X MARKS THE SPOT

Adam Baig, Sheri Bowman and Katie Jeziorski, ESG Solutions, explain how microseismic monitoring has evolved to become more than just mapping fractures.

Hydraulic fracture stimulation has become a widely applied technique to exploit hydrocarbon reservoirs with low natural permeability. Although the technology was introduced more than 60 years ago, the recent growth of horizontal well and pad drilling technology, multi-stage fracturing and improved seismic surveillance have dramatically increased production economics for hydraulic fracturing, making the method much more appealing to operators across North America.

In unconventional reservoirs, well production success depends on a number of factors. A key aspect is whether the well has been optimally drilled within productive zones, or so called 'sweet-spots.' Following well placement, effective stimulation of the desired pay zone depends not only on the successful generation of complex fracture networks, but whether there exists good connection pathways from the reservoir to the production well. Often, complex fracture networks are achieved through activation of existing natural fractures, rather than the generation of new fractures. It is therefore useful to accurately characterise these natural fracture systems and understand fracture behaviour within the formation in order to optimise drilling and completions designs.

Microseismic, or passive seismic monitoring has emerged as a powerful fracture characterisation and production optimisation tool for hydraulic fracturing operations. Unlike large-scale earthquakes, which can be felt on the surface, microseismic events are very small and usually range from -4 to 0 on the magnitude scale. Microseismic events are caused by changing stress conditions in a formation during high-pressure fluid injections that cause failures and shear slippage along existing weaknesses in the rock. These failures release acoustic energy that can be detected with sensitive monitoring equipment positioned near the production zone.

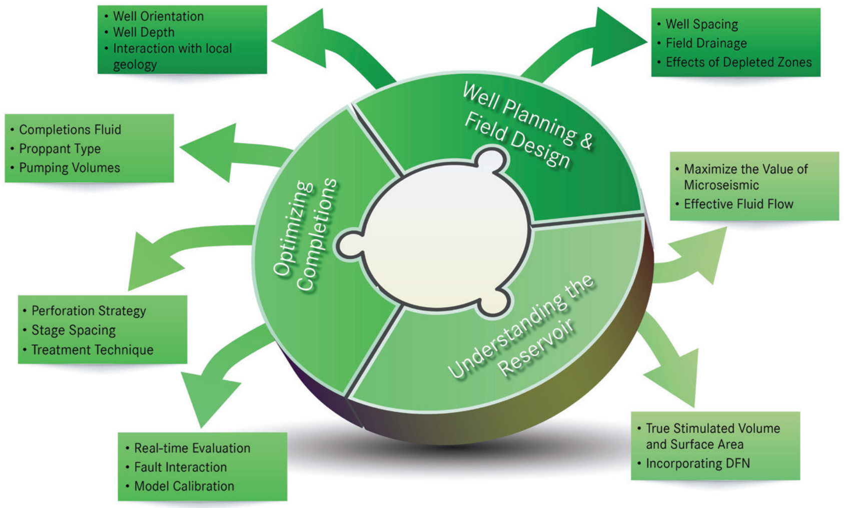


Figure 1. *Microseismic methods have a wide range of applications to help improve production from unconventional reservoirs including well and field planning, completion optimisation and reservoir characterisation.*

