	Downhole tiltmeter mapping	• Resolution in fracture length and height decreases as monitoring-well distance increases • Limited by the availability of potential monitoring wells • No information about proppant distribution and effective fracture geometry	can determine	can determine	can determine	may determine	may determine		can determine	
Far field, during fracturing	Microseismic mapping	• Limited by the availability of potential monitoring wells • Dependent on velocity-model correctness • No information about proppant distribution and effective fracture geometry	can determine	can determine	can determine		can determine	may determine		
Near wellbore, after fracturing	Radioactive tracers	• Measurement in near-wellbore volume • Provides only a lower limit for fracture height if fracture and well path are not aligned		may determine		may determine	may determine			
Near wellbore, after fracturing	Temperature logging	• Thermal conductivity of different formations can vary, skewing temperature log results • Post-treatment log requires multiple passes within 24 h after the treatment • Provides only a lower limit for fracture height if fracture and well path are not aligned		may determine						
Near wellbore, after fracturing	Production logging	• Provides only information about zones or perforations contributing to production in cased-hole applications		may determine						
Near wellbore, after fracturing	Borehole image logging	• Run only in open hole • Provides fracture orientation only near the wellbore		may determine		may determine	may determine	may determine		
Near wellbore, after fracturing	Downhole video	• Run mostly in cased holes and provides information only about zones and perforations contributing to production • May have openhole applications		may determine						
Model based	Net-pressure fracture analysis	• Results depend on model assumptions and reservoir description • Requires "calibration" with direct observations	may determine	may determine		may determine			may determine	may determine
Model based	Well testing	• Results dependent on model assumptions • Requires accurate permeability and reservoir pressure estimates	may determine			may determine				may determine
Model based	Production analysis	• Results dependent on model assumptions • Requires accurate permeability and reservoir pressure estimates	may determine			may determine				may determine

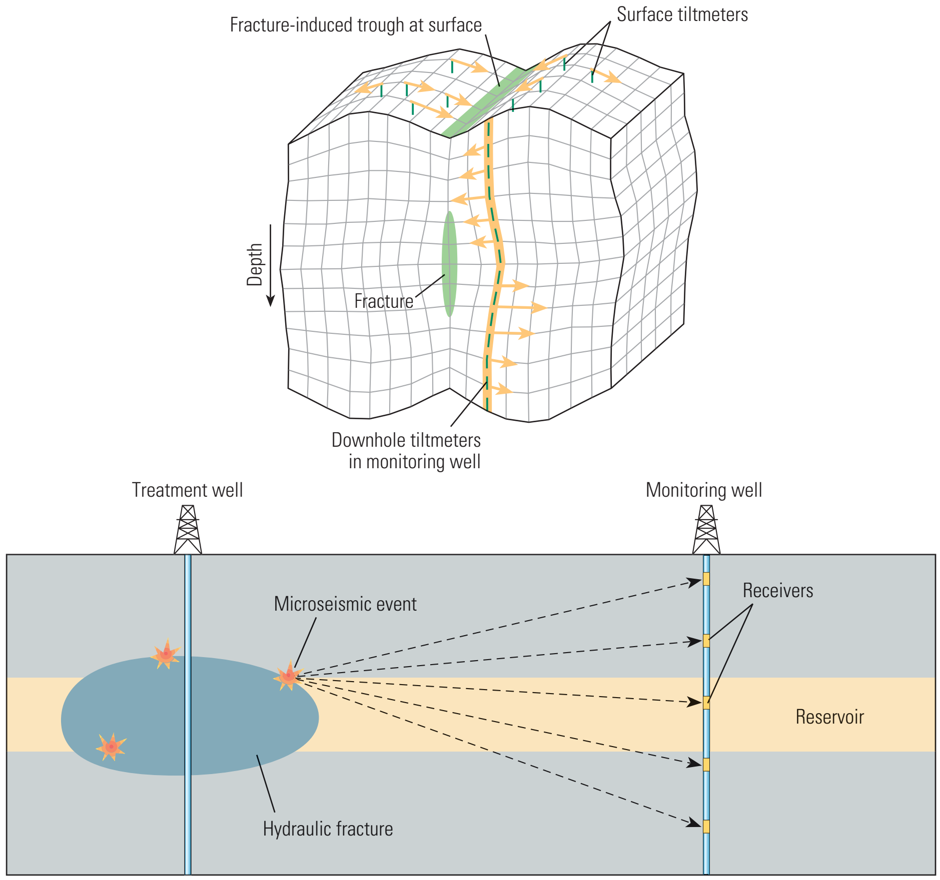
^ Capabilities and limitations of indirect and direct hydraulic fracture diagnosis techniques. (Adapted from Cipolla and Wright, reference 2.)

perform the analysis, and the fracture geometry that has been cleaned up may be vastly different from the fracture geometry created hydraulically. The effective producing geometry is important for production estimation, but will, in general, underestimate the hydraulic fracture length.

Similar to the production analysis method, estimating fracture geometry from well testing methods—buildup and drawdown—better defines the effective production geometry than what has been created hydraulically.

Near-wellbore methods have been used to investigate the presence of hydraulic fractures. These include radioactive tracers, and temperature and production logs. While these techniques are widely used to detect the presence of hydraulic fractures and estimate fracture height, their limitation is that they measure in a region that is at or near the wellbore and may not be representative of what is occurring away from the borehole.

Advances in radioactive isotope tagging during injection and in the interpretation methods that use hundreds of spectral channels allow stimulation engineers to better discern fluid and proppant placement during multiple-stage stimulation treatments. Temperature surveys run after stimulation treatments identify near-wellbore regions that have been cooled by the injection of fracturing fluids and therefore provide an estimate of fracture height. Production logs—measurements such as fluid flow, fluid density and temperature—are used to identify perforation intervals that are open and contributing to flowback or production. A positive flow response from a perforated interval



^ Tiltmeter and microseismic methods of far-field fracture monitoring. Tiltmeters (*top*) measure small changes in earth tilt. When these are mapped they show the deformation in response to the creation of hydraulic fractures. Tiltmeters can be deployed on surface or downhole in a monitoring wellbore. Microseismic monitoring (*bottom*) uses sensitive, multicomponent sensors in monitoring wells to record microseismic events, or acoustic emissions (AEs), caused by rock shearing during hydraulic fracture treatments. The microseismic data are then processed to determine the distance and azimuth from the receiver to the AE and the depth of the AE.

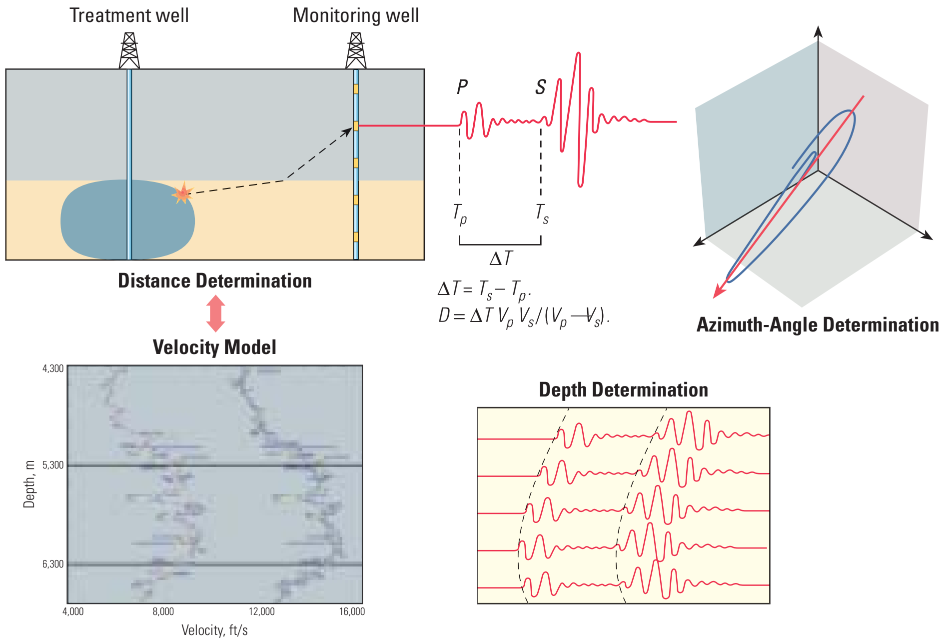
suggests that the zone has been stimulated, especially if it compares favorably with a pretreatment logging pass. However, flow into the wellbore from a set of perforations may not mean that a specific interval has been treated more effectively because reservoir fluids can flow through communicating hydraulic fractures from one zone to the next.

In an effort to better characterize hydraulic fracture behavior and geometry away from the wellbore, two HFM Hydraulic Fracture Monitoring techniques have proved enormously successful. These far-field fracture-mapping methods are surface and downhole tiltmeters and microseismic monitoring (above). Available for more than a decade, tiltmeters measure hydraulic fracture-induced tilt, or deformation. By placing these devices in an array of shallow boreholes—20 to 40 ft [6 to 12 m] deep—deformation induced by fracture creation is measured. A map of deformation at the surface can be constructed from these surface data, allowing estimation of the azimuth, dip, depth and width of the hydraulic fracture.

Downhole tiltmeters are deployed in nearby monitoring wells at a depth similar to that of the created fracture. Because this technique allows the sensors to be placed much closer to a propagating fracture than the surface method, the fracture geometry measurements tend to be more accurate and include fracture azimuth, height, length and width.[17] The success of tiltmeter methods usually depends on the spatial relationship between the tiltmeters—surface or downhole—and the treatment well.

