Micro-seismic monitoring provides new insights into hydraulic fracture propagation

Calvin Kessler and Dan Quinn of Halliburton* describe the company's use of micro-seismic mapping for the improvement of fracture modelling as part of optimizing recovery of reservoir resources.

The viability of many low-permeability reservoirs often depends on hydraulic fracture stimulation and re-stimulation programmes. Understanding the effect of the fracturing process on a formation is critical to designing a successful stimulation program and optimizing reservoir production.

Micro-seismic mapping of these unconventional assets, such as tight shales and coalbed methane reservoirs, provides unique insights into fracture propagation that improves the accuracy of fracture modelling, helps define best practices, and aids in increasing optimal recovery.

The significance of micro-seismic analysis in the success of many unconventional plays has resulted in a growing expertise in the field and advancement of the technology. Recent innovations are drawing on related capabilities in logging technology and borehole seismic services. These advancements are providing operators with a new understanding of fracture performance, with a commensurate improvement in production results. Recent innovations in the industry, such as a micro-seismic fracture-monitoring service offered by Halliburton, are drawing on these advancements to reveal details of hydraulic fracture propagation as they happen.

Modelling using micro-seismic data

The fracture propagation insights provided by micro-seismic technology rely on information gained from microearthquakes – slippages or tensile deformations that occur along natural fractures and emit detectable seismic energy. Although most micro-earthquakes occur naturally due to tectonic processes, man-made micro-earthquakes, or micro-seismic events, arise from changes in stress and pore pressure associated with stimulation, production, and fluid injection.

Micro-seismic technology has been highly effective in helping develop the tight formations that are becoming increasingly common in the industry. Its contributions improve the effectiveness of hydraulic stimulation treatments required for these unconventional resources to reach their full production potential. The technology is proving especially useful to operators as they ramp up their efforts to extract reserves from shale formations around the world. Deposits in the US, Russia, and Brazil account for more than two-thirds of the world's shale resources, with the remaining deposits scattered throughout Canada, Australia, Sweden, Estonia, Jordan, Israel, Syria, Morocco, Turkey, Thailand, France, Germany, and China. In the US, Texas currently produces the majority of shale hydrocarbons and formations in other states from Wyoming, Louisiana, Arkansas, to Pennsylvania are of growing interest and activity.

These tight shale deposits once played a minor or nonexistent role in gas production due to lower permeability that made producing them difficult. But with increased oil and gas prices and significant advances in the ability to understand and fine-tune hydraulic fracturing designs, this challenging resource has become a target for modern development activity. Micro-seismic monitoring of the effects of fracturing is playing a major role in the industry's understanding of how these reservoirs should be developed.

Technology advances

A proprietary diagnostic and monitoring service developed by Halliburton combines expertise in logging technology and borehole seismic services with the science of microseisms. It is an example of the advances happening in micro-seismic monitoring. Among the key benefits is monitoring that allows identification of fracture geometry in real time, while pumping.

The service involves highly accurate mapping of microseismic events in X, Y, Z coordinates and time. This data is used to update the 3D reservoir model, improving reservoir inflow modelling predictions and economic analyses.

Using this workflow, fracturing engineers can obtain the data needed for both prestimulation stress profile modelling and velocity profiling for borehole seismic modelling, as well as construction or validation of geomechanical models.

The system, based on proven borehole seismic sensor technology, is designed for use in open and cased holes using a standard seven-conductor cable. Reliable performance, even in hostile wellbore environments, is ensured by an array of 3 in downhole sensors rated at 25,000 lb per in^2 (psi) and temperatures greater than 350^o F. The sensors are available for use in a wide range of hole sizes from 3.5-22 in.

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The service is part of a service model for integrated exploration and production activities that enables a real-time, collaborative environment to model, measure, and optimize assets. The model enhances oil and gas operators' integration by creating a link through open, cross-disciplinary workflows. These workflows automatically share data and ultimately deliver reliable results that reduce risk.