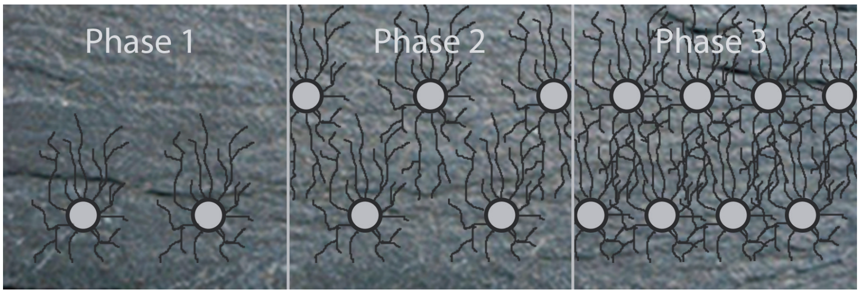


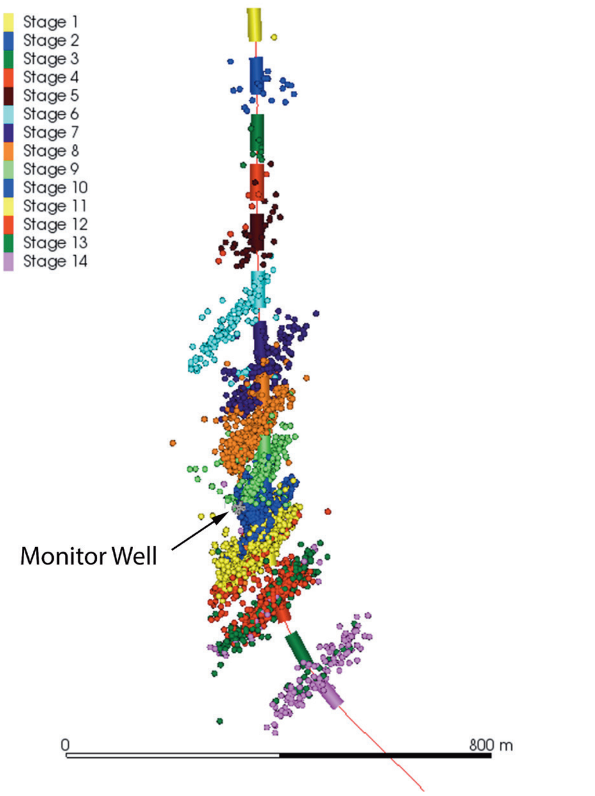
Figure 2. *Example of a phased approach to optimising well spacing in an unconventional reservoir.*

Typically, sensor arrays of triaxial geophones are deployed downhole in nearby observation wells, on the surface in near-surface arrays, or a combination of both (hybrid) to 'listen' to the microseismic activity. Detection, location and visualisation of these microseismic events provide a continuous, image of underground fracture propagation.

When ESG's FRACMAP® service was launched in 2000, mapping fracture dimensions for individual stages was the primary goal of microseismic hydraulic fracture monitoring. Since then, technological advances in computing and monitoring equipment, along with changes in the industry have transformed microseismic services into something quite unrecognisable. A strong focus on data integration between geophysical, geological and engineering sources continues to unlock new ways to interpret microseismic results beyond simply plotting event locations on a map.

Microseismic fracture monitoring solutions provide feedback to engineers and geoscientists on the success of their operations at various stages of field development (Figure 1). For example, microseismic results can be used to refine reservoir models or assist with reservoir characterisation, helping to optimise well position and spacing within a field. Evaluation of seismicity generated during different completions methods enables a direct comparison of techniques and technologies to identify the optimal treatment design for a given formation layer. Assessment of microseismicity within the context of a developed fracture network and connection pathways to the well contribute to estimates of stimulated reservoir volume (SRV) and expected production volumes.

Regardless of the application, microseismic results provide yet another tool in the quest to maximise recovery from complex unconventional plays.



Microseismic events recorded during a 14 stage horizontal fracture stimulation. *Events are coloured by stage.*

Well and field planning

At a basic level, visualisation of microseismic event locations provides a cursory indication of stimulation success, and is commonly used in well planning and field design. Measurements of fracture azimuth and half-length are readily used to adjust well orientation and spacing within a field. In formations with multiple stacked zones or presumed fracture barriers, observed fracture height may help determine the optimal depth to land a lateral well. Over time, microseismic results may be used to evaluate downspacing schemes (Figure 2) for optimal field development. As production in unconventional formations matures and operators are no longer concerned with drilling to maintain leases, infill wells may be added to properties with existing wells on production. When treating infill wells, the presence of nearby depleted zones may pose challenges for operators, as fracture fluid can migrate into open fracture networks surrounding previously treated wells rather than stimulating the target zone. Patterns in seismicity, including event clustering, out-of-zone events or a conspicuous lack of seismicity where it would otherwise be expected, may help diagnose fluid communication between treatment wells and depleted zones, assisting in the optimal placement of these infill wells.

Optimising completions

Completions evaluation begins with an assessment of whether all aspects of a hydraulic fracture treatment were executed as planned; namely, was each stage successfully initiated in the correct zone? Were the fracture fluid and proppant able to generate and maintain a complex fracture network within the target zone? And was this fracture network well connected to the production well? Traditional plug-and-perf completions make use of a cased well and a sequence of perforations to define individual stages for treatment along the well. Perforation shots are easily detected by microseismic equipment, enabling clear assessment of fracture initiation at each stage. Continued real time monitoring of fracture development during the treatment may also provide warning of unexpected behaviour or interaction with geohazards, which could compromise operations.