Mapping with surface tiltmeters has limitations when attempting to characterize hydraulic fractures deeper than 10,000 ft [3,050 m]. As a general rule, downhole tiltmeters lose their effectiveness when the distance from the hydraulic fracture to the tiltmeter exceeds three times the length of the created fracture. Another method, first investigated in 1982, monitors far-field fracture growth and geometry using sensitive seismic receivers, such as the Schlumberger VSI Versatile Seismic Imager tool, deployed in nearby wells to detect microseismic events.[18]

17. Barree et al, reference 2.
Cipolla and Wright, reference 2.
18. Albright JN and Pearson CF: "Acoustic Emissions as a Tool for Hydraulic Fracture Location: Experience at the Fenton Hill Hot Dry Rock Site," *SPE Journal* 22 (August 1982): 523–530.
19. Arroyo JL, Breton P, Dijkerman H, Dingwall S, Guerra R, Hope R, Hornby B, Williams M, Jimenez RR, Lastennet T, Tulett J, Leaney S, Lim T, Menkiti H, Puech J-C, Tcherkashnev S, Burg TT and Verliac M: "Superior Seismic Data from the Borehole," *Oilfield Review* 15, no. 1 (Spring 2003): 2–23.
20. Warpinski NR, Wolhart SL and Wright CA: "Analysis and Prediction of Microseismicity Induced by Hydraulic Fracturing," paper SPE 71649, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 3, 2001.



^ Locating acoustic emissions. The distance (D) to the event can be derived by measuring the difference (ΔT) between the compressional, or primary (P-) wave and the shear, or secondary (S-) wave arrival times, T_p and T_s, respectively (*top left*). The value D is heavily dependent on the velocity model (*bottom left*), which is usually described by the P- and S-wave velocities, V_p and V_s, respectively, of each layer in the model. The second coordinate, azimuth to the microseismic event, is determined by examining the particle motion of the P-waves using hodograms (*top right*). The depth of the microseismic event, the third coordinate, is derived by examining the P- and S-wave arrival delays between receivers, or moveout, at the monitoring well (*bottom right*).

Tracking the Cracking

Microseismic events, or small earthquakes, occur when the normal stress is reduced along preexisting planes of weakness until shear slippage occurs. These shear movements emit both compressional and shear waves that can be detected by geophones. However, many believe the tensile cracking of rock that occurs during fracture stimulation has a minimal contribution to detectable microseismic activity. Because this zone of shearing accompanies the fracture tip area, locating the source of these waves in space and time allows scientists and engineers to construct a map of the created fracture by plotting the location of acoustic emissions (AEs) over time while fracturing. However, AEs may also occur away from the fracture tip where there is fluid leakoff into the matrix or where stress changes cause shear slippage in natural fractures.

To record compressional and shear waves, multicomponent—for example, three-component (3C)—geophones are placed in a monitoring well to determine the location of microseismic events. The distance to the event can be calculated by measuring the difference in arrival times between the compressional, or primary (P-) waves, and shear, or secondary (S-) waves. Also, hodogram analysis, which examines the particle motion of the P-waves, may determine the azimuth angle to the event. The depth of the event is constrained by using the P- and S-wave arrival delays between receivers observed at the monitoring well (above). This localization technique requires an accurate velocity model from which to calculate event locations, a low-noise environment, highly sensitive geophones to record microseismic events and knowledge of the exact location and orientation of the receivers. Although this may seem simple, the process is complex and challenging.

The quality of hydraulic fracture characterization is directly linked to the quality of the velocity model, or velocity structure, on which the interpretation is based. Initial velocity models typically are built using borehole sonic logs that describe the vertical velocity changes at wellbores. However, the time it takes for an AE to go from the source—near the hydraulic fracture—to the receiver and the direction from which it comes into the receiver are influenced by the interwell geology. Borehole seismic measurements, such as vertical seismic profiles (VSPs), provide detailed velocity information around the monitoring well. VSP surveys help relate the time domain to the depth domain and therefore help calibrate the velocity model. The VSI tool used to acquire the VSP data also records the microseismic events, ensuring consistency in data acquisition, processing and interpretation.[19]

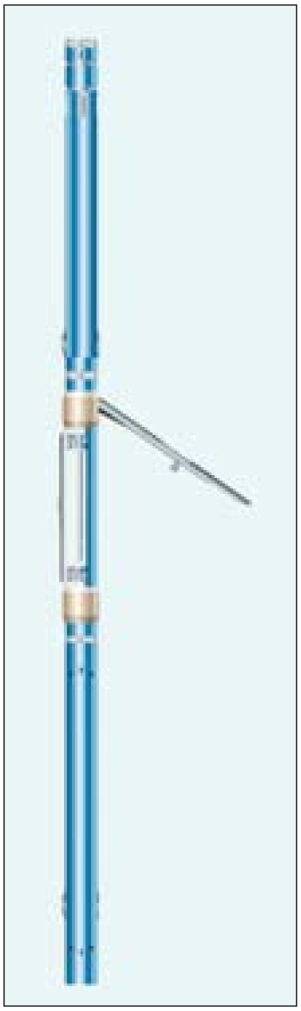
Reservoir-fluid type may also impact microseismic activity. Fluid factors can reduce stress and pore-pressure changes in the formation that occur during fracturing. Having gas in the formation instead of less compressible liquids decreases the area of microseismic activity. Consequently, some in the industry believe that gas-filled reservoirs produce a narrower band of microseismic events that more clearly defines the geometry of the fracture.[20]

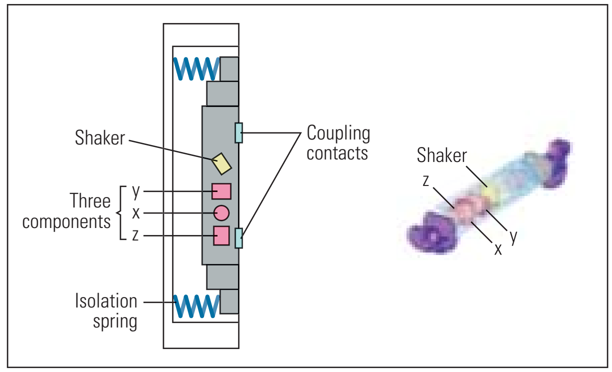
To locate AEs, a monitoring tool—typically an array of eight 3C geophones for the VSI tool—is deployed in a monitoring well within 2,000 ft [610 m] of the treatment well at roughly the same depth as the treatment interval. The optimal placement and geometry of the microseismic tool within the monitoring well are heavily dependent on the surrounding velocity structure, so accurate earth models help optimize the monitoring configuration.[21] Unfortunately, the ideal spatial configuration between the treatment wellbore and potential monitoring wellbores occurs in only a small percentage of cases. Consequently, there is an ongoing effort to enable the recording of AEs from treatment wells—a harsh and noisy environment.

Producing oil fields have many sources of noise that may have a negative impact on the microseismic HFM technique, including electrical noise, nearby drilling activity and hydraulic fracturing jobs or fluid flowing from perforations in the monitoring well. Much of the noise can be eliminated on site or through adaptive filtering during data processing. Improved seismic response can also be achieved through advances in acquisition technology.

For example, the Schlumberger microseismic HFM technique uses the VSI device, which provides excellent vector fidelity (right).[22] The VSI tool is deployed on wireline cable and uses three-axis technology in each sensor package, or shuttle; eight sensor packages are typically deployed. The tool's sensors were designed to be acoustically isolated from the main body of the tool but acoustically coupled to the casing during the HFM operation. This helps minimize the potential for noise and maximize data quality when recording very small microseismic events. The number of sensor sections and their spacing within the VSI configuration can be adjusted, depending on what is required.[23]

Optimal positioning of the sensor array should be determined using network survey-design techniques.[24] Once the VSI tool is set at the appropriate depth in a monitoring well, the HFM engineer must determine the orientation of the tool to make use of particle-motion data for determining the azimuth angle. This is accomplished by monitoring a perforation shot, string shot or other seismic source in the treatment well, or in another well near the treatment well.[25] The utility of perforations or string shots to calibrate velocity models has been documented.[26] However, shot-based velocities are often substantially different—sometimes higher, sometimes lower—than velocities calculated from sonic data. These differences may be due to perforation-timing problems, imprecise locations of perforations and receivers because of inaccurate or nonexistent wellbore-deviation surveys, reservoir heterogeneity between the treatment and monitor wells, and inherent differences between the velocity measurements being compared—including anisotropy and invasion effects.[27]



