

Microseismic Monitoring for Unconventional Resource Development

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Abstract

Microseismic monitoring of hydraulic fracture well treatments is an important enabler of shale reservoir development. Hypocenter location of the fracture events can be accomplished with travel time inversion techniques or full waveform migration techniques. The former usually require that the geophones be placed at near reservoir depths. The latter require large surface or near surface arrays. Focal mechanism analysis of the microseismic events can be used to increase the understanding of the reservoir properties. Application of the technology to other types of reservoirs and other development problems is likely.

Introduction

We are indeed fortunate to be living through a resurgence of the oil and gas industry, an event being termed the "Shale Gale". Oil and natural gas production rates in the United States have begun to climb again after years of decline. Operators are moving aggressively to export this storm of discovery to shale basins around the world.

The success in the shales has been driven by technology not geology. We have known about the shales for decades and dutifully noted the hydrocarbon shows we observed as we drilled through those shales to more permeable and producible reservoirs. The technologies that have enabled this success are three. First is horizontal drilling. Long reach laterals, often as much as 4000m long, provide unprecedented access to the reservoir and allow for flow volumes that make the shale plays economic. The second technology is hydraulic fracturing. Not a new technology, frac'ing has been around since 1947 when it was first tried by Stanolind in the Hugoton Field, Kansas, USA. It is estimated that more than 2.5 million wells have been frac'ed since then and that the increased reserves attributable to this technology in the US alone amount 9 billion barrels of oil and 700 tscf of natural gas. As much as 60% of the wells completed today require some form of frac'ing.

The third enabling technology is microseismic monitoring. Before monitoring became common, the numerical tools available to engineers for modelling their fracs were rather simplistic. Frac's were assumed to be bi-wing, symmetric, vertical planar features. Government sponsored experiments where rocks were mined to expose the actual fracture patterns showed that fractures are much more complex. Microseismic monitoring has now been accepted as a tool that can reveal that complexity, producing maps of the actual fractures even in near real time, as they are created. As many as 5% of the hydraulic fracture treatments performed in the US are now monitored, with some operators

opting to monitor every well as they develop their field. The number of stages monitored is likely up by 300% in the last 2 years and continues to grow.

Driving the increased penetration of this technology is an appreciation of the complexity of shales. The earlier assumption that one could get away with monitoring the first couple of wells in a field and then expect everything to remain the same thereafter has proven to be a poor one. The response of the rocks is seen to vary from well to well and stage to stage. The response to pumping has also been observed to change over time as production changes the local stress distribution in the rock.

Method

Acquisition

There are 3 predominant approaches to acquiring microseismic data during hydraulic fracturing operations. The legacy technique uses strings of 3-component geophones placed in wellbores at near-reservoir depths. (Maxwell et al., 2010) The geophones are placed in monitor wells that must be cleaned out and shut in during the monitoring. Anywhere from 6 to 99 geophone levels in a single monitor well may be deployed, typically at intervals of 10 to 25 m using a wireline system (see Figure 1). Attenuation of the signal limits how far a monitor well can be from the treatment point and still adequately detect signal. Imaging errors related to the length of the geophone string also limit how far a useful monitor well can be away from the treatment well. Occasionally more than 1 and as many as 4 monitor wells are used in order to remove some of the geometrical uncertainties, and to allow for the monitoring of a large treatment area.

In the last 6 years another approach to acquiring the data using surface phones has gained traction in the marketplace. A large spread of geophones is laid on the surface, much like a 3-D patch. (Duncan and Eisner, 2010)

