Better Seismic Delineating Shale Plays

By Mark Egan

HOUSTON—In the early days of tight oil and shale gas development, operators typically drilled a regular pattern of horizontal wells and fractured them at a regular spacing throughout the lateral. On average, the value of the resulting hydrocarbons justified the investment, leading to a boom in exploration and production activity in North American shales.

However, operators have observed considerable variation in the productivity of individual wells and producing zones, and have sought ways to better understand and predict the reasons why. It has become clear that reservoir heterogeneity, in situ stress, and natural fracture density and geometry play key roles.

Thanks to advances in acquisition and processing technologies, surface seismic techniques can help characterize these important controlling factors and improve production rates. Several studies have shown that, irrespective of regional stress regimes, local stresses vary considerably in magnitude and direction. Surface-seismic imaging techniques can map reservoir heterogeneity and measure anisotropy—directional inequalities in acoustic velocity related to localized in situ stress conditions.

Stress, Fracture Orientation

All shales exhibit vertical anisotropy and many also exhibit azimuthal variations related to stress and natural fractures. Horizontal permeability is necessary for gas and oil to flow from the reservoir formation into a fracture and thence to the well bore.

It is important to know the directions of minimum and maximum stress when designing the orientation of horizontal wells, as well as the orientation and location of perforations and subsequent induced fracturing during completion. When stimulation fluid is pumped at high pressure through well bore perforations, the reservoir formation will crack in the direction it finds the least resistance. This means vertical fractures will open in a plane oriented orthogonally to the minimum stress direction.

Fractures induced in other directions are likely to exhibit increased tortuosity, which inhibits proppant transport. Consequently, for optimum performance, horizontal wells should be oriented orthogonally to the plane of the fractures, and should therefore be drilled in the direction of minimum stress (Figure 1). Drilling performance, including rate of penetration and well bore stability, is impacted significantly by the choice of well trajectory relative to principal in-situ stresses.

In most shales, the maximum stress direction is vertical, making horizontal wells the most effective means of production. There are some exceptions, such as the western part of the Sichuan Basin in China, where the Indian continental plate is pressing into the basin, making the horizontal tectonic stresses greater than the overburden stress. Because of this, the most likely fracture plane is horizontal, and hydrocarbon production relies on vertical permeability, which can be

![FIGURE 1](image)

Horizontal wells should be drilled in the direction of minimum stress (blue arrows) because fractures are most likely to propagate orthogonally to that direction.
orders of magnitude less than the already low horizontal permeability. In rare cases like this, assuming appropriate formation thicknesses, vertical wells might be the best option.

**New Seismic Technology**

In all types of exploration, surface seismic surveying is used to provide images of the subsurface in order to identify likely structural and stratigraphic traps. For drilling and completion campaigns in tight formations, seismic data are useful as well for identifying the minimum and maximum horizontal stress directions and natural fracture density. This is achieved by measuring azimuthal anisotropy in the velocity of sound waves through the reservoir formation. Faster velocities can correspond to the maximum stress direction and/or the orientation of natural fractures.

In shale plays, the desired contributions from seismic data are accurate depth images, high-resolution seismic velocities, and calibrated prestack inversion products. The inversion products are especially important in workflows that integrate the seismic data with well logs, core data, and other measurements.

The purpose of that integration is to better identify lateral and vertical variations within the reservoir compartments, and to characterize reservoir quality (RQ) and completion quality (CQ) to optimize well positioning and hydraulic fracturing strategies.

Factors contributing to good RQ include high gas saturation and kerogen content, high matrix permeability and porosity, and high pore pressure. Factors contributing to good CQ include strong fracture containment, fracturable formations, and mineralogy—in particular, detecting clays with high rock-fluid sensitivity. While seismic data alone cannot confirm all these factors, when combined with other measurements, they can provide an indication of the most prospective well locations.

Continuous advances in acquisition and processing technology have led to seismic data of ever-improving quality and reliability, which can be trusted to provide an increasing range of valuable information about lithology and other important reservoir conditions. The advent of ultrahigh-count, continuous recording systems and new coherent noise removal techniques allows great flexibility in designing full-azimuth survey geometries that deliver optimal noise attenuation and dense sampling of the seismic signal.

