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Integration enhances shale production

Seismic attributes that correlate to drilling and completions data aid in reservoir understanding.

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Although 3-D seismic data has played an important role in the development of unconventional resources such as shale plays over the past several years, until quite recently these seismic datasets have been used almost exclusively to provide structural information about the target formations, primarily to avoid or anticipate faults as well as to help ensure that the horizontal portion of the production wells stay within the target zone.

This bias towards using 3-D seismic data only for structural guidance was no doubt predicated on the assumptions brought to bear during the early development of these unconventional resource plays. During this initial exploratory phase, E&P operators assumed that unconventional resource targets such as shale formations were relatively homogeneous formations with little variability in terms of reservoir quality. However, as horizontal completions technology matured, it rapidly became clear that this assumption of homogeneity was incorrect. Well performance within these formations can vary by a factor of two or more, even when using identical horizontal completion strategies. Seismically derived attributes can play an important part in understanding this well performance variability and also can provide insight into the behavior of other geophysical measurements used to evaluate completion effectiveness, such as microseismic monitoring studies.

Seismic attributes

Three-D surface seismic data obviously is capable of providing a wealth of information beyond traditional structural delineation, particularly given an appropriate survey design, data acquisition, and processing and analysis strategy. In particular, rich-azimuth, full-offset 3-D seismic datasets can provide meaningful insights into the geomechanical and rock properties of target formations as well as indications of the magnitude and orientation of local stress field variations and/or pore pressure variations. When coupled with more traditional seismic attributes such as acoustic impedance and spectral decomposition, properly designed and processed 3-D seismic datasets provide a rich portfolio of pre- and post-stack attributes that can be used to understand and delineate reservoir heterogeneities that influence well performance.

These seismically derived attributes have traditionally been used in hydrocarbon exploration to map "sweet spots" that are likely to be preferred well locations. However, these same attributes can be correlated

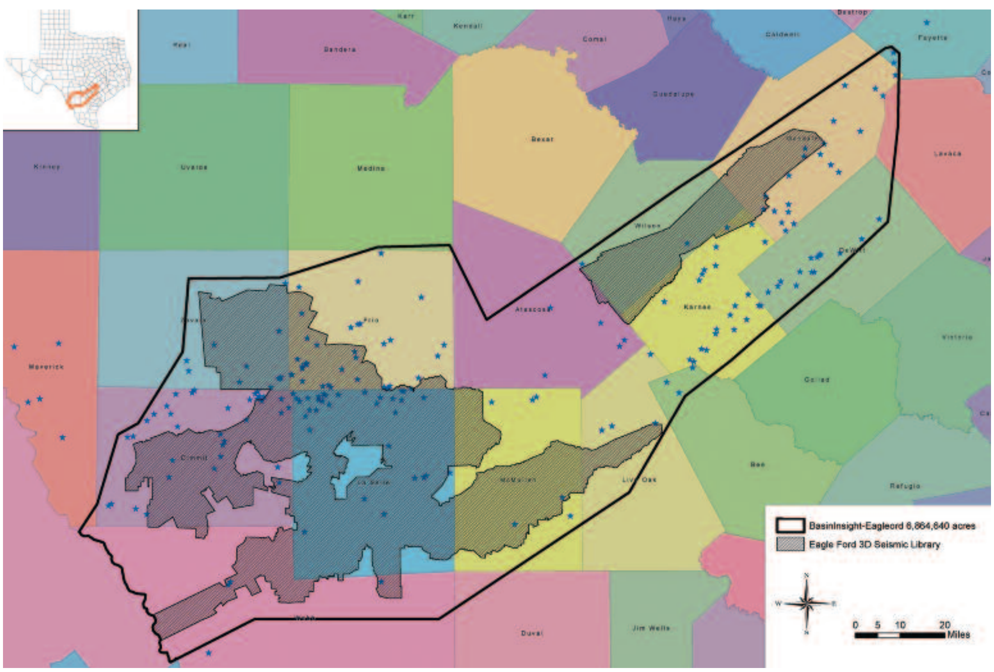

FIGURE 1. The Eagle Ford Basin-InSight survey covers almost 7 million acres. (Images courtesy of Global Geophysical)

against engineering data to determine those factors that influence well performance and that can therefore be used to optimize well drilling and completion strategies.

The Eagle Ford shale in South Texas is an excellent example of an unconventional resource play that exhibits significant variability in terms of well performance. To better understand this variable performance, Global Geophysical has undertaken a massive, basin-scale reservoir characterization project designed to provide an integrated 3-D earth model with prospect-level detail spanning a study area of almost 7 million acres. This offering, known as Basin InSight Eagle Ford, integrates well log, core, petrophysical, and 3-D surface seismic data to develop a comprehensive understanding of reservoir quality variations across the basin.