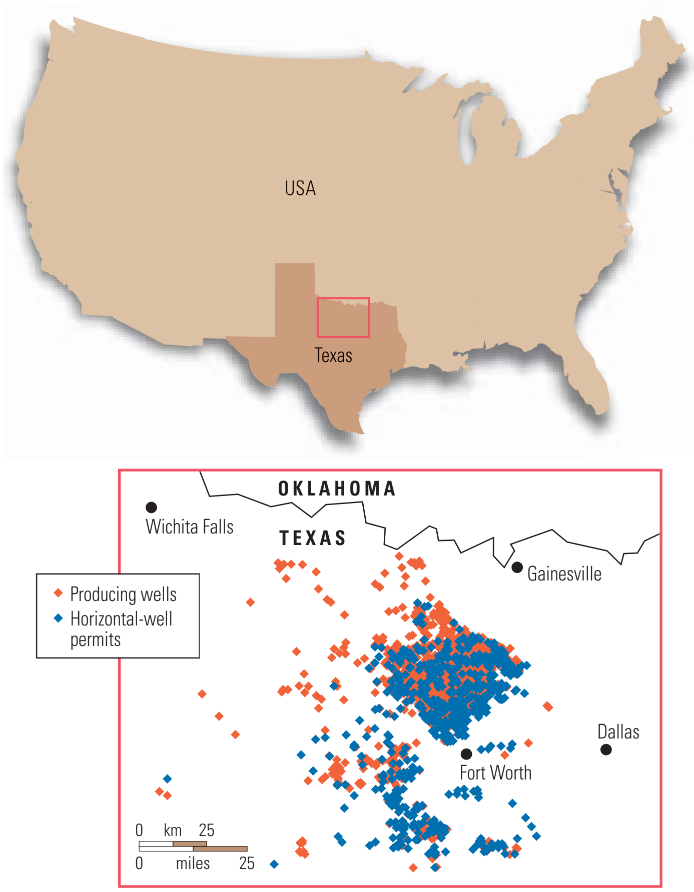


^ Measuring acoustic emissions. The Schlumberger VSI Versatile Seismic Imager tool (*left*) uses three-axis (x, y, z) geophone accelerometers (*right*) that are acoustically isolated from the tool body by an isolation string to acquire high-fidelity seismic data. The VSI device is mechanically coupled to the casing or formation by a powerful anchoring arm. The coupling quality can be tested by using an internal shaker before operations commence. Up to 40 sensor packages, or shuttles, can be linked together to increase vertical coverage; however, eight shuttles are normally used in HFM operations. The tool is available in 3.375-in. and 2.5-in. diameters.

With the tool orientation determined, the surface equipment is set up for continuous monitoring, and when an event is detected, buffered data are recorded. On-site processing locates the microseismic events, using one of several available processing techniques, and the results are transmitted to the fracturing operations team at the treatment well location. The data are also sent to a processing center for more detailed interpretation.[28]

Texas Proving Ground

In the mining, waste disposal, geothermal and gas-storage industries, microseismic methods have long been used to help understand the nature of hydraulically created fractures. However, recent improvements in tool design, processing and mapping accuracy, coupled with the growing importance of low-permeability, hydraulically fractured reservoirs as a resource, have increased this technology's utility in the oil and gas industry. The Barnett Shale reservoir in the north-central Texas Fort Worth basin—one of today's most active gas plays in the USA—highlights the importance of direct and timely microseismic hydraulic fracture characterization.[29] Today, Barnett Shale fields produce



^ Map of the north-central Texas Fort Worth basin showing Barnett Shale activity. There are currently more than 3,400 vertical and 300 horizontal wells producing from the Barnett Shale reservoir.

more than 1,200 million ft^3/d [34 million m^3/d], 58% of the total gas production from US gas shales (left).[30]

The Barnett Shale formation is a naturally fractured, ultralow-permeability—about 0.0002 mD—reservoir. Because of this extremely low permeability, a large hydraulic fracture surface area is required to effectively stimulate the reservoir. Consequently, large volumes of fluid are pumped at high rates during stimulation treatments.

The Barnett Shale is a Mississippian-age, organic-rich, marine-shelf shale deposit that contains fine-grained, nonsiliciclastic material. This formation overlies a major unconformity surface that truncates the Ordovician-age rocks below. Throughout much of the productive area, the Viola limestone creates a lower barrier to hydraulic fracturing and separates the underlying, water-bearing Ellenberger formation from the Barnett Shale. Hydraulic fractures that break through the Viola limestone typically result in unwanted water production and decreased gas production.

Stimulation of the Barnett Shale has had variable effectiveness for reasons that are poorly understood. The companies initially operating in the Barnett Shale soon observed that this reservoir did not respond to stimulation in the same way as conventional gas reservoirs. Unusual post-treatment occurrences in which neighboring wells watered out indicated extremely long hydraulic fracture growth, often in unexpected directions from treatment wells. Modern hydraulic fracture monitoring methods, most notably microseismic monitoring, have shown that Barnett Shale stimulation and development are complicated by natural fractures and faults, which drastically influence hydraulic fracture behavior along with reservoir productivity and drainage. Moreover, the stress anisotropy in the Barnett Shale is low, so attempts to model hydraulic fracture behavior and geometry as simple, single-plane events have been ineffective.

In the last five years, engineers and scientists have learned more about the natural and hydraulic fracture systems in the Barnett Shale formation. With that knowledge, they have adapted drilling strategies to improve gas production and recovery.[31] One of these strategies is the incorporation of horizontal wells. While approximately twice as expensive as a vertical well, horizontal wells typically generate estimated ultimate recoveries that are three times greater than those of vertical wells.

21. Le Calvez JH, Bennett L, Tanner KV, Grant WD, Nutt L, Jochen V, Underhill W and Drew J: "Monitoring Microseismic Fracture Development to Optimize Stimulation and Production in Aging Fields," *The Leading Edge* 24, no. 1 (January 2005): 72–75.
22. Vector fidelity is the property of multicomponent seismic receivers to respond correctly to an impulse. A correct response occurs when a given impulse applied parallel to one of the three components registers only on that component and when applied parallel to each component individually registers the same magnitude on each of the three components. The motion that is detected by multicomponent seismic receivers ideally is the same as the original impulse.

    Nutt L, Menkiti H and Underhill B: "Advancing the VSP Envelope," *Hart's E&P* 77, no. 10 (October 2004): 51–52.
23. Nutt et al, reference 22.
24. Curtis A, Michelini A, Leslie D and Lomax A: "A Deterministic Algorithm for Experimental Design Applied to Tomographic and Microseismic Monitoring Surveys," *Geophysical Journal International* 157, no. 2 (May 2004): 595–606.
25. A string shot is made up of Primacord detonating cord fired at strategic locations, for example near the treatment depth, to transmit a seismic wave without creating a hole in the casing.
26. Warpinski NR, Sullivan RB, Uhl JE, Waltman CK and Machovoe SR: "Improved Microseismic Fracture Mapping Using Perforation Timing Measurements for Velocity Calibration," paper SPE 84488, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 5–8, 2003.
27. Eisner L and Bulant P: "Borehole Deviation Surveys Are Necessary for Hydraulic Fracture Monitoring," prepared for presentation at the 86th EAGE Conference and Exhibition, Vienna, Austria, June 12–15, 2006.
28. Durham LS: "Fracture 'Groans' Quietly Noisy: Microseismic Detection Emerging," *AAPG Explorer* 25, no. 12 (December 2004): 16–18.
29. Frantz JH, Williamson JR, Sawyer WK, Johnston D, Waters G, Moore LP, MacDonald RJ, Pearcy M, Ganpule SV and March KS: "Evaluating Barnett Shale Production Performance Using an Integrated Approach," paper SPE 96917, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.

    Maxwell SC, Urbancic TI, Steinsberger N and Zinno R: "Microseismic Imaging of Hydraulic Fracture Complexity in the Barnett Shale," paper SPE 77440, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002.

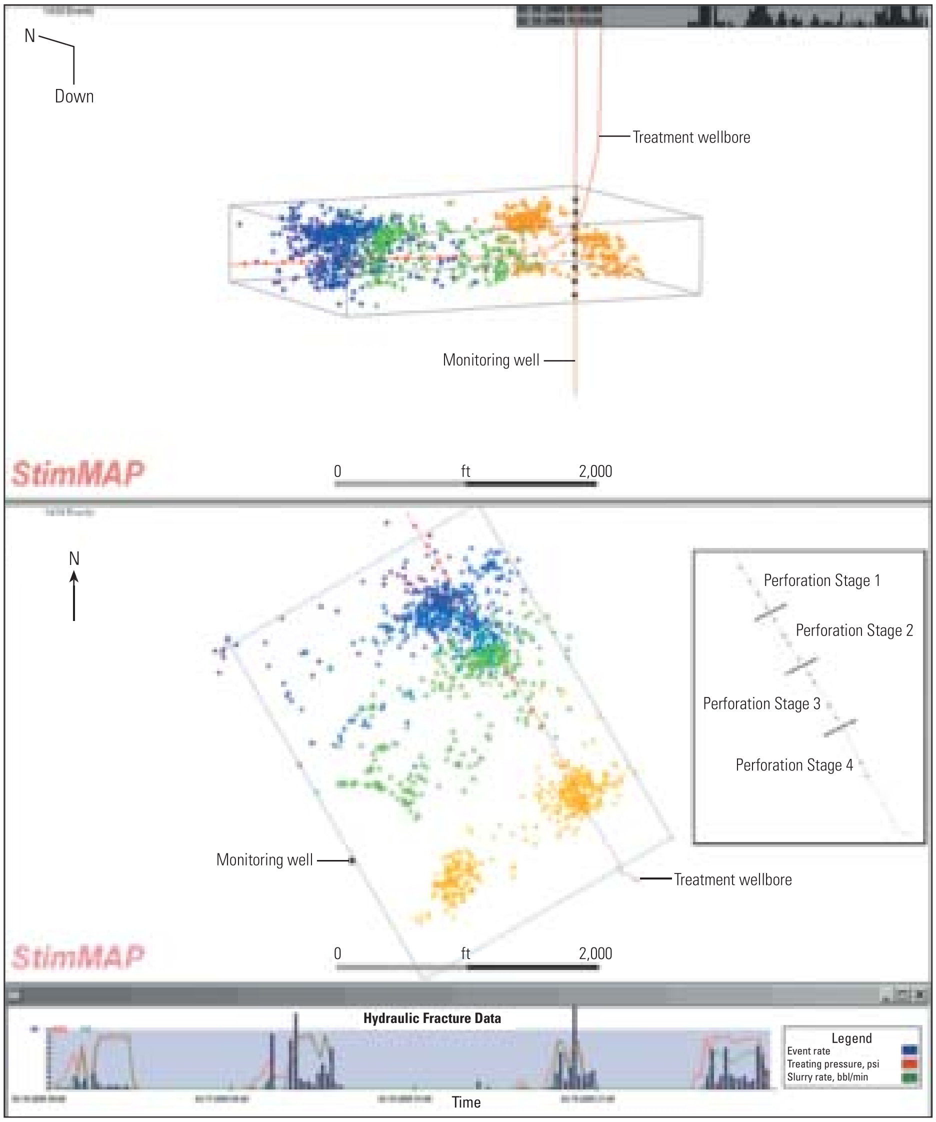
    Fisher MK, Wright CA, Davidson BM, Goodwin AK, Fielder EO, Buckler WS and Steinsberger NP: "Integrating Fracture Mapping Technologies to Optimize Stimulations in the Barnett Shale," paper SPE 77441, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002.
30. http://www.pickeringenergy.com/pdfs/TheBarnettShaleReport.pdf (accessed November 30, 2005).
31. Fisher MK, Heinze JR, Harris CD, Davidson BM, Wright CA and Dunn KP: "Optimizing Horizontal Completion Techniques in the Barnett Shale Using Microseismic Fracture Mapping," paper SPE 90051, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.

