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The Next Generation of Microseismic Imaging is Here

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Integrating advanced hydraulic fracture imaging with fluid system mapping helps unravel unconventional plays

As both crude oil production from conventionally producing fields and the rate of new oilfield discoveries decline worldwide, it is comforting to know that conventional oil is estimated to constitute only 30% of the world's total reserves (Alboudwarej et al. 2006). The biggest piece of the hydrocarbon pie is unconventional resources.

The term "unconventional resources" is used for hydrocarbon reserves whose petrophysical properties, fluid trapping mechanisms, or other characteristics differ from conventional sandstone and carbonate reservoirs and therefore require specialized production strategies. Tight gas sand, coal bed methane and shale reservoirs fall in this category.

In shale reservoirs, the reservoir and source rock are identical. Our familiar concept of an oil/gas kitchen, migration path and hydrocarbon trap does not apply to shale. The risk that an operator will not find hydrocarbons in a shale play is small compared to conventional traps, but the expected production rates are usually lower too.

The focus of geoscientists' and engineers' time and effort has therefore shifted from locating and delineating reservoirs towards increasing the productivity of known resource formations to make them economic.

> Despite truly remarkable achievements so far, our understanding of unconventional reservoirs is immature, especially when compared to our 100+ years of experience in conventional oil and gas exploration and production.

New technologies have proven to be the key to success. Horizontal drilling, multi-stage hydraulic fracturing and microseismic imaging are examples of great technologies that have paved the way for commercial production of shale oil and gas, and there will be more to come.

The continued refinement of this technology suite in the United States is fundamental to our expectations for the Marcellus and Haynesville shale (now considered the third and fifth largest gas fields worldwide), the economic success of the Barnett shale, and to the future development of unconventional reserves worldwide. One scenario of the International Energy Agency (IEA) now sees North American unconventional gas production almost doubling to 670 billion cubic meters (bcm) in 2035 (IEA, 2011). Can we really get there, from about 380 bcm today?

Despite truly remarkable achievements so far, our understanding of unconventional reservoirs is immature, especially when compared to our 100+ years of experience in conventional oil and gas exploration and production. Hydraulic fracturing is still largely a blind process and too many wells fail to meet the operator's expectations. Continuous technological advances will be needed to sustain commercial shale gas production and ultimately to meet the IEA's prediction for 2035.

As a leading geoscience solution provider, Spectraseis sees its role as pushing the frontiers of current subsurface information technologies, to shine an ever-brighter light on the intricacies of unconventional plays and improve their economics with richer, faster reservoir understandings.

In this article, we introduce some recent technology breakthroughs and explain why the successful future of microseismic monitoring lies in broadband data acquired with new types of arrays.

We show that such data – in combination with innovative processing algorithms – not only improves on current fracture stimulation monitoring approaches but also has the potential to integrate fluid system information for a more complete reservoir stimulation evaluation.

Using the complete wavefield

The results of any geoscience data analysis are only as good as the quality and integrity of the recorded data set. Energy radiated from microseismic events is small by definition (micro meaning, literally, "very small") and recorded signals are often weak and masked by noise.

The critical signal-to-noise ratio (SNR) in microseismic data is a function of event size, distance from the event, local noise conditions, quality of the recording equipment, and the position of the recording station with respect to the event's radiation pattern.

Capturing the most complete wavefield in time, space and frequency is a good strategy to minimize the risk of missing these faint – but precious – signals.

We see four requirements for an optimized microseismic acquisition system, incorporating several new technologies only recently available on the market.

(i) Don't ignore shear waves

Single component data recordings, as delivered by conventional 2D/3D seismic recording systems, have ignored a large portion of the information radiated by microseismic events and are likely responsible for past failures of surveys acquired at the surface. S-waves are often the strongest signals recorded in microseismic data. The S-waves triggered by microseismic events are normally observed on the horizontal components of a 3-C receiver and are weak or completely absent on the vertical component.