Micro-seismic origins

Fracture monitoring using micro-seismic technology was conceived more than four decades ago as an extension of fault movement monitoring. Previous technology utilized a triaxial acoustic detector, or geophone, in the same borehole in which the hydraulic fracture treatment was applied. Monitoring was practical only after pumping, since environmental noise associated with fracturing fluids passing the geophones masked the micro-seismic events during the treatment. This limited results, because events occurring after pumping are generally located in the far field and are associated with fracture closure, not propagation.

Improvements in borehole seismic sensors have encouraged a resurgence in the use of micro-seismic technology in the last 10 years, with current technology utilizing a two-well monitoring process. On pad locations, a single monitor well can be used for multiple well stimulation operations, and it is now able to acquire and process micro-seismic data in real time. Applying this technology alongside a traditional fracture design model constructed using well log, seismic, and geomechanics information can significantly increase fracturing effectiveness.

Using it with dipole sonic and petrophysical data enables geoscientists to perform pre-job modelling that determines the optimal offset well for monitoring the treatment, identifies the depth interval for placement of geophone array in the monitor well, and helps develop a multilayer velocity model.

Improving the process

Monitoring of micro-seisms enables evaluation of hydraulic fracture propagation for real-time assessment of the fracturing process while the job is underway. Applications of this technology include mapping the extent of fractures during hydraulic fracture treatments, fault mapping, and time-lapse 4D seismic monitoring of gas or water fronts within the reservoir.

To improve 3D hydraulic fracture modelling and treatment optimization, it is necessary that the location and growth of hydraulic fractures be known in terms of fracture azimuth, length, and height.

Fracture propagation generates compressional (primary or P) and shear (secondary or S) waves associated with the tensile or shear failure of the formation. The micro-seisms are detected by an array of geophones situated in a monitor well. These sensitive, three-axis, pod-mounted detectors can identify and map the precise location of the events in real time as the hydraulically-induced fractures propagate in the formation.

Because these micro-seisms are extremely small, sensitive receivers are required to measure the resulting seismic waves. P waves are typically fast, low-amplitude longitudinal waves with particle displacement generated parallel to the wave propagation. They help determine azimuth from the receiver array to the event. S waves are slower, moderate-amplitude waves with displacement generated perpendicular to the direction of wave propagation. A multilayered P and S wave velocity model may include the effects of deviated wellbores, dipping beds, homogeneous or heterogeneous formation characteristics, and anisotropy. This data is needed to accurately locate and map the micro-seism in complex geological conditions.

Each detected micro-seismic event is transferred to a second computer system to determine the location of the event in time and XYZ coordinates. This event location is identified with respect to the treatment wellbore, and time-stamped for correlation to the real-time job data. Background noise and micro-seismic events are continuously acquired by the borehole seismic array and transmitted for processing and analysis during and after the fracturing treatment.

Acquiring micro-seismic data after pumping for an hour or more (depending on formation and treatment properties) will provide micro-seismic events associated with the fracture closure. While the data is acquired, identified events are processed on a second computer, allowing event location and optimization of the processing parameters.

Also, the use of a second computer provides the on-site fracture monitoring system with the option of reanalyzing all complete data records using optimized processing parameters, such as enhancements to the velocity model. Alternatively, the system can analyze just selected data acquisition time-based segments.

Optimizing field development

Real-time 3D fracture mapping confirms the success of multi-zone fracturing and provides insight into geophysical, geological, and fluid flow dynamics for improved reservoir modelling. With greater reservoir understanding, operators have a clearer picture when determining optimum well spacing and placement. The technology enables operators to design drilling programmes that optimize field development through an enhanced understanding of drainage patterns and identification of undrained assets.

Because modern technology enables operators to listen in on miscro-seismic events during hydraulic fracturing and map fracture propagation as it happens, they know where their fracturing treatment is going and what it is doing. Fracture azimuth, length, and height are clearly defined, revealing details that confirm a successful fracturing job, allowing fracture modelling optimization and helping refine the reservoir models. Being able to watch fracture propagation in real time reveals the cause of many pressure responses observed during and after pumping.

With the resulting information, operators have a clearer understanding of what's happening downhole. They are able to map multiple stimulation stages and use 3D visualization to obtain an accurate picture of the reservoir and associated fracture-drainage patterns. The information is critical to optimizing infill drilling programmes, enabling future wells to be placed in a way that optimizes reservoir recovery, improves subsequent fracturing jobs, and minimizes uncertainty in fracturing programs.

