THE AMERICAN OIL & GAS
REPORTER®
OCTOBER 2012

The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Tools Identify Stress-Related Fractures

By Adam Baig,
Katherine Mountjoy
and Ted Urbancic

KINGSTON, ONTARIO–Characteristics of fracture growth can demonstrate considerable variability not only between wells in the same field, but also between stages on the same well undergoing similar treatments. Formation heterogeneity may be responsible for this variation. However, an equally likely reason may be the presence of larger geological structures in and around the reservoir.

Structures such as faults may act to perturb local stresses and the presence of such features can have significant consequences on the propagation of hydraulic fractures. Where some treatments may be designed to activate a certain joint set in a given stress regime, the rotation of these stresses as a result of nearby structures may cause other pre-existing fracture sets to activate.

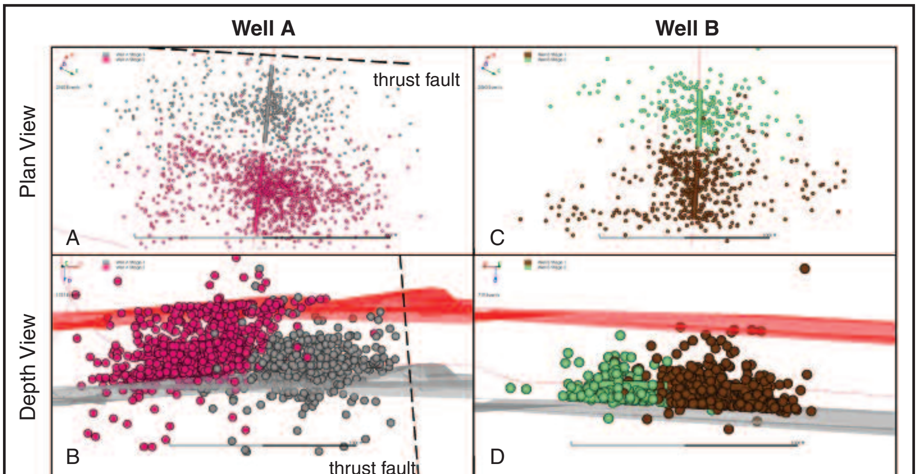
Failure to account for the heterogeneous stress regime imposed by larger-scale fault structures can lead to unexpected, and generally suboptimal, results for the fracture stimulation. The interaction of these fractures leads to a complex pattern of fluid flow and fracture interconnectivity that affects the shape of drainage volume and plays a role in whether effective proppant transport is achieved.

Many geological structures are too small to be identified using traditional seismic surveys. Microseismic monitoring of hydraulic fracture treatments is used frequently to characterize and visualize fracture growth, but microseismic event distributions also may show where these unknown primary or secondary geological structures exist and when they are activated. As stress distribution in the reservoir is altered by hydraulic fracture stimulation, small-scale microearthquakes (microseismic events) ranging from -4 to 0 on the magnitude scale can be detected by monitoring equipment located in a nearby monitoring well or on the surface.

The unusual clustering of microseismic events away from the treatment zone, or the observation of larger-magnitude seismicity (magnitudes above 0) consistent with slip along a fault may indicate the activation of a geological structure and warrant further investigation using advanced microseismic techniques.

FIGURE 1

Microseismic Events from Two Marcellus Wells



In this image, microseismic events from four stages (two in each well) are shown in both plan and cross-sectional views, colored by stage in well A (left) and well B (right). Cross-sectional views also depict the top and bottom of the Marcellus as red and gray surfaces, respectively.

SMTI

The current state of microseismic analysis in the oil and gas industry can offer a wealth of information beyond event locations and magnitudes that may help operators further understand the fracturing process. The failure mechanisms of microseismic events are represented by the moment tensor. A new patent pending process of seismic moment tensor inversion (SMTI) involves projecting the amplitudes and polarities (first motions) of the compressional and shear waveforms back to the event hypocenter to determine the failure mechanism responsible for generating the microseismic event.

In order to get a stable solution, it is essential that the sensors recording the waveforms be deployed in a three-dimensional network around the events. For downhole deployments of geophone arrays around hydraulic fractures, this means that at least two or preferably more arrays need to be deployed to record the data.

Generally, the mechanism is consistent with a failure on a fracture plane, where the types of failures usually are considered to be opening of cracks, crack-closure, slip on a fracture plane, or a combination of failure modes. The orientation of the fracture plane follows from the mode of deformation. It is also possible to determine the size of the fracture plane by looking at the spectral response of the microseismic waveforms.

By idealizing the failure process as a failure of a penny-shaped crack, the natural (corner) frequency of the event is related to the size scale (source radius) of this crack. As a result, a three-dimensional discrete fracture network can be defined that outlines the size and orientation of fractures associated with microseismic events, and therefore, can be used to indicate specific natural primary or secondary fracture sets that are being activated.