A standard requirement for many years in borehole microseismic and VSP applications, three-component (3-C) recording is essential in both borehole and surface microseismic surveys because only 3-C

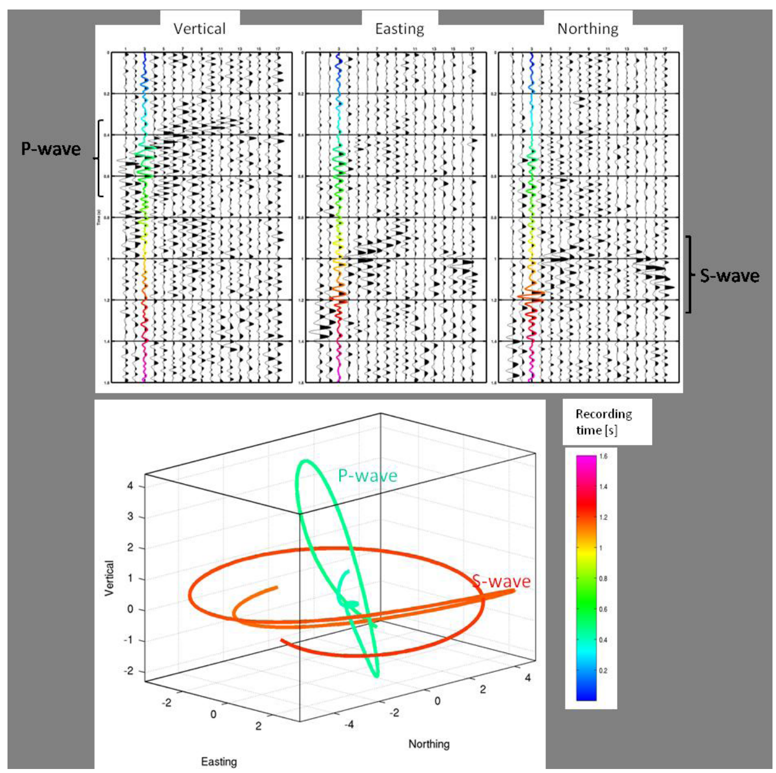

Figure 1: 3-C trace gather of a microseismic event triggered in U.S. shale (top) and particle motion (hodogram) for a single station (bottom). P- and S-waves can clearly be distinguished in the hodogram based upon their polarization properties. Note that the S-wave arrival is absent on the vertical component and would not be captured by single-component geophones.

data embodies the full three-dimensional wavefield. Assuming a Vp/Vs ratio of 2, the maximum amplitude of an S-wave phase (SH or SV) radiated by a shear event is 8 times larger than the maximum amplitude of the associated P-wave (Aki and Richards 2002), but a single component system probably won't record it. We simply cannot afford to keep ignoring this data.

Figure 1 shows how 3-C instruments not only capture all wave modes, but also facilitate polarization analysis to distinguish easily between the different modes. Classification of the recorded signals into vertically polarized P-waves and horizontally polarized S-waves is crucial to avoid imaging false positives from misinterpreted wave modes.

ii) Use high-sensitivity instruments

Like a raindrop in the forest, a microseismic signal is small and weak. Many of them occur far from the recording array, at the remote end of a multi-stage frac and well below the surface in a deep formation. High-sensitivity instruments are essential to capture weak microseismic signals and an instrument with low self-noise is needed to ensure that any event stronger than background noise is detected.

iii) Capture the low frequencies

An ordinary 15 Hz geophone doesn't measure the optimal frequency band for evaluating unconventional reservoirs in all acquisition geometries. True broadband instruments with a good frequency response down to 0.1Hz (and up to 1000 Hz) are a vastly superior choice, particularly for surface acquisition.

> Optimizing array geometries is one of the most powerful ways to improve data quality and increase the value of microseismic data to the interpreter.

Recording the low frequency segment of the wavefield is especially important for large measurement offsets, where high frequency signals tend to be heavily attenuated. The maximum S-wave amplitudes of microseismic signals recorded at the surface often occur at frequencies well below 20 Hz.

However, the major benefit of recording at low frequencies is the shallow and deep subsurface information added by characterizing the continuous ambient wavefield. More about that in a moment.

Figure 2: An UltraSense™ microseismic recording node monitors a fracture treatment in Canada.

iv) Get rid of cables: use nodes to optimize your survey design

Optimizing array geometries has been poorly neglected in many microseismic designs, although it is one of the most powerful ways to improve data quality and increase the value of microseismic data to the interpreter. Whether they're deployed at the surface or multiple downhole configurations, nodal systems have the advantage over cabled arrays for data acquisition.

Obviously, nodal systems offer vastly more flexibility in acquisition geometry design – a critical consideration when every stimulation program comes with its own unique challenges. Forward modeling with tell you where you should position receivers to get the answers you need, and you don't want to be tied up with cable constraints.