Completions methods using open-hole wells equipped with sliding sleeve fracture ports are also gaining in popularity for their associated cost savings. Once installed, sliding sleeve fracture ports are activated using a series of different sized balls inserted into the well. Each ball is pumped into the well and comes to a rest at the target, where an increase in pressure stimulates the sliding sleeve and opens the fracture port. Microseismic monitoring of open-hole completion programmes often observes characteristic seismic signals following the addition of a ball into the well. These seismic signals are referred to as 'ball-seat events' and help evaluate the success of the completion or diagnose unexpected fracture development related to problems with stage isolation.

In an example of an open-hole completion, ESG acquired and processed microseismic data from a 14-stage horizontal sliding sleeve hydraulic fracture programme in a North American tight-oil play using a 16-level vertical geophone array. The operators were interested in observing fracture behaviour, in order to optimise well position and completion design for subsequent wells in the same field. Observed microseismic results are provided in Figure 3.

Most stages exhibited a consistent fracture azimuth close to 45˚, suggesting that the well was not drilled perpendicular to the maximum principle stress. Near the heel of the well, seismicity recorded during stages 12 and 13 (red and green dots in Figure 3) overlapped significantly, and was accompanied by a conspicuous region of minimal seismicity within the stage 13 zone (Figure 4A). A detection bias due to distance from the monitor well was ruled out as the cause of the lack of seismicity in the stage 13 zone. As previously described, ball seats during sliding sleeve completions have distinctive seismic signatures. Ball seat signals for stages 12 and 13 were detected and located in the stage 12 zone (Figure 4B) suggesting that an error occurred with the activation of the sliding sleeve for stage 13. This error caused the stage 12 zone to be stimulated twice, while bypassing the stage 13 zone completely. If the programme had been monitored in real time, the error with the stage 13 ball seat may have been recognised and remedied to avoid bypassing the zone, or at the very least avoid wasting valuable time and materials associated with re-stimulating stage 12.

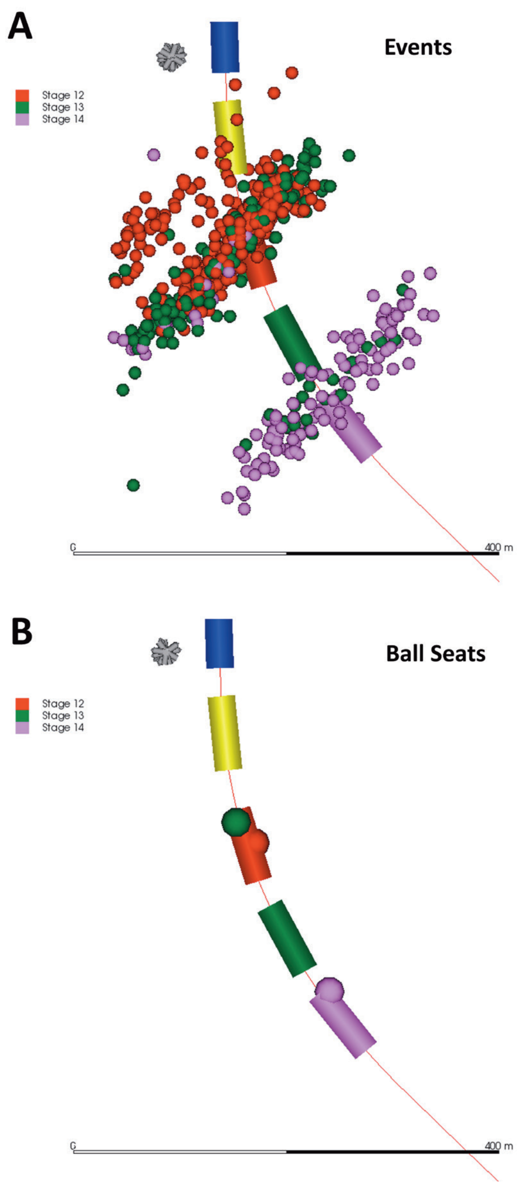


Figure 4. *Seismicity observed during stages 12 - 14 (A) and the location of ball seats associated with the same stages during the completion (B).*