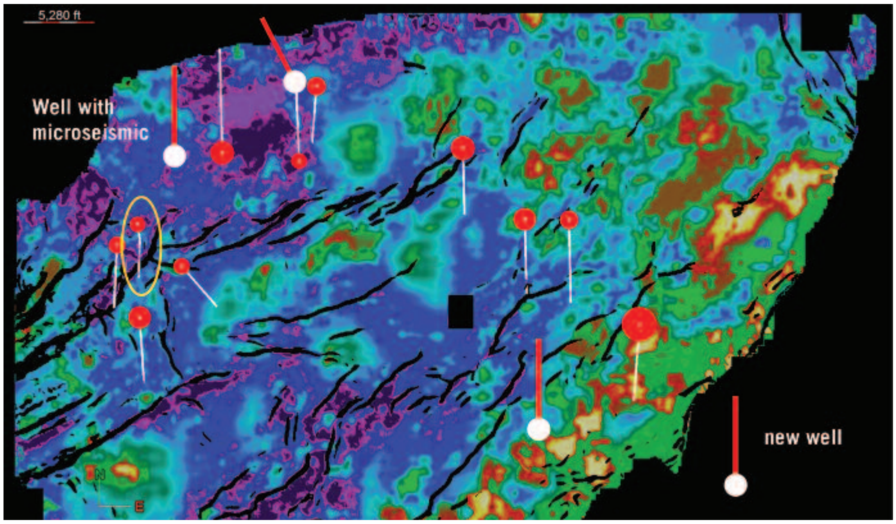

FIGURE 2. A multivariate statistical analysis that was applied to compute a non-linear combination of attributes was able to predict well performance with a correlation coefficient of 0.95.

Global's 3-D multiclient seismic datasets in the Eagle Ford are the foundational element of this basin-scale geomodel. These datasets have a number of design features that are essential for meaningful seismic attribute work aimed at characterizing the target formations:

- ***High-fold, high-density spatial sampling.*** These characteristics are primarily related to signal-to-noise enhancement and prestack imaging quality;
- ***Full-offset data with rich-azimuth distributions.*** These characteristics are important not only for enhanced structural imaging but also to understand azimuthal anisotropy, which can be used to infer stress field magnitude and orientation. The longer offset data in particular is necessary to measure changes in azimuthal anisotropy as well as to better constrain elastic inversions that characterize the geomechanical properties (stiffness, brittleness/ductility) of the target formations; and
- ***Processing algorithms that correct for anisotropy.*** For any meaningful attribute work to be done, it is essential that the processing algorithms used accurately correct for both layer anisotropy (Vertical Transverse Isotropy or VTI) and azimuthal anisotropy (Transverse Isotropy or HTI) during the velocity estimation and prestack imaging steps. Global employs a patented migration scanning technique to determine these corrections, solving for azimuthal anisotropy without the compromises involved in azimuth sectoring or offset vector tile approaches. Without accurate VTI and HTI corrections, data are projected to the wrong spatial locations, resulting in significant amplitude errors in the prestack images, particularly at the longer offsets. Since these long-offset prestack amplitudes drive the attribute calculations for elastic inversions, attributes calculated without the correct application of these corrections can be very misleading.

These resulting 3-D seismic datasets are augmented by well log, core, and other petrophysical data to calibrate the many relative properties estimated from the surface seismic data as well as to ensure proper depth conversion of the seismically derived structural framework. While this integrated, basin-scale geomodel provides the ideal framework for representing the spatial variability of reservoir properties such as thickness, lithology, porosity, brittleness, acoustic and elastic impedance, and local stress field magnitude and orientation, unless the relationship of these properties to drilling and completions engineering data is understood, the information cannot be used to predict and influence well performance.

Well performance prediction

To address this challenge, Global has developed a selective portfolio methodology that uses a non-linear statistical approach to predict well performance based on the correlation of key geoscience and engineering attributes against the measured well performance. There are obviously a number of possible measures that can be used to assess well performance (IP, EUR, etc.), but for the study area, maximum monthly gas production was selected as the best measure of comparative well performance. To determine the factors that influ-