Case histories

Symmetrical and asymmetrical fracture propagation
Mapping identified an asymmetrical fracture in a US well that clearly showed an unstimulated section of the reservoir. The data provided valuable insights into fracture performance and gave engineers quality data for improving well and treatment results. The micro-seismic monitoring was conducted on a two-stage hydraulic fracturing treatment of a Jurassic age tight sandstone reservoir in the ArkLaTex region (Southwest Arkansas, Northwest Louisiana, and Northeast Texas).

The system mapping screen plan view in Figure 1 shows the monitor well location about 1400 ft northeast of the treatment. In the first stage treatment of the lower zone, micro-seismic events in the yellow ellipse indicate a bi-wing fracture propagating in an east-west azimuthal direction nearly symmetrical about the axis of the treatment wellbore, with half-wing lengths of approximately 900 ft. In the transverse view, the light-blue shaded area indicates the target zone of the stimulation's first stage. The micro-seismic events indicate the treatment was accurate and stayed mostly in zone, with minimal downward fracture propagation with respect to paleo-slope and formation dip.

An identical hydraulic fracture treatment was performed on the shallower sand member. A composite bridge plug was set between the stage initiation intervals for wellbore isolation and the next interval was perforated utilizing the same perforating gun systems used for stage one.

Mapping of fracture propagation in the second stage is shown in Figure 2. The plan view indicates an asymmetrical single-wing fracture with an east-northeast azimuth (N 60° E). The blue shaded area in the transverse view indicates that out-of-zonal fracture height growth was also minimal in the second stage.

This single wing fracture indicates a possible undrained region of the reservoir in the sand to the west-southwest of the treatment wellbore. The geophone array was not moved between stages and the detection of the single wing fracture is not a listening distance or instrument sensitivity issue.

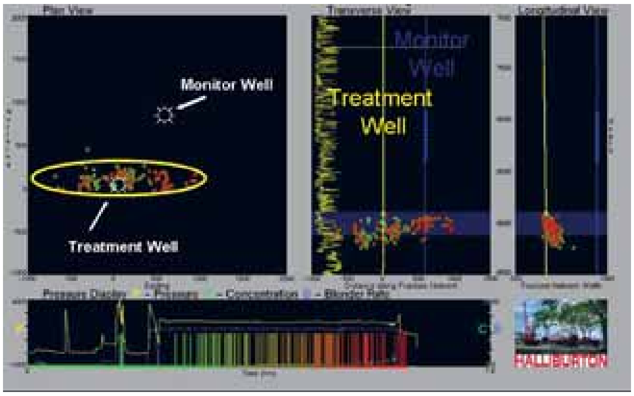

***Figure 1** Stage one of a monitoring service for the Jurassic Sandstone ArkLaTx region of the US indicating a near symmetrical bi-wing fracture propagation with an east-west azimuth.*

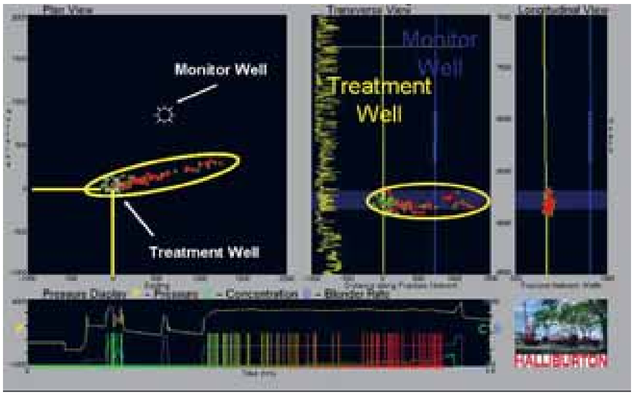

***Figure 2** Stage two of the monitoring service for the Jurassic Sandstone ArkLaTx region indicating single wing fracture propagation in an east-northeast direction (N 60 E).*

Improving reservoir understanding
Micro-seismic monitoring of a pair of multi-zone treatment wells provided the operator with data to identify future well locations for optimal reservoir recovery. Mapping out-of-zone fracture height between successive stages enabled identification of fractures or fault planes in the reservoir. The two wells were drilled in a basin with thousands of feet of inter-bedded sandstone and shale sequences. The sandstones are lenticular in nature and can be difficult to correlate well-to-well. A simple geological explanation is to picture the sand bodies as stacked ellipsoids with a random axis of symmetry with respect to the wellbore.