They have also been instrumental in opening up areas of the play where vertical wells have had limited success: in areas where the Viola limestone is absent and fracturing down into the wet Ellenberger is common. Optimum completion design in these wells is made more problematic because of the complex nature of the hydraulic fracturing. Factors such as perforation-cluster spacing along laterals, stimulation staging strategies, fracture treatment sizing and offset-well placement all must be addressed to optimize resource development.

Chesapeake Energy is one of several operators investigating the complexity of fracturing the Barnett Shale from horizontal wellbores and its implications for acreage development. In February 2005, Chesapeake used the StimMAP hydraulic fracture stimulation diagnostics service in a vertical monitoring well to determine fracture height, length, azimuth and complexity during a four-stage "slickwater" stimulation treatment on a horizontal well in the Newark East field.[32] The design objective was to place hydraulic fractures normal, or transverse, to the lateral. After perforating for each stage, a pretreatment injection test was performed to determine closure pressure and the rate of pressure decline, which is a function of the degree of natural fracturing because the matrix permeability is too low to allow leakoff.

During all four stages, the primary fracture propagation azimuth determined from microseismic monitoring was N60°E-S60°W, with an observed preference for southwesterly growth (below and left). Most of the detected microseismic emissions were located to the southwest because of the monitoring configuration—bias existed because the monitoring well was positioned approximately 2,000 ft to the southwest of the horizontal treatment wellbore. In this case, formation heterogeneities were unlikely to be the cause of the southwesterly bias. Chesapeake was able to observe cross-stage communication along the lateral between Stages 1 and 2 and between Stages 2 and 3, which reduced the effectiveness of those treatments.

32. Slickwater treatments use low proppant concentrations—in this case, less than 0.8 lbm/gal US [9.6 kg/m^3]—allowing high-volume treatments at reduced cost. This type of treatment has been successful in the Barnett Shale because it creates long fractures that connect with crosscutting natural fractures, thereby increasing the total effective hydraulic fracture length and drainage area in a single well.



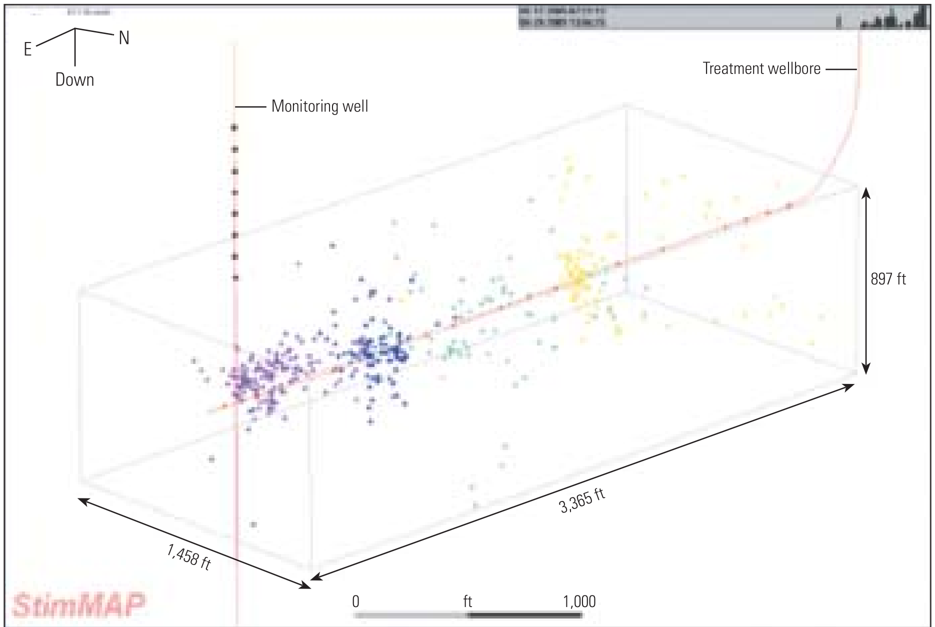
Well	Number of events	Perforated interval top, MD from KB, ft	Perforated interval bottom, MD from KB, ft	Fracture system top, TVD from KB, ft	Fracture system bottom, TVD from KB, ft	Fracture system height, ft	SW extent, ft	NE extent, ft	Fracture system length, ft	Fracture system width, ft	Azimuth
Stage 1	91	Z,360	Z,853	X,797	Y,290	493	1,918	299	2,217	1,143	N60°E
Stage 2	517	Y,740	Z,227	X,734	Y,305	571	1,728	409	2,137	2,275	N60°E
Stage 3	369	Y,025	Y,588	X,784	Y,305	521	1,556	482	2,038	1,138	N60°E
Stage 4	444	X,358	X,513	X,740	Y,309	569	1,521	424	1,945	527	N60°E

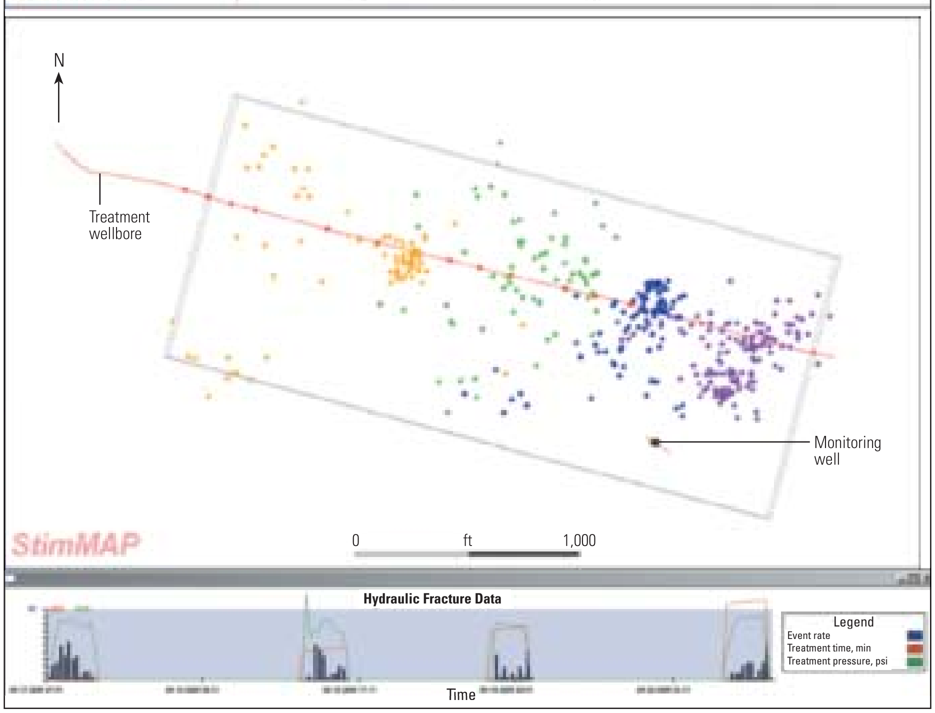
^ Maps of microseismic events from the four-stage hydraulic fracture stimulation. The StimMAP displays include a three-dimensional (3D) view (*top*) and a plan view (*middle*). The treatment stages are color-coded: Stage 1 is purple, Stage 2 is blue, Stage 3 is green, and Stage 4 is yellow. Also included is a summary of each stage, including acoustically determined fracture system length, width and preferential azimuth (*bottom*). Depths are given relative to the kelly bushing (KB).

During Stage 2, engineers on location observed that the bottomhole treating pressures matched those of Stage 1, so Chesapeake asked the Schlumberger engineer to produce a quick snapshot of the Stage 2 microseismic event locations. When compared to the Stage 1 StimMAP results, the snapshot confirmed that the Stage 2 fracture was communicating with the previous stage. To remedy this, three slugs of proppant sand were pumped at a reduced rate to divert the treatment fluid away from the perforations that were taking the majority of the treatment. Microseismic data confirmed that the treatment had communicated with a complex set of parallel and conjugate natural fractures.