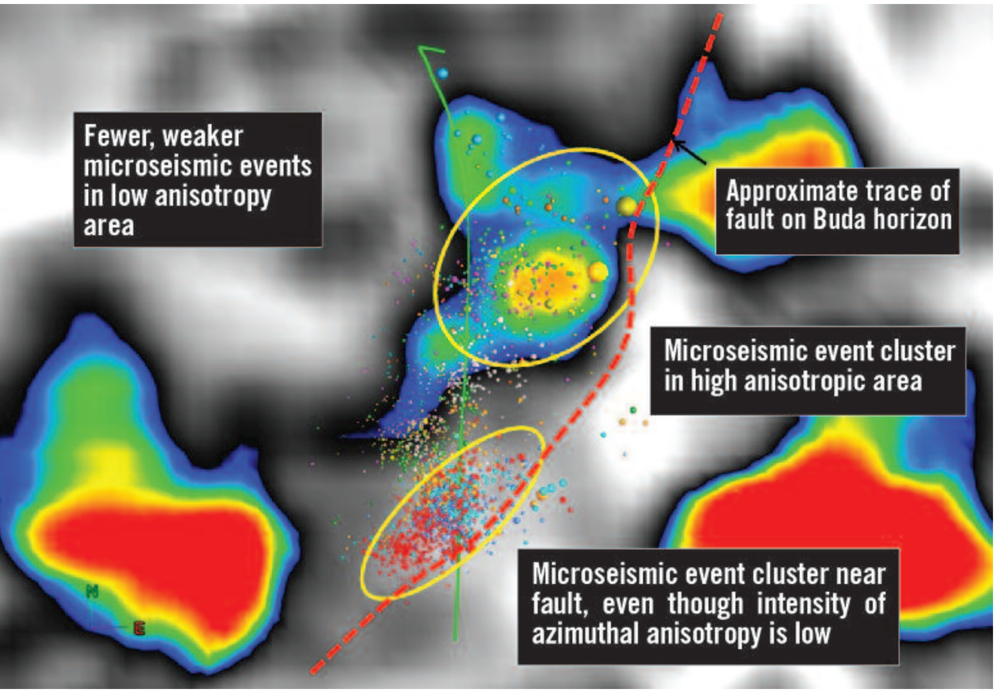

FIGURE 3. A number of spatial correlations are observed when examining the azimuthal anisotropy near the well in the upper yellow circle that help to explain the observed microseismic response during hydraulic stimulation of this well.

ence this production metric, a suite of nearly 40 attributes – both seismically derived geoscience and engineering-based completions data – were correlated against the selected production metric to identify a small portfolio of key attributes related to production performance. For this particular example, five attributes were ultimately selected as members of this portfolio:

- Lateral length – obviously related to volume of reservoir rock intersected by the well;
- Frac factor – a seismically derived elastic attribute describing the brittle/ductile quality of the rock;
- Azimuthal seismic anisotropy – a proxy for differential stress and/or open fractures;
- 10 hz spectral decomposition – found to be a gas indicator; and
- 32 hz spectral decomposition – a proxy for formation thickness in the Eagle Ford shale.

It should be noted that the basis for selecting these attributes was not simply the statistical correlation with the selected production metric – care must be taken to consider all of the available data (petrophysical, geophysical, and engineering) within the context of the geologic setting to select the most appropriate attributes to populate the portfolio. Although none of the selected attributes individually had a correlation coefficient greater than0.7, a workflow using multivariate statistical analysis was applied to compute a non-linear combination of these attributes that was able to predict well performance with a correlation coefficient of 0.95. Importantly, this correlation was verified by the analysis of subsequent wells within the study area that were not included in the original predictive analysis (Figure 2).

As impressive as this predictive success is, an investigation of the relationship of the contributing attributes to well performance provides even more insight into the factors that affect completions and production performance.

For example, in examining the seismically derived azimuthal anisotropy in the vicinity of the well circled in yellow (Figure 3), a number of spatial correlations are observed that help to explain the observed microseismic response during hydraulic stimulation of this well.

Interpreted in isolation, the microseismic response had indicated a favorable well completion with significant microseismic emissions along the entire length of the well bore, suggesting that the performance of this well should be good. When viewed within the context of the azimuthal anisotropy response (one of the key seismic attributes based on the prediction analysis), a much different picture emerges. To begin with, a large number of the microseismic hypocenters are clustered along the edge of a major fault that intersects the toe of the well, and there is little indication of activity beyond that fault, suggesting that it is a permeability barrier. In addition, the asymmetrical microseismic response in the mid-section of the well correlates with the zone of high azimuthal anisotropy, suggesting that the fractures induced by hydraulic stimulation are connecting with a preexisting natural fracture network.

Although this type of integrated geoscience and engineering analysis is still in the early stages of development, it is already yielding important insight. Current research and development activities in this field, particularly with respect to a new microseismic technology known as tomographic fracture imaging, promise to yield even deeper insights into the characteristics of these complex reservoirs. E&P