While it is recognized that the existence of geological structures within a formation can significantly impact local stress regimes, how this impacts hydraulic fracture treatments remains relatively unknown. A microseismic data case study from the Marcellus Shale demonstrates how larger-scale geological structures can dramatically alter the stress fields in a formation and perturb the activated natural fractures. In this example, the target reservoir was extensively naturally fractured, and unusual fracture behavior was attributed to the influence of a nearby geological structure.

Marcellus Joint Sets

The organic-rich, Devonian-age Marcellus Shale formation is cross-cut with two regional joint sets (J1 and J2), as observed in outcrop, core and bore hole images. J1 strikes east-northeast and is more closely spaced than J2, which strikes northwest. When present, these joint sets align optimally with natural stresses, making them ideal contributors to production through horizontal hydraulic fracturing.

Typically, as in this case, horizontal wells are drilled perpendicular to the direction of maximum horizontal stress (S_{Hmax}) and often cross-cut and drain J1 joints, while hydraulic fracture stimulations propagating in the direction of S_{Hmax} result in the cross-cutting and drainage of J2 joints. Further contributing to fracture complexity, the Marcellus is also very fissile, splitting easily along subhorizontal bedding planes.

Four treatments from two wells on the same pad in the Marcellus Shale in Pennsylvania were examined in detail, using moment tensor analysis techniques. Structurally, as shown in Figure 1, the A set of wells is separated from the B wells by a fault and associated subtle anticline. Both stages occur near the heels of their respective wells and were pumped with similar treatments.

The cross-sectional views of the microseismic event hypocenters illustrate differences in the vertical growth of events between the two wells. Events in well A experienced significant growth, while the events in well B on the far side of the anticline remained well contained within the target formation.

SMTI and discrete fracture network analysis on the events from these four stages revealed key differences in the orientations of the fractures for the events in well A compared with well B. Figure 2 provides stereographic projections to express the orientation of poles to fracture planes as determined through SMTI for each stage shown in Figure 1. Dominant fracture orientations for each stage are expressed in white, while the local joint sets J1 and J2 are shown in green on the projections.

For the stages in well A, the dominant fracture sets appear to correspond with one or both of the joint sets. Although well B is located on the other side of the same pad, the dominant fracture set is observed to be subhorizontal, striking west-northwest and dipping between 15 and 20 degrees, suggesting that the dominant failure mechanism in these stages involves the fissile delamination of bedding planes rather than the activation of existing fractures. It can be suggested that the presence of the nearby fault and associated anticline has altered the local stress regime such that the fractures prefer to activate the joint set rather than the bedding planes as in well B.

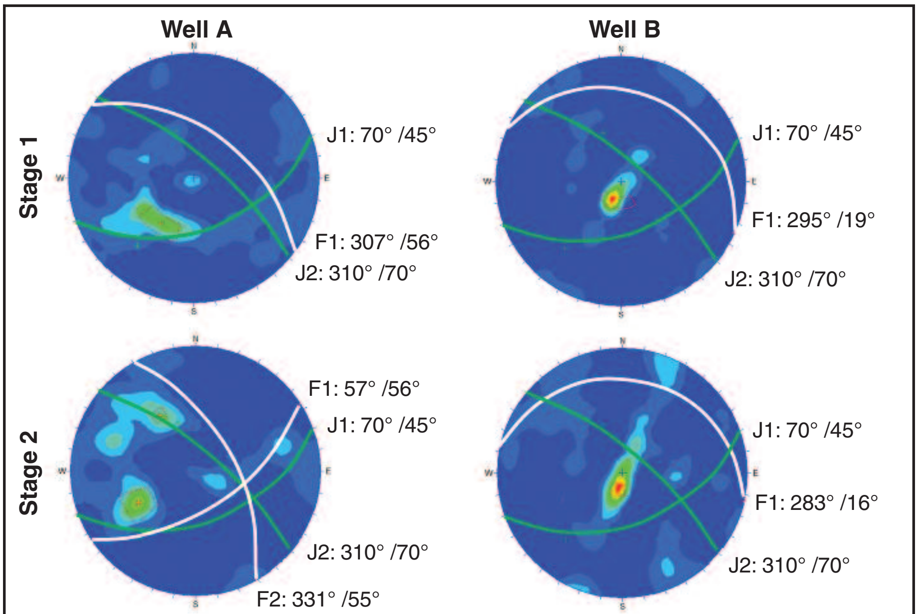
This highly localized stress control results in dramatically different stimulation behaviors between the stages discussed. Since fracture treatments usually are designed to stimulate certain fracture sets, accounting for the presence of stress-altering geological structures is critical to optimizing production from nearby wells. Understanding this process of stress reorientation allows for treatment programs to consider selective stimulation of fracture sets, and an approach to increase fracture intensity and complexity.