The Stage 3 perforation intervals were altered to avoid a fault. Hydraulic fracture monitoring confirmed that two primary fractures were created on each side of the fault and were possibly also affected by the presence of natural fractures. Stage 4 did not appear to overlap with other stages.

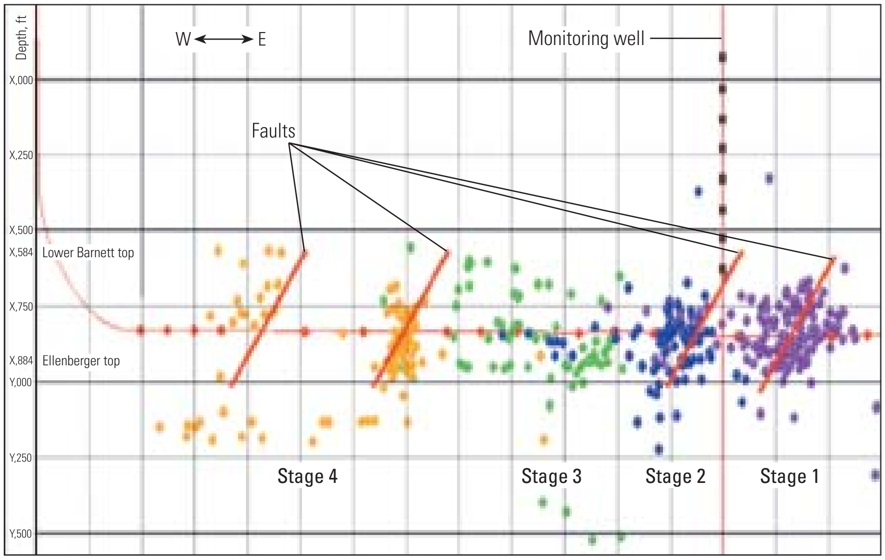
In August 2005, Chesapeake used the StimMAP service on another horizontal well in Newark East field to determine the influence of a faulted karst zone on hydraulic fracture geometry and orientation. Again, the stimulation involved four stages—slickwater treatments for Stages 1, 3 and 4, and a CO_2-fluid system for Stage 2. The treatments were monitored from a well south-southwest of the east-southeast-oriented horizontal leg of the treatment well. The distance from the hydraulic fracturing to the monitoring well ranged from less than 500 ft [150 m] to more than 2,000 ft, depending on the location of the stage along the horizontal wellbore (below and right).





Well	Number of events	Perforated interval, TVD from MSL, ft	Fracture system top, TVD from MSL, ft	Fracture system bottom, TVD from MSL, ft	Fracture system height, ft	SSW extent, ft	NNE extent, ft	Fracture system length, ft	NNW extent, ft	SSE extent, ft	Fracture system width, ft	Azimuth
Stage 1	140	X,970	X,744	Y,235	491	419	264	683	758	347	1,105	N15°E
Stage 2	98	X,954	X,483	Y,346	863	739	178	917	551	617	1,168	N15°E
Stage 3	68	X,954	X,670	Y,655	985	799	676	1,475	400	847	1,247	N15°E
Stage 4	94	X,949	X,682	Y,319	637	1,038	630	1,168	393	1,549	1,942	N15°E

^ Maps of microseismic events from another four-stage hydraulic fracture treatment. The StimMAP displays include a three-dimensional (3D) view (*top*) and a plan view (*middle*). The treatment stages are color-coded: Stage 1 is purple, Stage 2 is blue, Stage 3 is green, and Stage 4 is yellow. Also included is a summary of each stage, including acoustically determined fracture system length, width and preferential azimuth (*bottom*). Depths are given relative to mean sea level (MSL).



^ Influence of faults on Barnett Shale stimulation. Chesapeake placed perforations along the horizontal completion interval to avoid fracturing into four known faults. Even with the precautions, the StimMAP hydraulic fracture stimulation diagnostics interpretation indicated that the microseismic activity was concentrated around some of the fault planes and influenced by the presence of faults near Stages 1, 2 and 4.

Chesapeake knew the location of four faults in the area from seismic images and well control, so engineers placed multiple perforation clusters within each stage to avoid directly fracturing into the faults. Even with these precautions, fracture initiation was influenced by the presence of faults near Stages 1, 2 and 4 (above). Stage 1 most likely communicated with a fault. The microseismic and pressure evidence supported this scenario. The bulk of the microseismic events occurred between the second and third set of perforations, and the instantaneous shut-in pressure for Stage 1 was significantly lower than that of the other three stages.

The StimMAP service achieved Chesapeake's objective of defining the orientation and geometry of the hydraulically created fractures in the treatment well. Engineers determined that the dominant fracture azimuth was N15°E. While fracture-height growth was largely symmetrical and upwardly contained within the Barnett Shale, downward growth was observed in all stages. Laterally, Stage 3 demonstrated symmetrical growth, whereas growth in Stages 1, 2 and 4 appeared asymmetrical.[33] The StimMAP interpretation also concluded that there was little communication between the different stages.

Today, much of the effort to monitor hydraulic fracture growth is directed toward fracture stimulations in horizontal wells to assess fracture height and complexities associated with fracture interference. These issues cannot be addressed in horizontal wells with the near-wellbore evaluation methods previously mentioned. The ability to measure hydraulic fracture characteristics allows engineers to judge the impact of completion and stimulation design changes—for example, varying the placement or spacing of perforation intervals along the horizontal wellbore or altering proppant carrier fluids. Because of improved hydraulic fracture characterization, the effectiveness of hydraulic fracture treatments in the Barnett Shale has been linked to the opening of secondary natural fracture systems, which increases the width of the treated volume.

Testing Technologies, Models and Limits in Japan

Even though microseismic monitoring techniques have been available for years, the quest to improve velocity modeling, data acquisition, processing and interpretation continues. Japan Exploration Company (JAPEX) and Schlumberger collaborated on a project to test the feasibility of microseismic monitoring in the Yufutsu gas field, Hokkaido, Japan.[34]

The reservoir in the Yufutsu field is a naturally fractured, Cretaceous-age granite and overlying conglomerate located at depths from 4,000 m [13,124 ft] to 5,000 m [16,405 ft]. Within the field, there is no apparent correlation between gas production and well location or well orientation. However, JAPEX has determined that productivity is controlled by the local stress condition and by the distribution and orientation of several natural fracture systems across the field.[35] More specifically, large-aperture natural fractures, or "mega" fractures, oriented parallel to the maximum horizontal stress, act as gas conduits, while small-scale fractures affect gas storage and migration. Characterization of the fracture systems has been successful at the wellbore, using borehole-imaging devices such as the FMI Fullbore Formation MicroImager tool. However, to understand more about reservoir behavior and to improve reservoir modeling using a discrete fracture network simulator, JAPEX needed to investigate a larger reservoir volume.[36]

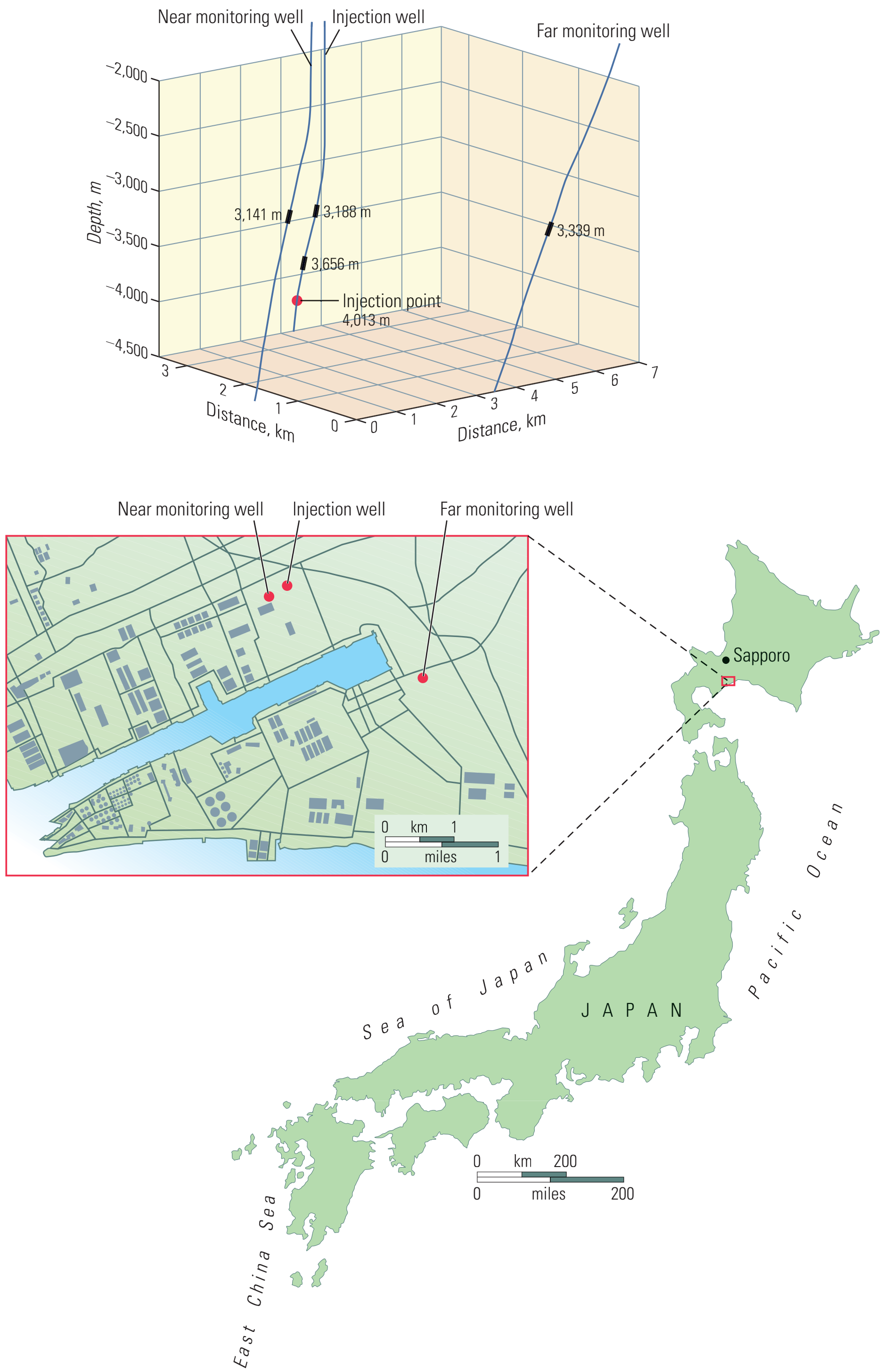
A preliminary injection test using a four-level VSI tool occurred in October 2003. In December 2004, JAPEX installed tubing-deployed, permanent seismic monitoring technology, the Vetco