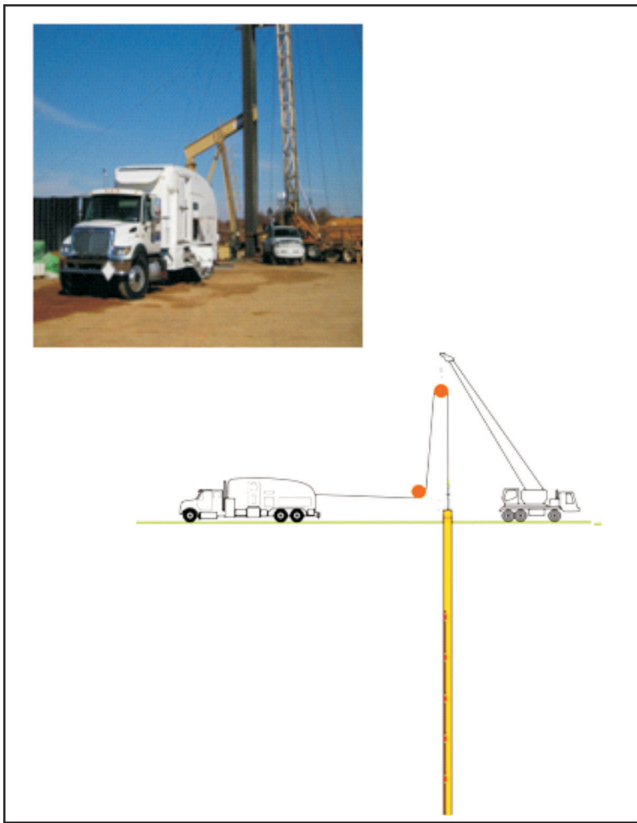


Fig. 1: Cartoon of the wireline deployment of a string of geophones in a monitoring well as well as a photograph of an actual deployment. The geophone string will typically be deployed at near-reservoir depths subject to pressure and temperature limitations.

One embodiment of this approach is shown in Figure 2. The vertical component phones are laid out in a radially symmetric pattern around the treatment wellhead. The radius of the pattern is made about equal to the depth of the deepest treatment zone. Typically as many as 1000 groups of

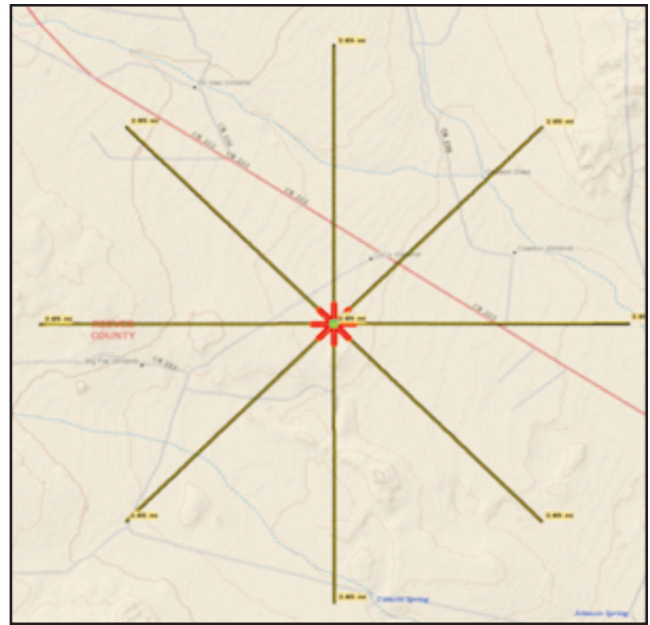


Fig. 2: Map view of a FracStar® surface monitoring array. The treatment well head is at the center of the array. Lines of vertical geophone strings are laid out along the radial arms, usually 6 to 24 phones per group with a group interval on the order of 31 m. The radial arms have a length about equal to the target depth.

6 to 24 phones each are required to overcome the low signal to noise ratios experienced during frac'ing operations.

The third acquisition technique has arisen largely for economic reasons. Drilling a well solely for the purposes of monitoring a well treatment is an expensive proposition. Rarely is a well that already exists in just the right location to act as a monitor well, particularly with long laterals and multi-well pads really requiring that you have multiple monitoring wells. The surface arrays can monitor large areas, but if the