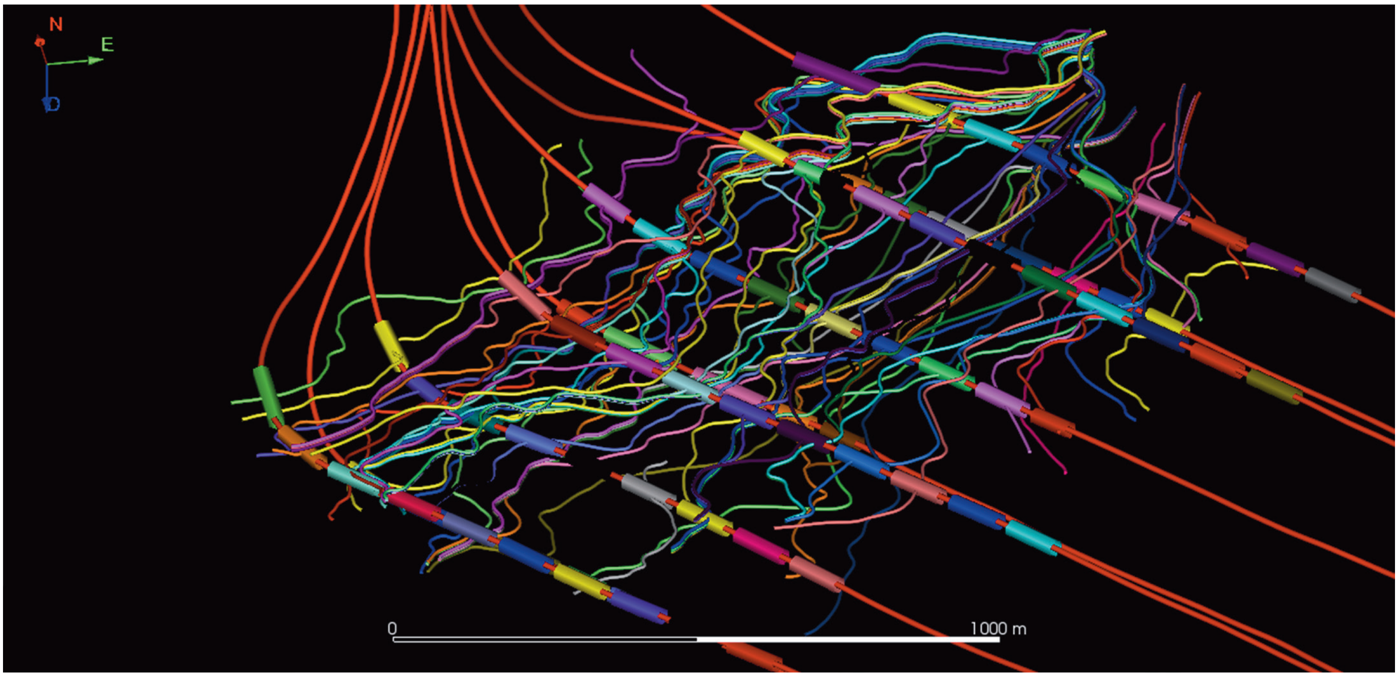
Understanding the reservoir

In hydraulic fracturing operations, achieving maximum production along an entire well depends not only on effective well placement and completions design, but also on the inherent characteristics of the reservoir including the mineral makeup of the rock, local and regional stress conditions and the presence of natural fracture networks. Ideally, completions designs are tailored to the specific reservoir conditions, however considerable formation heterogeneity coupled with a poor understanding of the subsurface are often cited as key challenges for producers in maximising production from hydraulic fracture stimulations. In many instances where wells were treated identically, operators across North America have demonstrated cases where hydrocarbon production rates vary not only between wells in the same field, but between stages along the same well.

Perhaps the least recognised, but potentially most powerful application of microseismic monitoring relates to the ability to use information contained within the full seismic signals to improve understanding of reservoir conditions, reservoir behaviour and fracture development processes. To achieve this level of detail, advanced microseismic processing methods are applied to high-quality multi-array microseismic data. Integration with existing reservoir modelling platforms means that operators can combine such microseismic information with other geophysical and geological data sources to guide decision processes.