Gray PS[3] system, in the SK-2D treatment well to record production-induced AEs. JAPEX observed only minimal microseismicity in the field, probably because of the lack of pressure drop in the reservoir. However, microseismic activity was induced during injection operations that initiated shearing along preexisting natural fractures. Consequently, recording and analyzing these AEs using hydraulic fracture monitoring techniques could help define the geometry and extension of the natural fracture systems. A VSP and a small-scale injection experiment were conducted in February 2005, and a large-scale injection experiment was performed in May 2005 (right).

The VSP data were used to enhance the existing velocity model and ultimately proved important in the fracture analysis. Using a seismic airgun source placed in a specially designed pit at surface and 1¹¹⁄₁₆-in. Createch SAM43 seismic acquisition tools deployed within production tubing in near and far monitoring wells, a 49-level VSP was recorded across the pertinent interval in both wells simultaneously. The VSP provided good quality z-component—vertical-component—data that allowed Schlumberger and JAPEX scientists to evaluate the coupling quality of the Createch tools and to find the optimal tool position for a microseismic monitoring survey. Velocity information from the VSP survey was also used to correct the existing velocity model, which in turn improved the accuracy of calculated AE locations.

Another objective of the project was to evaluate the hydraulic fracture monitoring performance of the permanent, tubing-conveyed Vetco Gray PS[3] prototype system. An upper and a lower sensor were deployed in the SK-2D injection well. The PS[3] sensors were affected by electrical noise. However, once the noise was reduced by error-prediction filtering, *P*- and *S*-wave arrivals were observed. Although the prototype sensors also were affected by noise from pumping fluid in this completion, some of the AE events had sufficient signal-to-noise ratios to identify *P*- and *S*-wave arrivals. This test represented the first successful use of multiple sensors to map hydraulically induced AEs from an injection well.

Using criteria from multiple monitoring sensors for event discrimination, the 40-h, 500-m^3 [3,145-bbl] fluid-injection program in February produced 920 detectable events, of which 40 exhibited detectable *P*- and *S*-wave phases at three or four sensors and were locatable with reasonable confidence. A comparison of event locations was made between



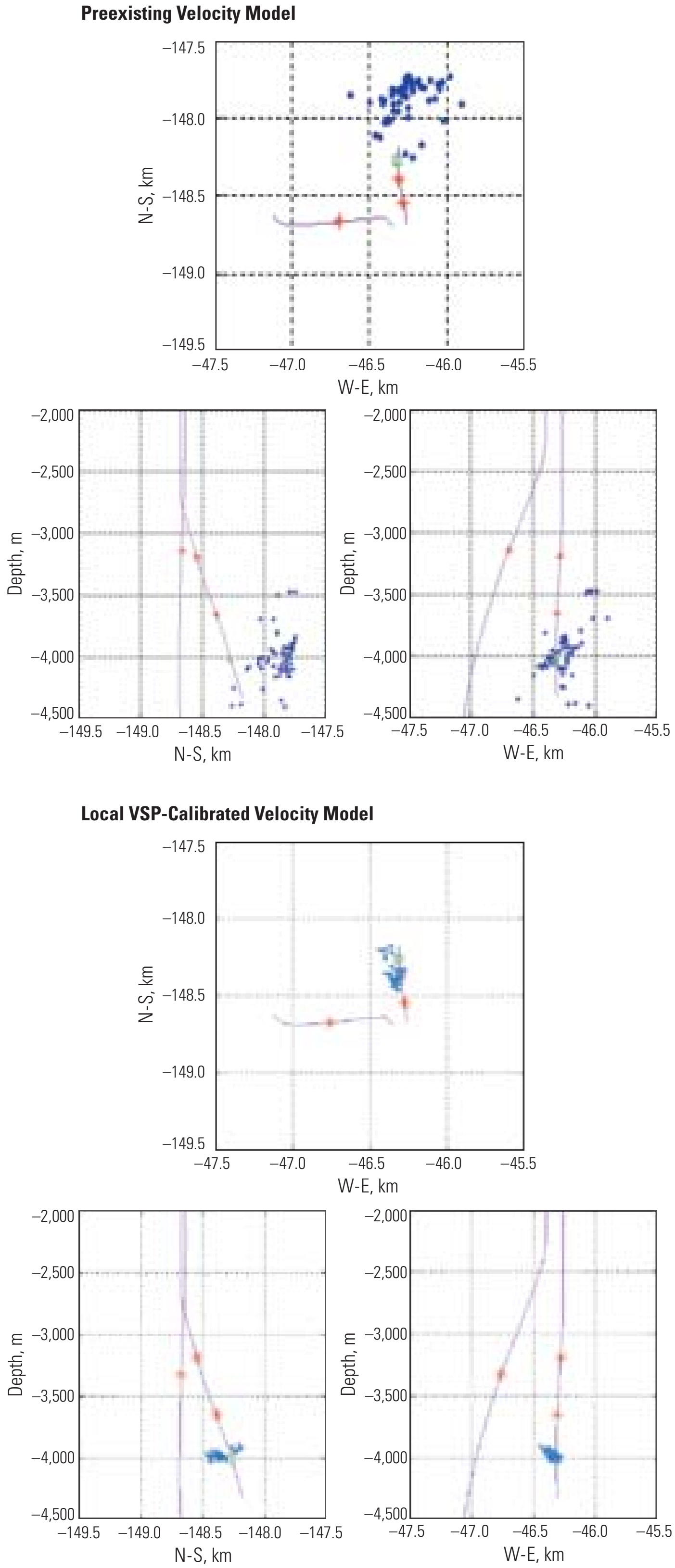
^ Geometry of the injection well, two monitoring wells and sensors with a map (*inset*) showing the experiment location.

33. The large distance between the monitor well and the reservoir volume affected by Stage 4 may be responsible for the asymmetry observed in the event locations.

34. Drew J, Primiero P, Leslie D, Michaud G, Eisner L and Tezuka K: "Microseismic Monitoring of a Hydraulic Injection Test at the Yufutsu Gas Reservoir," paper B, presented at the 10th Formation Evaluation Symposium of Japan, Chiba, Japan, September 29–30, 2004.

35. Tezuka K, Namaikawa T, Tamagawa T, Day-Lewis A and Barton C: "Roles of the Fracture System and State of Stress for Gas Production from the Basement Reservoir in Hokkaido, Japan," paper SPE 75704, presented at the SPE Gas Technology Symposium, Calgary, April 30–May 2, 2002.

36. Tamagawa T and Tezuka K: "Validation of Clustering of Fractures in Discrete Fracture Network Model by Using Fracture Density Distributions Along Boreholes," paper SPE 90342, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.



^ The impact of having a VSP-calibrated velocity model. A comparison of the February 2005 test microseismic event localizations using the preexisting velocity model (*top*) versus using the local VSP-calibrated velocity model (*bottom*) shows a tighter clustering of events using the updated model. This significantly reduces the uncertainty in defining hydraulic fracture geometry and orientation. In each of the displays, a plan view is shown on top, a north-to-south cross section is located in the lower left and a west-to-east cross section is shown in the lower right.