Injection-Induced Seismicity

Interacting with fault structures during hydraulic fracture stimulations can yield

FIGURE 2

Stereographic Projections of Fracture Planes Determined Through SMTI



Shown here are lower stereographic projections of the SMTI-derived fracture planes for stages 1 and 2 in wells A and B, as shown in Figure 1. The fracture planes (white) are compared with dominant joint sets J1 and J2 (green).

unexpected behavior for operators, but also has the potential to induce larger-magnitude events. It is not uncommon to observe microseismic events as large as magnitude 0 during hydraulic fracture stimulations in zones prone to faulting. Until recently, minimal evidence was available to link earthquakes large enough to be felt on the surface (magnitude generally greater than 2) to stimulation activities.

Historical evidence is available linking prolonged, high-volume fluid injections near large fault structures to induced seismicity; key examples include activities at the Rocky Mountain Arsenal in Colorado in the 1960s involving waste injection, and earthquakes in Basel, Switzerland, in 2006 and 2008 that were linked to nearby geothermal operations. In all of these examples, the resulting induced seismicity was large enough to be felt on the surface, but small enough to avoid significant property damage.

In high-volume fluid injections, interaction with fault structures can alter pore pressure, overcoming natural stresses and pushing the fracture closer to failure. By lubricating the surfaces of the fault, fluid injection may enable slip along the fault surface where no slip would have occurred otherwise.

With an increased public concern about induced seismicity, operators are particularly aware that activating existing faults and structures may trigger larger-magnitude events. Broad range or hybrid monitoring of induced (micro)seismicity monitoring is a key technology that can help operators understand the relationship between injections and their interaction with fractures of different scales.

By providing operators with accurate knowledge of the size and location of larger-magnitude events, the industry not only can move toward establishing a system of evaluating induced seismicity while demonstrating responsible operation and environmental compliance, but it can use the information to more fully define the discrete fracture network of primary and secondary fractures. Such an approach extends the known power law distribution of fractures and provides greater control of inputs into reservoir models to optimize stimulation programs and enhance reserve estimates.

It is important to note that microseismic technology generally is tuned to only identifying the small-magnitude seismicity generated during hydraulic fracture stimulations (M<0). The most commonly used microseismic sensors are 15 hertz geophones deployed down monitoring wells at reservoir depth. Microseismic events occur on relatively small fractures, resulting in relatively high-frequency signals propagating through the earth.

In contrast, large-magnitude events (M>0) exhibit much longer waveforms and travel at significantly lower frequencies. In order to accurately capture the low-frequency signal content associated with large-magnitude events, the types of sensors used to acquire seismic data must be tuned to this low-frequency signal. This is achieved easily by incorporating sensors such as 2.0- or 4.5-hertz geophones or force balanced accelerometers (FBAs) into a seismic network.

A new hybrid downhole/near-surface monitoring solution has been launched that is designed to provide this desired broadband range of seismic detection. By integrating downhole and near-surface receivers, operators are able to view the small-magnitude seismicity related to hydraulic fracture stimulation to optimize production, while also taking advantage of a near-surface seismic system equipped with sensors tuned to the frequencies inherent in larger-magnitude seismicity.

Large-Magnitude Events

In one example, two relatively large-magnitude events close to M3 occurred within close proximity of a hydraulic fracture completion operation on two consecutive days in a naturally fractured shale play, and were strong enough to be seen on a regional seismic station 100 kilometers away from the treatment site. The regional network can locate such events only to accuracies of 10 kilometers or better, which is insufficient to be able to distinguish whether such events are occurring on pad or off pad, or answer critical questions on the depth of the events and relationship to the completion program.

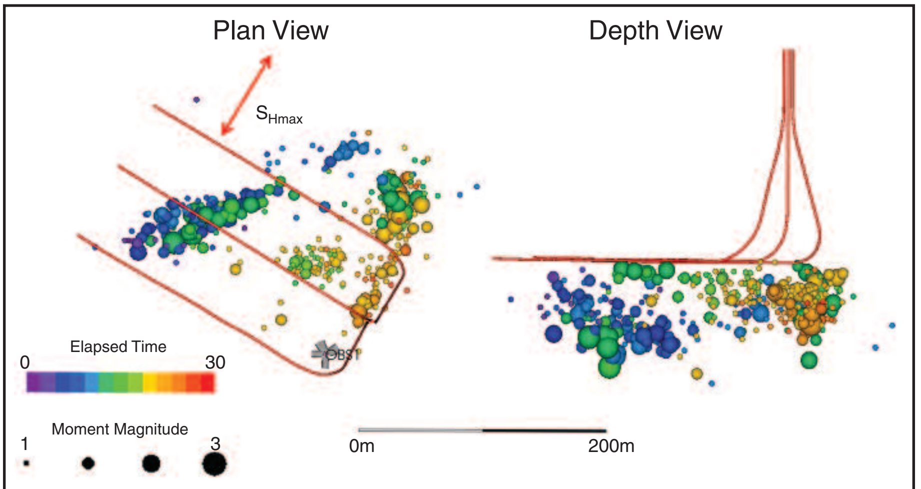
The large-magnitude events subsequently were followed by hundreds of smaller (M>0) events. These signals were recorded simultaneously on a network of near-surface 4.5-hertz geophones and FBAs, providing enough resolution to answer questions on the nature of the large events.