Other advantages of nodal acquisition include a low-impact environmental footprint, easier permitting and operational safety benefits. These should not be overlooked, given the high public and regulatory profile of unconventional resource development.

Figure 2 shows a Spectraseis UltraSense™ nodal surface recording station deployed on a recent frac monitoring job at a shale play in Canada. This three-component instrument has a sensitivity of 4800 volts per meter per second (V/m/s) and self-noise level below the

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seismic background noise of the Earth. The sensitivity of a standard geophone is generally less than 100 v/m/s. Time synchronization and positioning are achieved by GPS. Arrays of several hundred stations are quickly deployed for a typical fracture stimulation survey.

The associated UltraSense™ multi-level borehole tool, which has the same sensor specifications as the surface nodes, can be integrated with the surface gear and other borehole acquisition modes to optimize the acquisition geometry for any stimulation program.

UltraSense™ array deployments continuously record the ambient seismic wavefield before, during and after a fracture stimulation. Pre- and post-frac recordings provides a rich new data set for monitoring fluid system changes caused by the frac operations.

This system fully meets the requirements I described above, and no doubt will become standard for microseismic surveys in the coming years, as operators demand more value from their investment in microseismic data.

The most complete physics

Until now, the standard approach to microseismic event location has been automated arrival time picking followed by a ray tracing based travel time inversion. Many microseismic data processing workflows still apply this method. It is overdue for an update.

Elastic wave-equation migration of multi-component data is the more natural and most physically complete approach.

Computationally expensive in 3D scale, such methods were not practical until recent years. Thanks to the evolution of fast computing clusters and algorithm improvements, the time has come to start using the very significant advantages of elastic wave-equation imaging for microseismic monitoring.

> Event characterization is a powerful benefit of elastic wave equation imaging. It facilitates a simple and direct measure to understand the local stress field in the target zone.

How does this work? Spectraseis' time-reverse imaging (TRI) algorithm propagates time-reversed microseismic signals from the receiver locations through a velocity model back to its source location. TRI solves the 3D elastic wave-equation in the velocity-stress formulation on a rectangular, staggered grid using a finite difference technique. TRI reduces analyst interactions to a minimum and does not require arrival time picking – eliminating a common source of error in microseismic data processing.

If our velocity model is good, the resulting TRI image will focus at the location where the event has occurred. However, the result not only pinpoints the event location, but actually images a proxy of the event's three-dimensional (3-D) radiation pattern.

As shown in Figure 3, the imaged 3-D pattern can be matched with theoretical radiation patterns of common event types. Only minor interpretation is needed to determine the underlying event mechanism and orientation, represented by the familiar beachball.

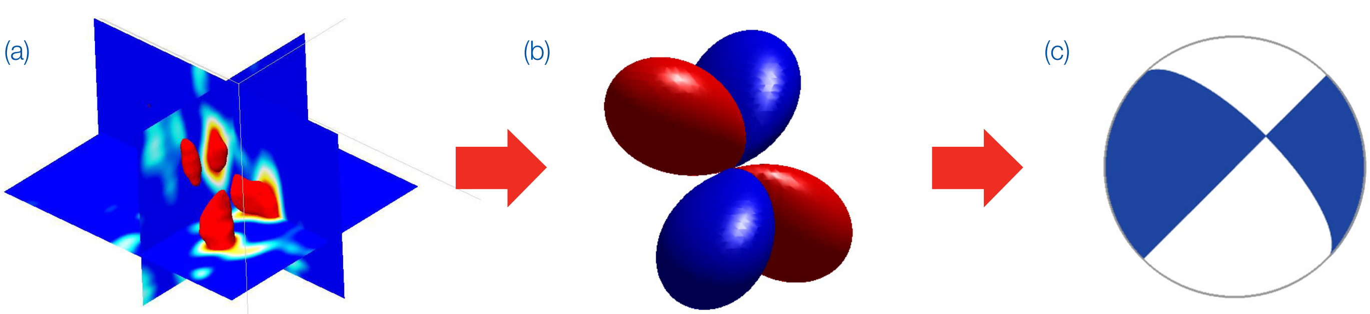

Figure 3: From TRI event image to focal mechanism: the 3-D pattern in the TRI image domain is compared with theoretical radiation patterns to determine the event's source mechanism and orientation. (a) 3D TRI image of the microseismic event shown in Figure 1 (b) P-wave radiation pattern of double-couple source (c) Focal mechanism of the shear event

This event characterization capability is a powerful benefit of elastic wave equation imaging. It facilitates a simple and direct measure to understand the local stress field in the target zone.