The mapping of the stimulation treatments (Figure 3, plan view) indicates asymmetrical fracture wings. The fracture geometry in these stratigraphic deposits described the lateral extent of the sand lenses from the wellbore along the strike of the fracture azimuth. The fracture height is correlated with the thickness of the sand members. Drilling-

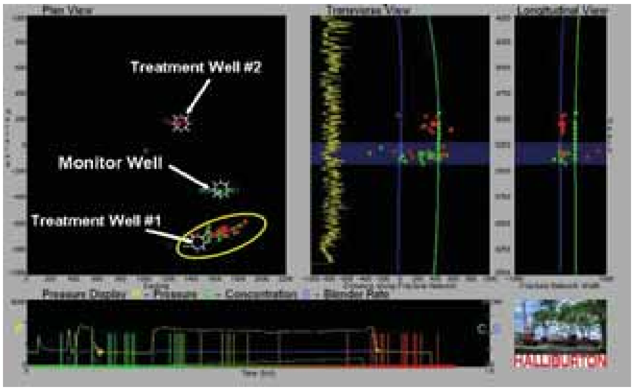

Figure 3 *Fracture geometry service indicating an axis of stratigraphic sandstones with respect to the wellbore.*

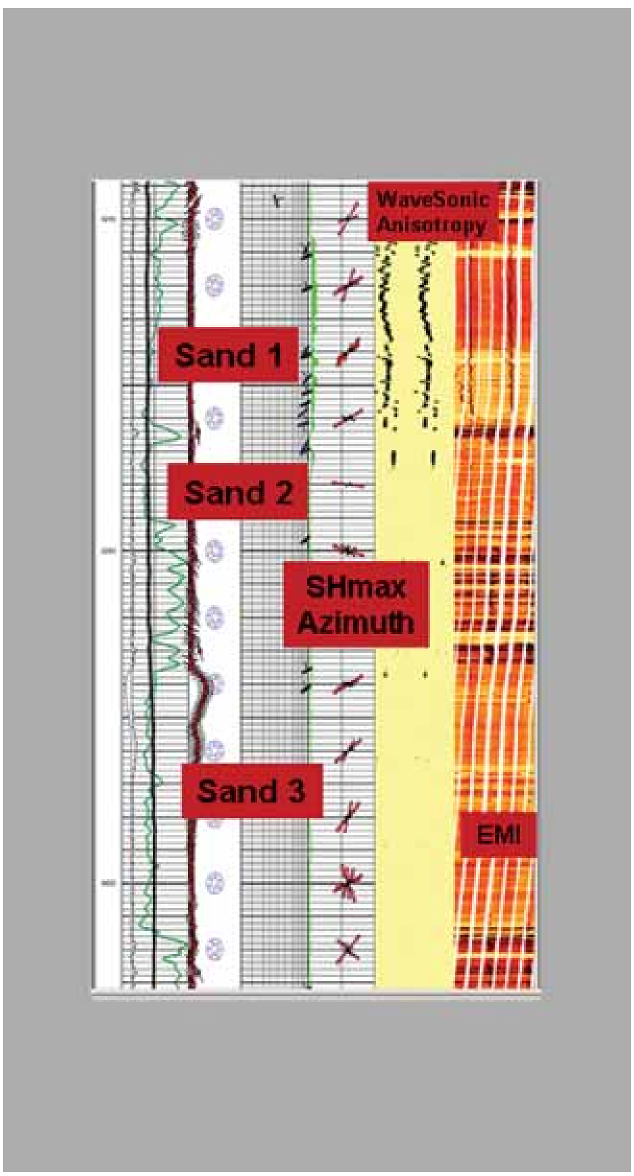

Figure 4 *Drilling induced fractures identified in Sand 1 by anisotropy analysis service and tool.*

induced natural fractures were identified from wave sonic anisotropy analysis while electromagnetic imaging was used to spot sandstones of lower reservoir pressure. In formations with a constant Poisson's ratio, a pressure-depleted region will have a lower stress than a region at virgin reservoir pressure, and hydraulic fracture will propagate towards the lower stress regions.