The events are depicted in plan view on the left in Figure 3, with the well pad and one of the surface stations shown for reference. Events are colored by elapsed time scaled by size to represent their moment magnitudes. Examining the occurrence of events in time suggests that the events are closely related to the treatment program, with the earliest events occurring near the toes of the wells and migrating toward the heels of the wells over time.

The same events are shown in depth view on the right of Figure 3. The large events appear to be located beneath the wells and the target formations. Two distinct trends are visible in the event locations in plan view: The early events follow a trend roughly 30 degrees from S_{Hmax} and the later events follow a lineation

FIGURE 3

Large-Magnitude Microseismic Events in Plan and Depth Views



In the plan (left) and depth (right) views of the event distribution over the pad, the events are colored by elapsed time, and the size scale corresponds to moment magnitude. One of the five observation stations is depicted in the plan view and the direction of S_{Hmax} is noted also. The treatment wells are displayed in red.

approximately parallel to S_{Hmax}.

In addition, a third cluster of events is spatially located between the two linear distributions. The distribution of the first cluster of events is optimally oriented to slip, given the direction of S_{Hmax}. The second linear cluster is in good agreement with the expected event trend, as if the regional stress were controlling the overall event distribution.

We suggest that the large events observed are activating larger, fault-scale features beneath the treatment formation that are optimally oriented to slip in the stress field in which the events are occurring. The recorded waveform peak values are in accord with reports of these events being felt on the surface.

Recognizing that events generated during hydraulic fracturing can have the potential to be felt on the surface is important for a number of reasons. From a perspective of due diligence, such events need to be as accurately characterized as possible in terms of location and source parameters (including magnitudes, but also source radii).

Finally, if these events are generating ground motions large enough to be felt on the surface, there needs to be an assessment of the seismic hazard on site to answer questions about where shaking may be most intense and the standards equipment needs to be built to withstand such motion.

New opportunities to integrate broad-range microseismic data with geological data have the potential to enhance understanding of local stresses in the proximity to faults and other geological structures.

The interaction of hydraulic fracture stimulations with unknown structures can significantly impact fracture propagation by altering which fracture sets dominate the stimulation. Interaction with larger fault structures also has the potential to induce larger-magnitude seismicity, resulting in increased public concern surrounding the hydraulic fracture industry.

There exists an opportunity to take advantage of microseismic technology to better understand subsurface geology during hydraulic fracture stimulations. By understanding how geological structures impact local stresses in a treatment zone, operators can refine treatment programs to account for this interaction, ensuring successful, responsible operations and maximizing production. ❐

ADAM BAIG

Adam Baig is a seismologist at ESG Solutions in Kingston, Ontario. He has been working at ESG Solutions since 2008, developing advanced processing techniques for microseismic data applied to hydraulic fractures and petroleum reservoir monitoring. He completed his Ph.D. at Princeton University in 2003, focusing on finite-frequency effects of wave propagation. He then moved on to two post-doctoral positions, first at the University of British Columbia focusing on passive, teleseismic monitoring of earthquakes, and in 2006 at Université Joseph Fourier in France, studying seismic noise interferometry.

KATHERINE MOUNTJOY

Katherine Mountjoy is an engineer at ESG Solutions and has spent the past four years in various technical and marketing roles. She currently holds the position of technical marketing coordinator. Her primary focus has been examining the integration of microseismology with fracture engineering and geomechanics to create a higher level of understanding about the applications of microseismic in unconventional oil and gas production. Prior to joining ESG, Mountjoy completed an M.S. in engineering at Queen's University in Canada.

TED URBANCIC

Ted Urbancic is a founder of ESG Solutions and holds the position of executive vice president for ESG's Global Energy Services. He is a pioneer in developing microseismic monitoring for industrial applications. In recent years, Urbancic's primary focus has been using seismic source techniques to constrain numerical models for reservoir optimization, and evaluating hydraulic stimulation and enhanced oil recovery-induced seismicity. His work examines using microseismicity to characterize and understand fracture development. Urbancic holds a Ph.D. in seismology from Queen's University in Kingston, Canada.