To tackle the inherently large computational requirements, TRI algorithms are designed to run on ultra-fast GPU clusters, making elastic-wave equation imaging now deliverable to customers in commercial timeframes.

Understanding fluid system changes

Microseismic signals make up only a tiny fraction of a continuous passive seismic survey recording. The vast majority of the recording captures the stationary seismic background noise of the Earth's crust.

Earthquake seismology and engineering geophysics disciplines extract valuable information on vertical velocity structure or horizontal inhomogeneity in the subsurface from these data.

In recent surveys, Spectraseis has been analyzing this ambient wavefield to identify fluid system changes occurring in the target zone as a result of fracturing operations, which create dramatic new physical contrasts and reservoir dynamics. Fluid effects on seismic amplitudes have been around for a long time in active 2D/3D seismic and have been exploited successfully as direct hydrocarbon indicators (Chopra and Marfurt 2005). Spectraseis calls upon the same physical principles in analyzing continuous passive data recordings in the frequency domain.

This ambient wavefield characterization (AWC) method, now the subject of 14 issued and pending patents, employs spectral attributes that are sensitive to the subsurface rock-fluid system (Saenger et al. 2009). After removing non-stationary signal elements, a comparison between attributes from pre- and post-frac recordings has then the potential to highlight fluid system changes related to the fracture stimulation treatment.

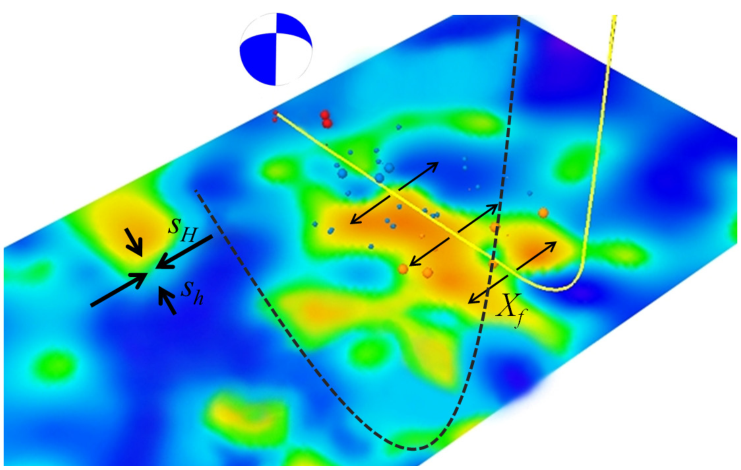

Figure 4: Improved reservoir development through integration of hydraulic fracture imaging with AWC fluid system mapping. A future well (dashed) is planned based on local stress field information and ESRV estimates derived from 3-C broadband microseismic analysis.

Figure 4 includes an example based on a recent survey over a shale play in North America. The map displays the ratio between post- and pre-frac attribute values. The division eliminates stationary attribute patterns caused, for instance, by near-surface geology. High values (in red) indicate changes in the stationary characteristics of the ambient wavefield recorded after the treatment. The map is projected to the target depth for interpretation purposes.

High values are observed in the zone near the treatment well. These patterns can be interpreted with respect to fluid-system changes caused by the fracture stimulation and add an exciting slice of new information for estimation of the effective stimulated reservoir volume (ESRV).

Integrating all the data

A microseismic survey maps the extent, direction and asymmetry of stimulated fractures by interpreting the spatial distribution of induced microseismic events. But event locations only provide an estimation of the induced fracture network. Information on effective permeability or even fluid mobility inside the ESRV is limited.

Pre- and post-frac AWC can close this information gap by adding fluid system information to the imaged fracture network. It provides an additional, independent input for reservoir simulation models and contributes to the estimation of important parameters, such as the ESRV, the fracture half-length Xf and the ultimate productivity of the well.

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Moreover, with elastic wave-equation imaging, the character and location of microseismic events can be used to directly map the local stress field in the target formation, helping the operator to determine the optimal orientation for future treatment wells.

Figure 4 illustrates a combined analysis of event locations, focal mechanisms and AWC attributes. The sketch shows how a future well can be planned with more confidence regarding its optimal orientation and distance to the adjacent well. Integrated analysis of the many aspects of broadband microseismic data facilitates improved reservoir management, eventually resulting in more economic wells and higher production.

670 bcm, here we come!

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