Fuelling much of the development of advanced microseismic analysis has been new, multi-array microseismic sensor deployments. Multiple geophone arrays are now routinely deployed in a number of vertical or horizontal wells on a site, or complimented by near-surface buried arrays. The rise of pad drilling provides considerably more options for downhole monitoring, making use of adjacent laterals as temporary observation wells while innovative approaches such as the whip-array further support multi-array monitoring by functioning as two geophone arrays deployed into the same lateral. Multi-array deployments considerably improve the quality and quantity of microseismic data, and enable advanced geophysical analysis to distinguish how rock failures occurred, evaluate stress conditions in the vicinity of the failure, establish discrete fracture network (DFN) models and determine whether effective flow pathways have been created.

A key advanced processing technique that has emerged within the microseismic industry and is driving much of the recent innovation in



Modelling reservoir drainage pathways using a microseismic-based discrete fracture network (DFN) and knowledge of local stresses helps evaluate drainage potential across lithological units.

understanding reservoir behaviour is seismic moment tensor inversion (SMTI). A well established method in the field of earthquake seismology, SMTI may be applied to microseismic data to connect seismic observations to physical processes at the source. SMTI analysis reveals the event failure mechanism, principle strain axes and potential failure orientations. Evaluating event failure mechanisms is a key aspect to understanding how the treatment programmes will improve the drainage characteristics of the reservoir. Each microseismic event can be viewed as failure in shear, tensile opening/closing or some combination thereof. The failure occurs on a fracture plane (strike and dip) of a certain size that is itself, part of a network of new or pre-existing fractures. Therefore, microseismic event distributions can be used to reconstruct the DFN that is activating in response to the stimulation program. Coupled with the dimensions of the failure planes, fracture orientations inferred from the moment tensor can generate an activated DFN model.

During the generation of this DFN, it is imperative that values such as fracture length be accurately characterised, particularly for larger magnitude events. In faulted formations, it is not uncommon to observe some events that measure above zero on the magnitude scale. Naturally, larger events release more energy and will be related to failure along a longer fracture surface. It has become well known in the industry that typical microseismic equipment, namely 15 Hz geophones, may underestimate these values; therefore the incorporation of 4.5 Hz geophones and force-balanced accelerometers (FBAs) that are tuned for the low frequency characteristics of larger magnitude events in ESG's hybrid approach may offer increased accuracy in characterising fracture networks across a range of scales.

Describing fracture processes in the context of production

Microseismicity may be fluid-induced or it may be caused by changing stress conditions in the reservoir, therefore not all seismicity will contribute to production. Development of a microseismic-based DFN model can describe fracture networks that have been activated during stimulation, but further interpretation is required to determine how these fractures will impact reservoir drainage. This interpretation starts with an examination of stimulated reservoir volume (SRV).

Estimates of SRVs have evolved over the lifetime of the technology. Early attempts to define SRV by using envelope functions around microseismic event distributions generally resulted in large overestimates of the stimulated zone by incorrectly accounting for outlier events and an inability to distinguish between fluid-induced and stress induced events. Further refining SRV to an estimate of the most seismically deformed volume addressed the issue of outliers, but does not incorporate knowledge of failure mechanisms or activated fracture sets. By considering that stimulated fractures can form a number of intersections the stimulated volume can be interpreted in terms of fracture complexity (FC).

A final consideration to the stimulated reservoir volume is to determine where fracture complexity allows for a part of the reservoir to be well connected back to the perforations, in essence providing a drainage pathway. Using advanced SMTI analysis, high-quality events can be inverted for a general solution, which enables determination of whether mixed-mode shear-tensile events exhibit fracture opening or closing components. With reference to a geomechanical model, the amount of net opening within the fracture networks defines a volume of enhanced fluid flow (EFF) in the reservoir. By evaluating the orientation, density and size of fractures as they intersect within the fracture network, it is possible to better delineate drainage pathways within the reservoir. Using a geomechanical model of strain imparted on the rock mass, stream lines are developed to visualise fluid flow paths with seed points at individual stimulation ports (Figure 5). Overlying this analysis with calculated seismic deformation and fracture complexity within the reservoir then provides some indication of reservoir drainage.

Microseismic methods can offer key insight during all phases of well-planning and completion. The microseismic industry has come a long way over the last 15 years, both as an accepted technology and also as a comprehensive geophysical service that offers more than just mapping fractures. New and emerging advanced methods continue to discern more information about reservoir makeup/conditions and fracture network generation, giving engineers and geoscientists the information they need to maximise production in challenging formations.