As shown in Figure 4, Sand 1 exhibits drilling induced fractures, while Sands 2 and 3 do not. Effective stimulation required that each of the three sands be fractured in discrete stages. If all three were to be simultaneously fractured, essentially only Sand 1 would be treated, since it has a lower maximum horizontal stress than the Sand 2 and 3 zones.

Figure 3 shows micro-seismic mapping of the stimulation treatment for Sand 2. The blue shaded region in the transverse view defines the formation boundaries of Sand 2. There is some upward fracture propagation from Sand 2 into Sand 1 shown by the micro-seismic events in the transverse view. In the asset view, system mapping of the many stimulation stages provides a 3D picture of the reservoir and the fracture drainage patterns for identification of future well placement locations.

Asymmetrical fracture propagation

A US tight gas infill drilling programme benefited from micro-seismic data that showed unstimulated areas for future wells, and provided out-of-zone data for improving the frac design. Monitoring of the multi-stage hydraulic stimulation treatment was done in a horizontal well located in a major Jurassic age tight gas formation in the ArkLaTex region.

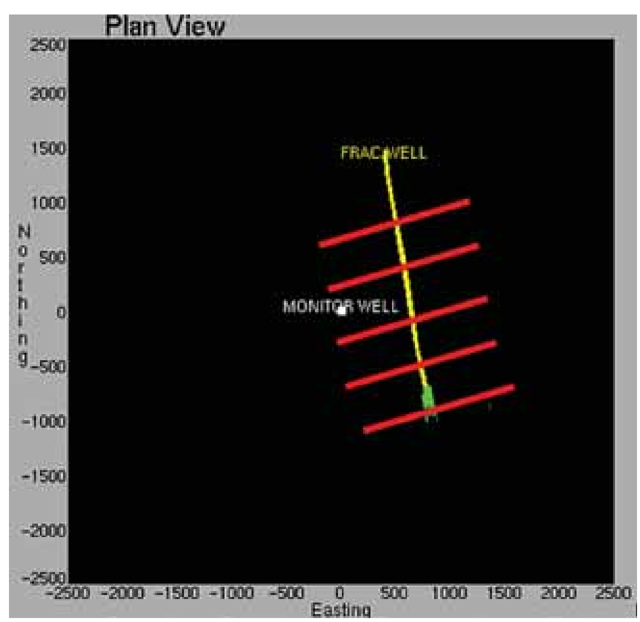

Figure 5 *Proposed five-stage fracturing of the infill drilled horizontal well.*

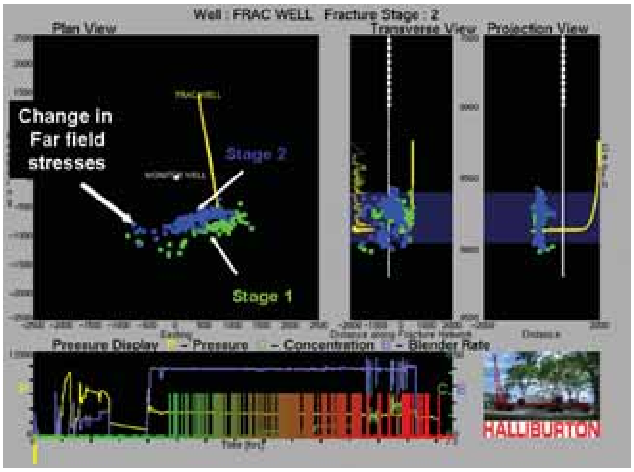

Figure 6 *Mapping service of stages one and two.*

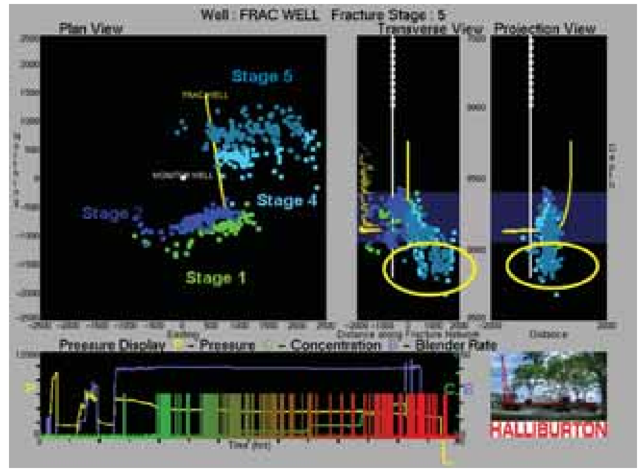

Figure 7 *Mapping service of stages one, two, four, and five.*

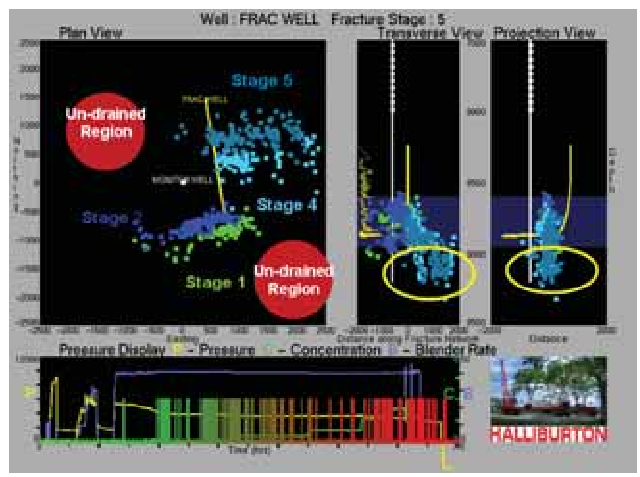

Figure 8 *Identification of undrained regions and possible infill drilling locations.*

The low-permeability sandstone formations in this region have an extremely large lateral extent, and from geomechanical analysis these sands have near constant Poisson's ratio. Orientation of the reservoir's existing hydraulic fracture systems and their corresponding drainage patterns from existing well bores were not known prior to the infill drilling programme. The near real-time micro-seismic mapping and display of fracture propagation in large scale reservoirs can identify fracture propagation toward previously drained regions of the reservoir through observation of asymmetrical fracture geometry. Identifying these features in near real time facilitates early termination of a treatment into a previously drain region, which is a cost savings to the operator and provides data for 3D reservoir modelling.