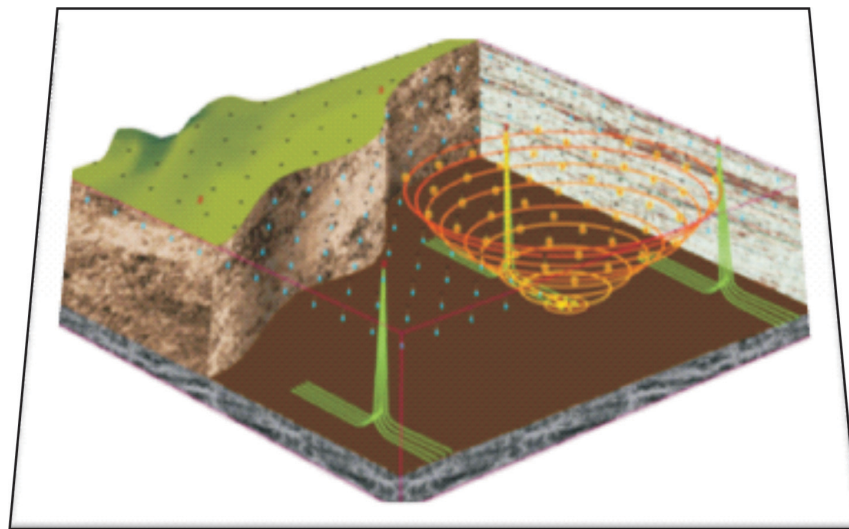


Fig. 3: Schematic representation of a "life of field" buried array. The blue dots represent the station locations. At each station a multi-element phone is cemented at about 100 m. depth. The diagram depicts several multi well pads with several laterals drilled from each. The expanding circles represent the microseismic signal emanating from a treatment point on one of the wells.

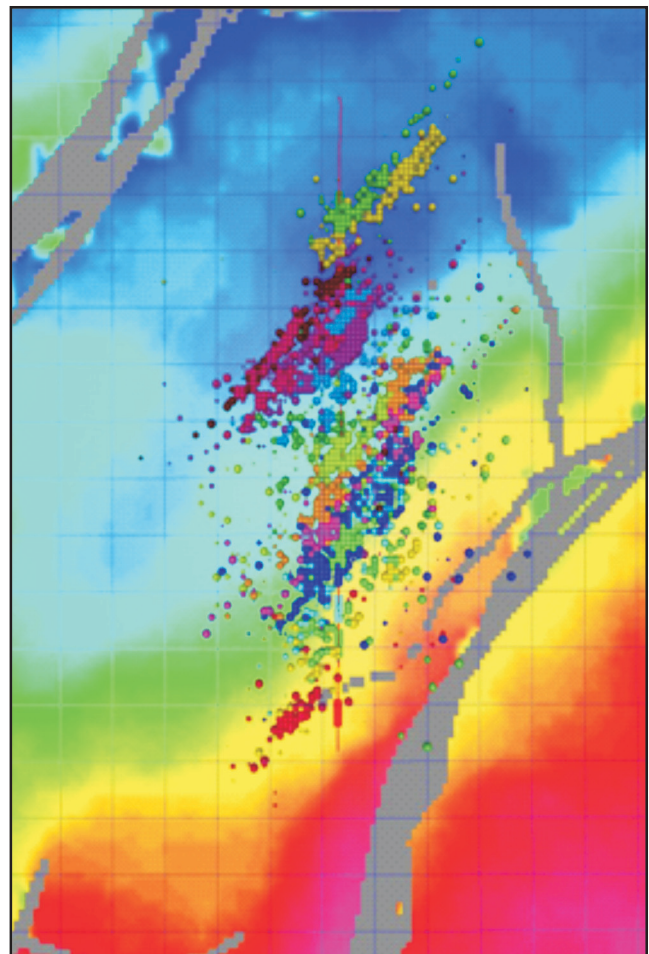
surface is heavily treed or topographically challenging, then mobilization and demobilization charges can be considerable. Finally, as operators have begun to appreciate the need to monitor more and more of the wells in any give field development, they have been seeking ways to monitor these wells at a lower unit cost. This has led to the deployment of permanent monitoring arrays (see Figure 3) that can be used to cost effectively monitor most if not all the fracturing operations as the field is developed at a very low incremental cost. The geophones are cemented in shallow holes usually at depths on the order of 100 m or less. By placing the holes away from the noisy free surface of the earth, a much lower fold of observation is required to achieve a sufficient signal-to-noise ratio. Station spacings of 1000 m are common with the arrays being designed with a target fold on the order of 100. These observation stations are too far apart to be connected by wires, therefore some sort of wireless telemetry or manual collection of the data (a "sneaker net") is employed for data retrieval.