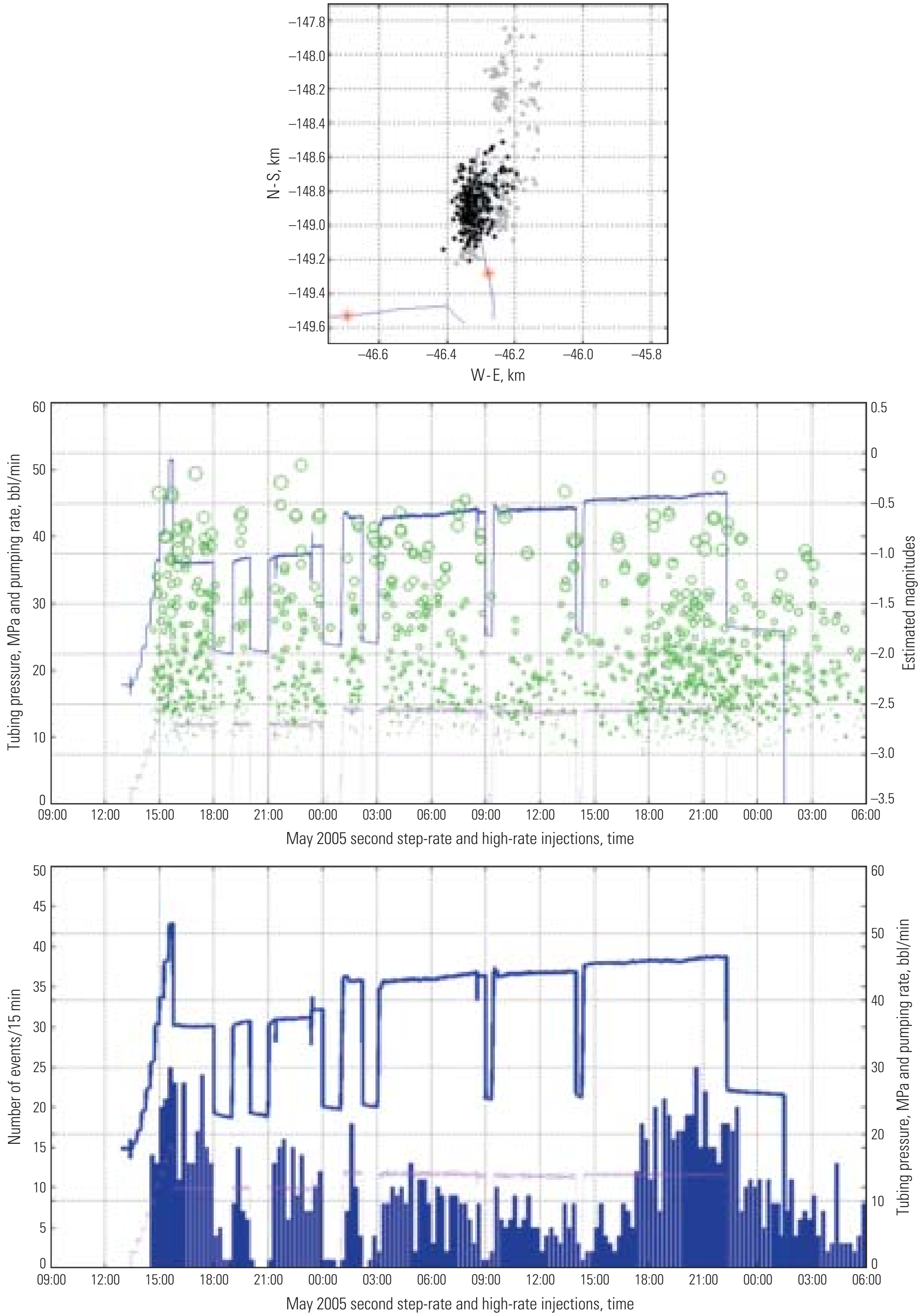
those calculated using the existing velocity model and those calculated using the VSP-refined velocity model (left). The revised velocity model significantly improved the source-location calculations, reducing uncertainty. The results using the new model showed a tighter cluster of activity than was evident using the previous velocity model, which had been built from VSP information obtained in other parts of the field.

The larger injection experiment in May pumped 5,600 m^3 [35,223 bbl] of fluid during six days in four different tests, or stages.[37] The experiment produced 447 located events out of a total of 2,515 detected events, some of which occurred after pumping had stopped (next page).

To determine the impact of monitoring from multiple wells, the event locations calculated using only data from the near monitoring well were compared with the event locations calculated using data from multiple monitoring locations. The criteria for multiwell localization were that clear *P*-wave and *S*-wave arrivals could be picked at the near well, that at least one *P*-wave arrival could be picked at the far monitoring well and that at a minimum one *P*- or *S*-wave arrival could be picked from the PS^3 treatment well data.

The localization algorithm was then run on both the single-well data and the multiwell data, using the new velocity model. With single-well data, distance to the event was calculated using the *P*- and *S*-wave traveltime data, and angles of ray incidence were determined using hodogram analysis. For single-well and multiwell processing, hypocenter estimates were made using the probability density functions formed from measured and modeled time delays and angles.[38] The single-well location cluster is more dispersed and more difficult to interpret than the multiple-well distribution, which also shows additional

37. Primiero P, Armstrong P, Drew J and Tezuka K: "Massive Hydraulic Injection and Induced AE Monitoring in Yufutsu Oil/Gas Reservoir—AE Measurement in Multiwell Downhole Sensors," paper 50, presented at the SEGJ 113th Annual Fall Meeting, Okinawa, Japan, October 16–18, 2005.
38. Michaud G, Leslie D, Drew J, Endo T and Tezuka K: "Microseismic Event Localization and Characterization in a Limited-Aperture HFM Experiment," *Expanded Abstracts*, SEG International Exposition and 74th Annual Meeting, Denver (October 10–15, 2004): 552–555.
    Tarantola A and Valette B: "Inverse Problems: Quest for Information," *Journal of Geophysics* 50 (1982): 159–170.



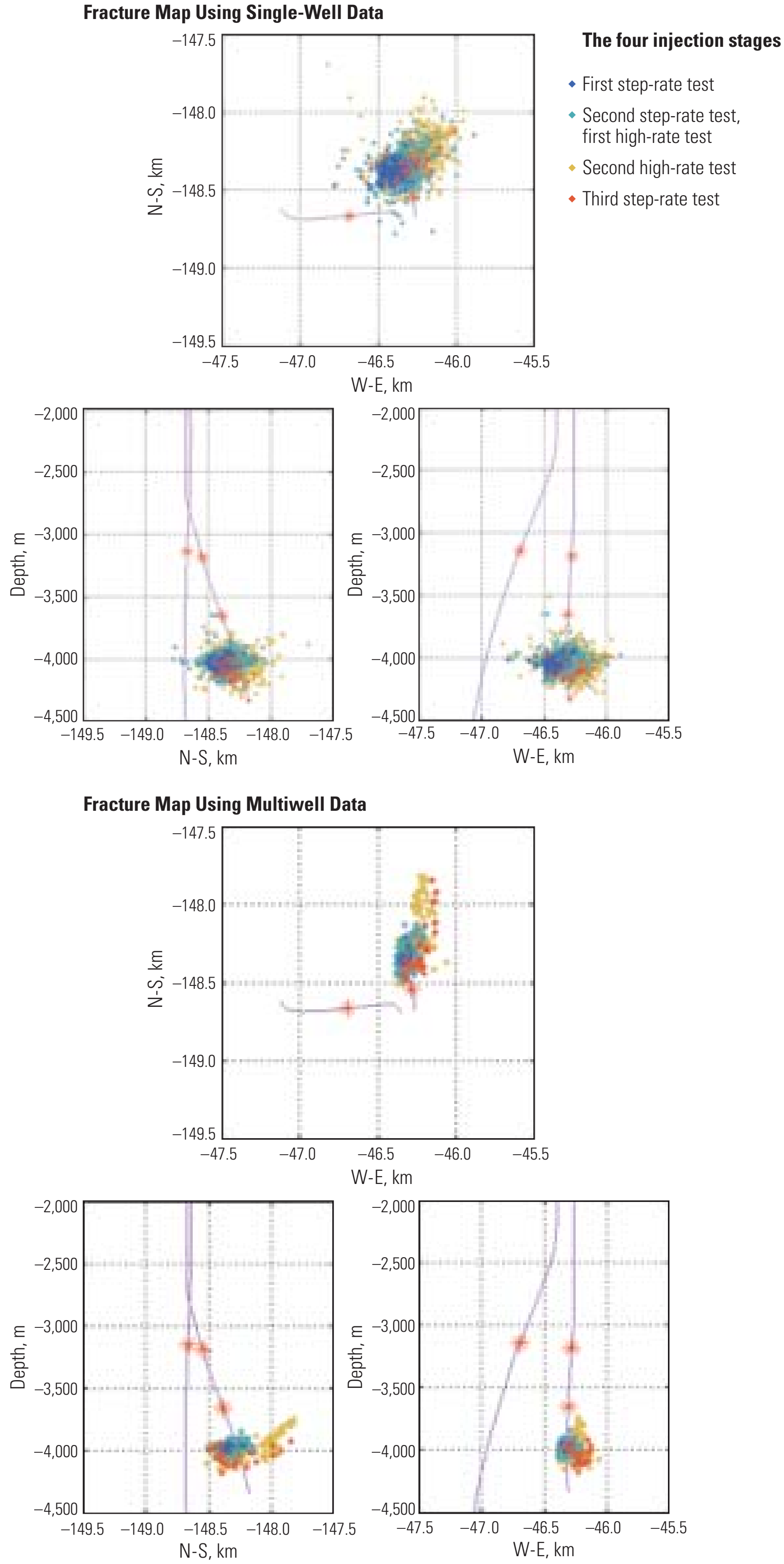
^ Examining acoustic emission (AE) magnitude and quantity during the second injection stage in Yufutsu gas field, Japan. This test started with a 2.5-h step-rate injection, followed by a series of 1-h high-rate injections, each followed by 1-h shut-in cycles. Next, a continuous injection rate of 14 bbl [2.2 m^3] per minute was maintained for 19 h, with an exception for scheduled pump maintenance. The middle plot displays estimated event magnitude. The size of the green ellipses is proportional to the signal-to-noise ratio. The number of microseismic events is shown on the bottom plot. Tubing pressure (blue) and pump rate (magenta) are displayed on both plots. A plan view (*top*) shows the located events that were attributed to this particular stage (black) of the total number of located events during the entire May 2005 injection experiment (gray). The beginning of the step-rate injection shows a pressure and rate threshold before AEs start to occur and, while the number of events decreases during the shut-in periods, AEs still occur in large numbers after pumping has stopped.

activity significantly farther to the north of the point of injection (right). The comparison between the two results highlights the challenge of monitoring hydraulic fracture behavior in the field, where monitoring options can be limited to a single well.

