Microseismic Data

BEYOND FRAC MONITORING

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The Oil and Gas industry is experiencing a resurgence of hydrocarbon production in North America stimulated by application of hydraulic fracturing (frac'ing) and long horizontal well drilling in regionally extensive unconventional shale basins. Frac'ing has permitted extraction of previously uneconomic oil and gas resources through the application of low cost, high volume procedures developed specifically for unconventional resource development. The technique, originating in the mid-20th century and refined in the last 10 years for shale stimulation, attempts to connect subsurface rock fracture networks in low permeability, hydrocarbon-bearing formations. To maximize recovery field wide, operators must optimize the balance between volume of fluid and proppant pumped with the volume of reservoir contacted. Microseismic monitoring has emerged as a key technology for well stimulation to show the 3-D extent of fracture growth; but microseismic monitoring can be used for much more.

Microseismic monitoring was introduced in the 1970s but not fully commercialized until the early 21st century. This passive seismic technique is used to detect slip along naturally occurring fractures occurring due to minute changes in stress in the subsurface resulting from natural and anthropogenic activity. Widespread commercial adoption of the technology has been primarily for fracture mapping. The technology can and has been applied to other subsurface monitoring requirements including; reservoir production, detection of upward migration of injected steam, subsidence related to depletion, cap rock integrity, mapping fluid migration pathways in the reservoir and prediction/detection of casing failure. Finally, microseismic monitoring is well suited to detect infrequent anthropogenically induced seismicity that may occur near wastewater injection or from hydraulic fracturing processes.

Understanding Microseismic Acquisition and Processing

There are two prevailing processing techniques for locating microseismic events. Downhole monitoring employs a string of geophones placed in a monitoring well proximal to the treatment. The downhole process picks first arrivals of P and S waves to infer event locations. Results are sensitive to changes in intervening rock velocities for seismic wave propagation, which can introduce errors in horizontal travel time. A good calibration, a string shot or a large perforation shot, calibrates seismic velocity models, reducing locational uncertainty. If the monitoring well is close to the generated events (within about 500 m), the locational accuracy of events can be as good as (+ or –) 15 m in all directions. For events distal from the monitoring well, locational uncertainty increases rapidly.

Microseismic monitoring can also be achieved using an array of geophones temporarily laid out on the surface or buried in the near-surface and employing a full waveform migration data processing approach derived from 3-D reflection seismic algorithms. Surface based microseismic monitoring employs geophone arrays laid out in sufficient quantity to provide large aperture, high fold and wide azimuth data. Large aperture ensures events are imaged consistently throughout the coverage area; error is invariant across the array. The high fold provided by the channel density enables waveform stacking, amplifying signals that have attenuated through the overburden. As with downhole acquisition, the results are sensitive to velocity model variations; similar calibration shots are conducted to reduce error.

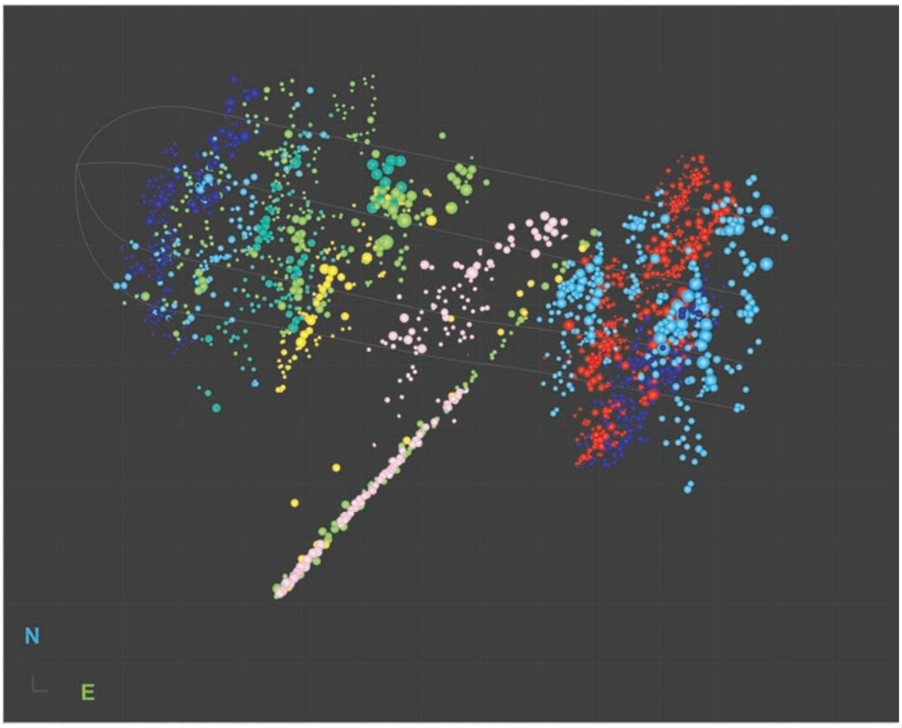

Figure 1: Shaded points represent microseismic events during fracturing, coloured by fracture stage. The long linear trend shown in pink is indicative of a fault re-activation; an undesired outcome.