Analysis

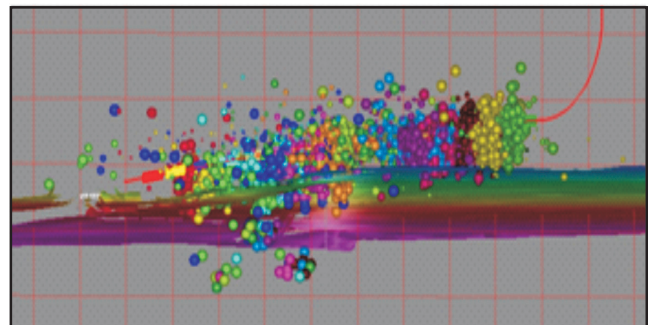
In the first place, analysis of monitoring data aims to estimate the hypocenters of the events created as the rocks fail during the hydraulic fracturing treatment. That is, to pinpoint in time and space where and when the fractures occur in relation to the treatment well and the pumping process. In a very real way this is equivalent to locating the hypocenter of a naturally occurring earthquake, excepting that these events are very much smaller than the earthquakes typically tracked by government and academic research organizations. The local magnitude (ML) of events observed during hydro frac'ing is usually less than -1. This is 3 orders of magnitude smaller than can be felt at the earth's surface. The smallness of the signals is key to the techniques that have been developed to process and analyse microseismic data.

The standard practice for locating earthquakes is to pick the arrival time of the P and S phases of the events at an areal distribution of stations. A trilateration technique (travel time inversion) applied to these observations allows for an estimate of the event location. As well, if the tilt of the direct arrival wavefront can be estimated by using 3-component geophones through some form of hodogram analysis, then an estimate of the hypocenter can be obtained from even a single observation station, or alternatively, multiple stations can be used in a triangulation approach. (Maxwell et al., 2010).

In the case of microseismic events, the small magnitude makes precise picking of arrival times and wavefront dips problematic at the surface. This fact is what led to deploying the geophones close to the treatment point in a nearby monitor well. The need for multiple observation points to affect either trilateration or triangulation is usually met with multiple geophones in a single well rather than the



(a)



(b)

Fig. 4: Map (a) and westward looking section (b) view of the results of a surface microseismic monitoring of the treatment of a well in southern Texas. The grid is 500 ft (152 m.) on a side. The well is represented by the solid red line. Colored hatchings along the well represent the different perforation intervals that were successively treated from the toe to the heel of the well. The colored balls represent the estimated hypocenters of the mapped microseismic events, colored to match the stage with which they are associated. The color contours represent the depth of the base of the reservoir interval being treated. The map view (a) also shows fault intersections with the horizon as grey zones.

more expensive option of multiple phones in multiple wells distributed around the treatment well. The loss of aperture when using a single observation well is a limiting factor in

the usefulness of the downhole monitoring technique. (Eisner et al., 2009)

An alternative to travel time inversion is to use some form of full waveform migration (Duncan and Eisner, 2010). In this approach the observed wavefield is extrapolated from the observation points backward in time to the source point. This approach requires a well sampled wavefield over a large aperture and is more easily accomplished by a surface or near surface array. It should be clear that the signal-to-noise requirements of the arrival time picking source location technique dictate a downhole approach to data acquisition, while the aperture requirements of the migration approach to source point imaging dictate a surface or near surface approach to data acquisition.