One of the primary motivations for acquiring pressure and AE measurements while monitoring the Yufutsu stimulation was the use of that information to validate reservoir-simulation models. JAPEX has developed a numerical simulator, which simulates the shearing of rocks, the associated AEs and the permeability enhancements during hydraulic simulation.[39] Comparison of simulated and measured AE event locations along with iterative matching of pressure histories was used to help confirm the validity of the simulations.

In addition to improving the characterization of natural fracture systems and reservoir modeling in the Yufutsu gas field, the injection experiments have confirmed the value of an accurate velocity model and the advantages of monitoring AEs from multiple stations. Although longer monitoring distances are less desirable, the experiment shows that monitoring can be done from considerable distances, depending on the geology. In this case, the farthest monitoring tool in the far monitoring well was about 2.5 km [8,200 ft] from the microseismic activity.

AE data provide information about the spatial distribution of the fracture system. Advanced mapping techniques such as the double-difference method and multiplet analysis provide source locations so precisely that AE clusters and fracture-related structures can be extracted.[40] For instance, the results of the double-difference method applied to the Yufutsu dataset gives multiple linear structures, which are interpreted as a medium-scale fracture system, bridging the



^ A comparison of event localization from one monitoring well and from multiple monitoring locations. The AE data from the May 2005 injection experiment were located based on the hodogram analysis—to determine angle—and *P*- and *S*-wave traveltimes—to determine distance. Fracture maps that used only data from the near monitoring well (*top*) were compared with fracture maps that used data from three monitor well locations (*bottom*). The use of multiple monitoring locations constrained the number of possible event localization solutions to yield fewer, but higher quality localizations, which produces a clearer representation of the activity.

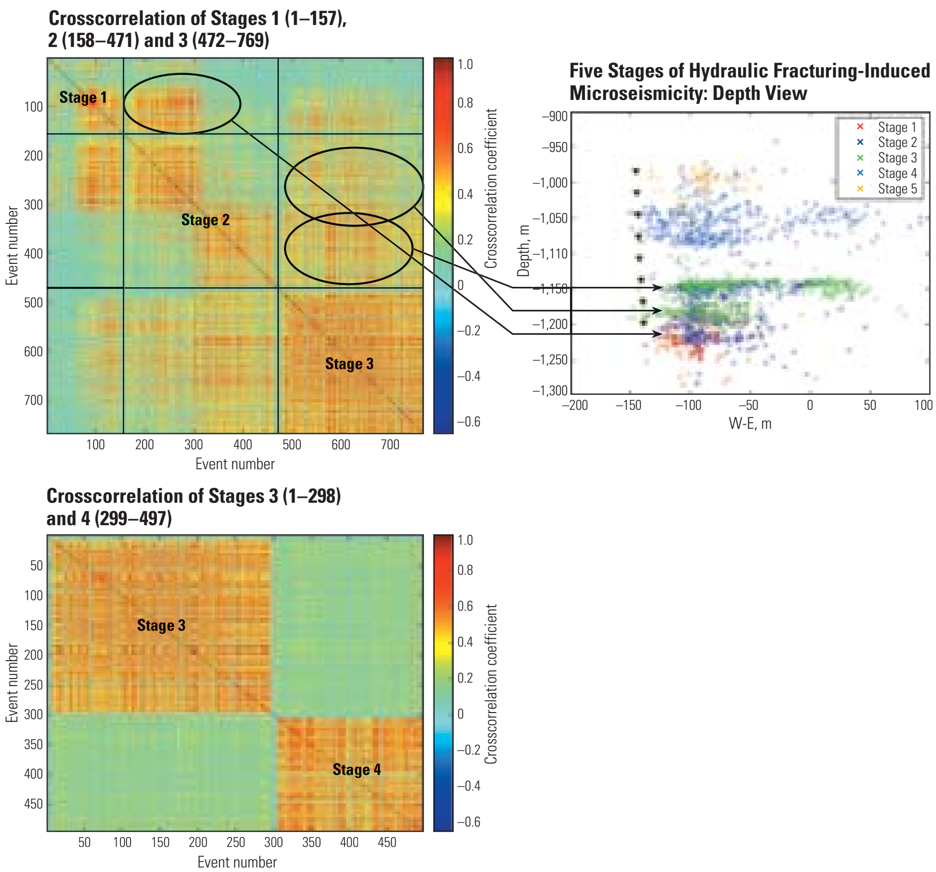
39. Tezuka K, Tamagawa T and Watanabe K: "Numerical Simulation of Hydraulic Shearing and Related AE Activity in Fractured Gas Reservoir," paper A, presented at the 10th Formation Evaluation Symposium of Japan, Chiba, Japan, September 29–30, 2004.

40. The double-difference method is a mapping technique that relates multiple pair of events relative to each other. Multiplets are clusters of nearly identical wavelets from multiple events with a similar focal mechanism that originate at the same, or very nearly the same, location but occur at different times.

41. Tezuka K, Tamagawa T and Watanabe K: "Numerical Simulation of Hydraulic Shearing in Fractured Reservoir," paper 1606, presented at the World Geothermal Congress, Antalya, Turkey, April 24–29, 2005.

42. Drew J, Leslie D, Armstrong P and Michaud G: "Automated Microseismic Event Detection and Location by Continuous Spatial Mapping," paper SPE 95513, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.

43. Eisner L and Sileny J: "Moment Tensors of Events Induced in Cotton Valley Gas Field from Waveform Inversion," paper P227, presented at the EAGE 66th Conference and Exhibition, Paris, June 7–10, 2004.



^ Detecting cross-stage hydraulic fractures using multiplets. The technique is based on the identification of multiplets as a result of reactivation of fractures from a previous stage. In this example from Texas, the upper graph is a crosscorrelation of all microseismic events from Stages 1, 2 and 3 (*top left*). Stage 1 includes Events 1 through 157, Stage 2 includes Events 158 through 471, and Stage 3 includes Events 472 through 769. The crosscorrelation coefficient is color-coded, identifying microseismic events in different stages that originate from the same fractures—multiplets. When Stages 3 and 4—Events 1 through 298, and 299 through 497, respectively—are crosscorrelated, the coefficient remains very low except where the stages correlate with themselves (*bottom left*). The event map reflects this observation (*right*).

gap between the fault system and fractures observed on borehole images.

Another advantage of AE data is that they provide spatial constraints for reservoir simulation. JAPEX developed the Simulator for Hydraulic Injection and Fracture Treatment (SHIFT) to simulate hydraulic injection experiments.[41] This simulator works on a discrete fracture-network model and simulates the shearing of preexisting fractures, related AE activity and permeability enhancement in a dynamic process. It does this by coupling fluid-flow analysis and shear-induced fracture-dilation analysis. The AEs and the injection pressures observed during the experiment were used for the postjob matching analysis. The size, orientation and migration history of the AE cloud helped constrain the model parameters. In addition, AE clusters can be used as deterministic information to modify the fracture network directly. The Yufutsu project involving JAPEX and Schlumberger tested some of the inherent limits of hydraulic fracture monitoring.

New Microseismic Activity

One of the major limitations in microseismic monitoring methods is finding candidate treatment wells that have a nearby monitoring well, or wells, in which to install the VSI tool. Not only does the monitoring well need to be relatively close to the treatment well, depending on the acoustic properties of the surrounding rock, but it must also be well cemented and acoustically quiet during fracturing operations. Ensuring that the monitoring wellbore is in the appropriate condition prior to running the VSI tool often requires significant time and expense.

Scientists continually search for the balance between dependable AE detection and localization, and expedient processing and interpretation that provides useful answers at the treatment site. With the advent of faster computers, a new method that uses coalescence microseismic mapping (CMMapping) has achieved fast and reliable event localization for reliable real-time fracture mapping.[42]

Another challenge addressed by Schlumberger geophysicists when detecting and locating AEs is the identification and interpretation of multiplets. For example, multiplets have been observed to occur during two different pumping stages. Identical microseismic responses arise from, and are mapped back to, the same source locations. Therefore, multiplets indicate the reactivation of a fracture or fault for which activity was detected earlier. During a multistage hydraulic fracture treatment, this may indicate crossflow between stages, resulting in an ineffective stimulation. The key is being able to identify the occurrence of multiplets in real time so that actions can be taken while pumping. Schlumberger scientists have developed a crosscorrelation method to detect crossflow between stages that also provides another layer of quality control in real-time event localization (left).

Scientists at Schlumberger Cambridge Research are also developing a robust seismic inversion to determine the mechanisms of the observed microseismic events, for example, shear or tensile mechanisms.[43] This technique allows going beyond "dots in a box" and, for example, quantifying stress changes resulting from microseismic events. This information is used to further constrain geomechanical models and provide companies with a better understanding of hydraulic fracture propagation or stress changes in the fractured reservoir.

Hydraulic fracture mapping has much to offer the E&P industry, especially in tight reservoir development. Accurate fracture models, calibrated using direct measurements of hydraulic fracture geometry, lead to improved reservoir simulation and development. After decades of searching for the best way to characterize hydraulic fractures, the industry has returned to the best source for the answers to our questions—the hydraulic fractures themselves. —MGG