The system mapping of stage one (green) shows near symmetrical bi-wing fracture propagation at the toe of the treatment well with a fracture azimuth of approximately N 80º E (Figure 6). Stage two (blue) exhibits a near single-wing fracture with a fracture azimuth similar to stage one. On the westerly tips of the fractures in stages one and two there is a change in the fracture azimuth to the northwest. This change is a result of far-field stress changes in the reservoir attributed to changes in pore pressure. In the transverse view, there is minimal out-of-zonal growth for both stage one and two.

Mapping of stages four and five indicates single-wing fracture propagation in a near easterly direction away from the monitor well (Figure 7). The yellow ellipse region in the transverse view and projection view of Figure 7 indicates downward fracture propagation into a probable pressure-depleted sand below the horizontal well trajectory.

The micro-seismic mapping of the fracture propagation and its associated drainage patterns in the vicinity of the horizontal well identified two regions for possible infill drilling locations (Figure 8). The red circles in the upper left and lower right of the plan view identify areas not associated with fracture propagation or drainage.

Summary

Advances in micro-seismic mapping technology are providing a growing range of benefits for maximizing production from unconventional reservoirs. Accurate, reliable data is helping operators fine-tune frac models and maximize reservoir drainage. Real-time fracture mapping enables on-the-fly changes in fracture design to maximize the effectiveness of a stimulation treatment.

The benefits of facture mapping are enhanced by Halliburton's ExactFracsystem, the system described here, as part of its holistic Digital Asset service model. The model is a true integration of people, processes and technology, resulting in an empowered workforce that is able to see the big picture, make fully-informed decisions, and operate more efficiently and effectively. As a result, E&P companies are able to achieve greater accuracy in less time, allowing them to drill and stimulate wells more effectively and with less non-productive time.