The result of either approach is a time varying map of event locations (see Figure 4). At the individual well level, such results can be used to detect mechanical failures in the treatment (packer or cement failures leading to repeated treatment of the same intervals at the expense of other intervals along the wellbore), to detect geologic failures (particularly reactivation of pre-existing faults that become

thief zones of the frac treatment effectively blunting the usefulness of the frac or, worse, resulting in fracturing into local water bearing zones causing costly water remediation problems), and to judge the effectiveness of the chosen pumping parameters so as to make adjustments for future stages or wells. Usually the areal distribution of events is used to make a estimate (often rather gross) of the stimulated reservoir volume (SRV) associated with the well treatment, in other words an estimate of the drainage area associated with the treated well or assemblage of wells in the case of a multi-well pad. These hypocenter location results, whether presented as maps, sections or movies we often refer to as the "dots in the box" result.

Beyond the Dots in the Box

The recognition that the microseismic events are really the result of microearthquakes leads to the realization that these events not only have an origin in time and space but also have a sense of motion (failure mechanism) and a magnitude (Williams-Stroud et al., 2010). Both of these can be estimated if a sufficient sample of the signal wavefront is obtained such that the radiation pattern can be mapped (Šílený et al, 2009) . The surface and near surface arrays are

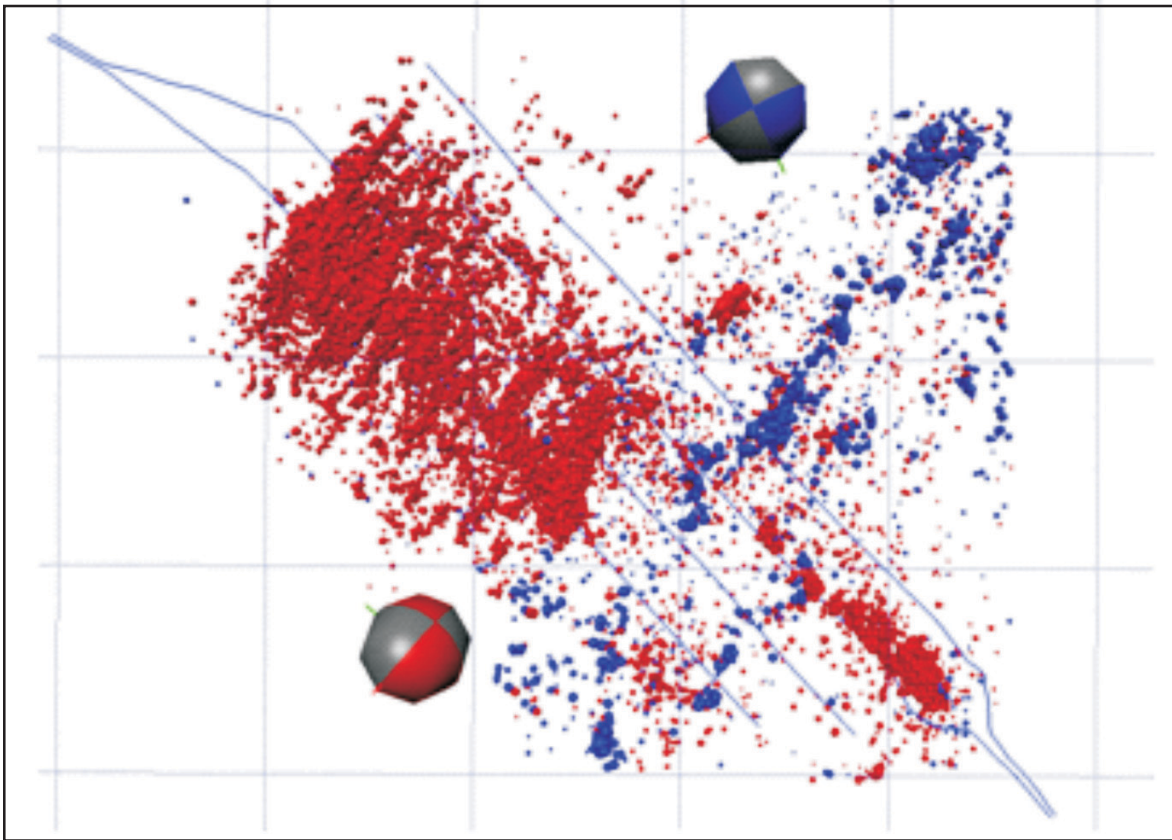


Fig. 5: Map view of surface microseismic monitoring results for the treatment of a 4 well grouping in Texas. The displayed grid has dimensions of 1000 ft (305 m) on each side. The colored balls represent the hypocenters of the events detected during monitoring, colored by the failure mechanism of the event. The "beach ball" icons represent the lower half plane projection of the radiation pattern detected for each event, from which the failure mechanism was deduced, grey for rarefaction and colored for compression. The red events are predominantly dip-slip with an interpreted near vertical failure plane, the blue are strike-slip, again with a near vertical failure plane. The blue events appear to represent the reactivation of a relatively major regional fault that intersected the wells. (Wessels et al., 2011)