Applications for Microseismic Data

Hydraulic Fracture Mapping

The primary commercial use for both downhole and surface microseismic monitoring has been for hydraulic fracture mapping. A fracture stimulation treatment is applied to hydrocarbon-bearing rock using pressurized fluid. The improved fracture networks are held open with a proppant (typically sand) applied as part of the treatment. The shear failure of the rock generates detectable microseismic energy. By determining the spatial and temporal location of detected events and plotting them on a map, it is possible to estimate fracture length, event size, trend azimuth and rock stresses at specific times and locations in the reservoir.

These maps can be used for many purposes:

Fracture half-length and trend orientation is used to plan horizontal wellbore orientation and offset well spacing to maximize reservoir drainage area. Trend interpretation is not perfect due to geologic variation, but it does provide a more quantitative analysis than alternatives such as pressure transient testing and tracer logs.

Local stress orientation can also be determined with maps from a surface array or multiple downhole arrays. This data helps identify wellbore orientation with respect to SHmax (maximum horizontal stress) for optimal drainage. The design of the surface array also allows sufficient spatial sampling of wave arrivals to invert for focal mechanisms from the data. Focal mechanisms are used to understand reservoir stress orientation; a critical requirement to optimize wellbore orientation in unconventional recovery.

Fracture geometry determined from a fracture map helps operators understand whether the stimulation remained confined within the production zone or was lost to thief zones by undesirable fault re-activation. A map of the fracture fairway forms the basis of a stimulated rock volume calculation and ultimately, an EUR (estimated ultimate recover). Pumping into a large fault is not only a waste of fluid and proppant; it can result in watering out an offset well or penetration into environmentally sensitive geohazards. Real-time microseismic monitoring can provide a “quick look” assessment early enough to modify treatment plans avoiding deleterious outcomes.

Hydraulic fracture mapping is most commonly used to understand the effect of stimulation treatments and improve completion techniques. Operators are able to quantify the effectiveness of different frac’ing fluids, concentrations, pump rates and durations. Fracture mapping allows comparison of completion techniques. Multi-lateral completion methods such as the “zipper frac,” “inside-out” and “outside-in” methods can be evaluated for efficacy. Taken together, these optimizations can save cost on completions, improve field-wide development and increase hydrocarbon recovery.

Reservoir Monitoring

Microseismic monitoring can sense a wide range of changes in the subsurface that produce detectable microseismic signatures. An application of high interest today is monitoring steam injection in heavy oil operations in Alberta, Canada and California in the United States. Steam is intended to move radially in the reservoir to reduce the viscosity of the heavy oil, generating uniform sweep of recoverable oil. However, nature is invariably heterogeneous and the steam never flows in a uniform path. Microseismic monitoring is being used to identify the actual steam pathways through the reservoir, allowing for informed offset well placement and selection of steam injection rates. Both these elements are critical to efficiently recover the maximum hydrocarbon volumes.

High pressure steam injection can sometimes migrate vertically out of the zone of interest due to the presence of faults and fractures above the reservoir. In rare cases, especially where there is no cap rock (such as in the shallow diatomite reservoirs in Bakersfield, CA), dangerous surface expressions of steam and oil can occur. Real-time alerting when significant upward migration is detected allows the operator to cease injection in the specific well to prevent escalation.