particular well suited to this requirement owing to their large aperture. If the failure mechanism and magnitude can be estimated, they provide fundamental information about the type of failure, the orientation of the failure plane, the size of the fractures created and the local stress regime at the point of failure. (Wessels et al., 2011) This in turn leads to a better understanding of how the reservoir will perform as a result of the frac'ing. Figure 5 presents a graphic example of how these mechanisms can come to play an important role in microseismic data analysis.

Taking this analysis further, one can use the temporal and spatial distribution of events, their failure mechanism, and any other external constraining observations, to begin replacing the "dots" with estimates of the fracture planes that created the microseismic events as depicted in Figure 6. With an assignment of permeability, the fracture model (Discrete Fracture Network or DFN) can be upscaled to a grid model that then can be used in a reservoir production simulation model to begin predicting well and field performance (Williams-Stroud et al., 2010). History matching to actual production provides feedback to the model allowing for improved parameter selection. As the number of wells monitored in the field increases, it becomes possible to further refine and improve the process just outlined. The goal is to give the operator a better handle on optimal well orientation, infill spacing, estimated ultimate recovery (EUR) and recompletion potential.

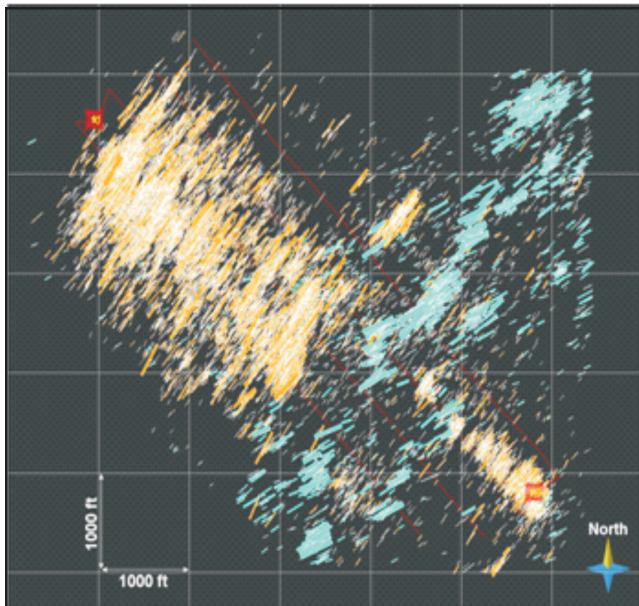


Fig. 6: A Discrete Fracture Network (DFN) estimated from the microseismic events displayed in Figure 5. A statistical process was used to estimate the fracture location and sizes driven by the number and magnitude of detected events. The fracture orientations were constrained by the failure mechanisms determined for the events. The blue planes represent fracture associated with the strike-slip mechanism seen in Figure 5 while the yellow fractures were derived from the dip-slip (red) events.

Conclusion

While the practice of microseismic monitoring is decades old, the practical application of the technology on a large scale is relatively recent. As our experience in the field grows we are only beginning to understand the knowledge that can be extracted from these data and the impact it can have on field production and development. As our understanding of the technique grows, I would expect the application to extend beyond frac monitoring to become more prevalent in such areas as steam injection monitoring in heavy oils, gas and water injection monitoring for enhanced recovery, CO2 sequestration monitoring and perhaps even monitoring of the reservoir under normal producing conditions to track hydrocarbon flow. There is much yet to be done.

References

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