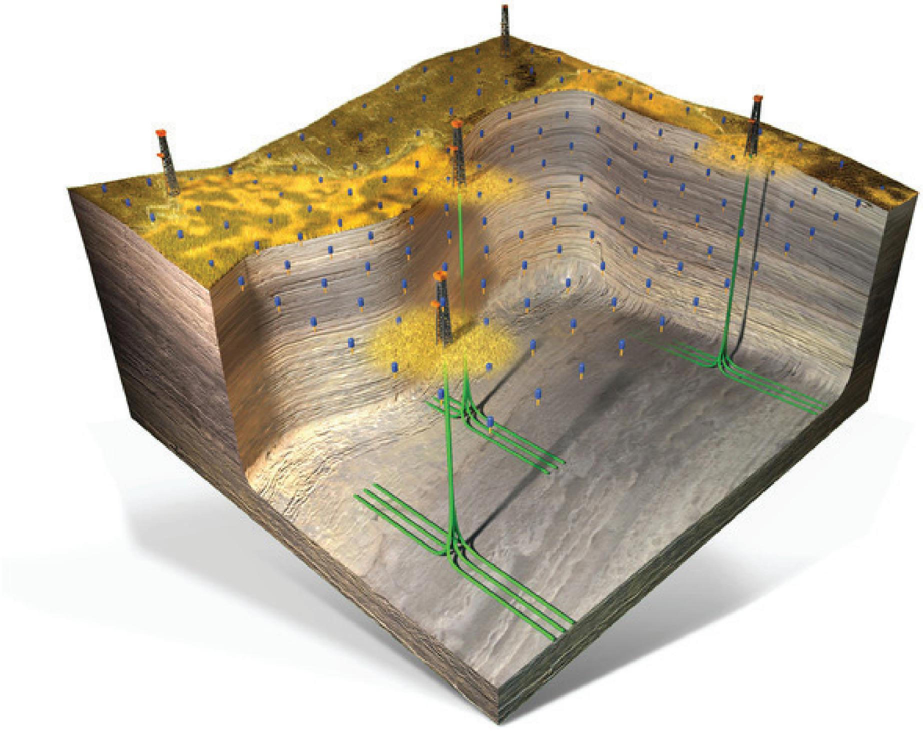

Figure 2 One permanent near-surface array provides wide areal coverage offering real-time monitoring across a field.

A number of high value offshore fields have been equipped with permanent ocean bottom geophone systems to allow for repeat 3-D reflection seismic surveys to detect changes in reservoir fluid saturations. These systems can also passively “listen” for microseismic activity associated with compaction due to oil production and inflation caused by over-injection of water. This monitoring provides detailed information on the distribution of recovered reserves.

The production and injection of fluids from/into the reservoir can cause significant deformation and movement within and above the reservoir. If this movement is large enough, catastrophic wellbore failure can occur through crimping or shearing of the casing. Long term, real time microseismic monitoring can possibly detect the pre-cursors to casing failure, allowing the operator to modify operations and prevent further stress on the production casing.

Induced Seismicity Monitoring

The most recent application of microseismic monitoring is to detect anthropogenic, low magnitude tremors resulting from wastewater disposal or hydraulic fracturing. New studies in British Colombia, Canada; the United Kingdom; Oklahoma and Texas in the United States suggest that, in rare cases, events as high as magnitude ML 4 have been triggered by Oil and Gas activities. The events have been seen, in at least one case, up to months after cessation of pumping activity. In addition, recent research by United States Geological Survey (USGS) seismologist Bill Ellsworth and colleagues has documented magnitude ML 3 events (the minimum detectable by humans on the surface) and larger have significantly increased in the mid-continent of the US since 2000.

In the UK, the “Geomechanical Study of Bowland Shale Seismicity” report analysed causes and suggested mitigation plans (de Pater, C.J and S. Baisch, “Geomechanical Study of Bowland Shale Seismicity,” Cuadrilla Resources, 2011). The report concluded that the repeated seismicity was induced by direct injection of fluid into the same fault zone. Slippage on the fault was induced by high pressure; the strongest events occurring directly after injection. To mitigate the magnitude of the seismic events, the report recommended rapid fluid flowback after the treatments to reduce pressure leak-off into the far field reservoir where unknown faults may exist.

The report recommends monitoring seismicity during the treatments and taking appropriate action when seismic magnitude exceeds the limit set by the “traffic light” system proposed by Zoback in 2012 (Earth, April 2012). The traffic light system (green, yellow, red) has the following workflow:

- Avoid injection into active faults
- Minimize pore pressure changes at depth
- Install local seismic monitoring arrays
- Establish modification protocols in advance
- Be prepared to alter plans or abandon wells

The traffic light system was implemented in the UK using the following warning levels:

- Green - Magnitudes smaller than ML =0: regular operation.
- Yellow - Magnitudes between ML =0 and ML =1.7: continue monitoring after the treatment until the seismicity rate falls below one event per day.

Figure 3: The traffic light systems offers detection signaling for safer injection practises.

- Red - Magnitudes greater than ML =1.7: stop pumping and flow back the well. Continue to monitor.

Some operators have been installing microseismic monitoring systems around their injection well sites; including an adaptation of the "traffic light" early warning system. Regulatory bodies are now evaluating the inclusion of microseismic monitoring as a routine part of well safety evaluations.

Microseismic monitoring is an important technology whose utility is growing.

Microseismic monitoring can lower costs and improve initial production through hydraulic fracture mapping; minimize geohazards; improve secondary and tertiary recovery efforts and demonstrate compliance with environmental safeguards during recovery and disposal operations. Microseismic monitoring can ensure that the Oil and Gas industry will continue to provide for global energy needs safely and cost effectively.