For example, a state-of-the-art integrated-point-receiver land seismic system is capable of supporting more than 200,000 live channels. High-channel capability enables the operator to record long-offset, full-azimuth point-receiver data at high trace densities. In addition to high-fidelity measurement of the upcoming seismic wave field, dense sampling of various types of coherent noise enables it to be effectively removed or analyzed to provide additional subsurface information.

Resolution is further improved by using broadband vibroseis source techniques and recording with high-fidelity geophone accelerometers. Broad bandwidth, especially low frequencies, is essential for accurate inversion to derive rock properties. Improvements in processing include surface wave inversion. This enables improved correction for near-surface effects that can degrade the seismic image, which is particularly important when performing prestack depth migration (PSDM).

Full-azimuth acquisition, combined with anisotropy-comprehending amplitude-versus-offset inversion, can indicate local stress directions, and help optimize well orientations and fracturing efficiency.

**Onshore Texas Study**

High-quality point-receiver data were acquired over a field in Texas. Although not a shale play, this is a good example of using surface seismic data to characterize stress fields. The data were acquired using a broadband vibroseis source and a large channel count of point-receiver geophone accelerometers, which deliver reduced signal distortion and increased bandwidth, compared with conventional sensor technology.

Processing included PSDM after build-
ing a velocity model that incorporated azimuthal anisotropy. Figure 2 shows an example section through the new data compared with data at the same location from a conventional 3-D survey. The yellow well bore trajectories land horizontally in the zone of interest. High-quality, depth-imaged data are required in areas such as this because landing a well out of zone can be a million dollar mistake.

The point-receiver data clearly image a major fault that is difficult to interpret in the conventional data, providing information that is particularly important when drilling and fracturing horizontal wells. The new data also show improved imaging of overburden layers, which often can identify other possible plays and potential drilling hazard zones.

Figure 3 shows a horizontal slice at the target depth through the 3-D model, color-coded with azimuthal anisotropy determined from seismic velocities. Blue indicates zones of isotropy; i.e., where velocity is the same in all azimuths. Warmer colors (yellow, orange and red) denote areas where there is a difference. The white rectangle is an area used for particular investigation of the impact of azimuthal anisotropy.

Figure 4 is an enlarged display of this area, showing the locations of three horizontal wells. All are oriented in the same direction, presumably based on the drilling engineers’ knowledge of regional stresses. Also shown are vectors determined from the azimuthal analysis of velocities aligned in the fast direction: the direction of maximum stress.

The analysis indicates that the two wells on the left were oriented optimally in the direction of minimum stress. However, the seismic velocity information suggests the well on the right, although relatively close to the other wells, was drilled oblique to the minimum stress direction. After reviewing these findings, the operator concluded there was “excellent agreement between the seismic data and the completions,” and company engineers subsequently re-examined their drilling and completion strategies in the area.

The vectors displayed in this example indicate that there are many local variations in the anisotropy—indeed, the anisotropy exhibits heterogeneity itself. The shadow zone to the left of the left-hand well in Figure 4 is possibly a fault. On one side of this fault, the maximum stress is parallel to the fault plane, while it is orthogonal to it on the other side. This is consistent with experience from geomechanics stud-
ies, which suggest that rotation of stress fields across faults is fairly common.

**Additional Case Studies**

In an example from the Fayetteville Shale, a reservoir model was developed that integrated petrophysical, sonic, image, core, stimulation, production, microseismic and processed surface seismic data. This dynamic reservoir model was used to history match the short- and long-term production performance and its variations across the exploration area.

The reservoir characterization and dual-porosity simulation model was found to be consistent with variations in the gas production history of different perforation clusters, providing confidence in workflows for selecting future drilling locations, identifying the best landing points, optimizing well spacing, and guiding completion practices.

Reservoir heterogeneity is a key factor controlling productivity in shale plays. Resolving details of heterogeneity from seismic surveys requires reliable broadband data for accurate matching to well logs through inversion to acoustic impedance. Accurate inversion is particularly dependent on low-frequency data.

In another case, an integrated point-receiver land seismic system was used to acquire data over a field operated by Saudi Aramco. Figure 5 shows a low-frequency (4-12 hertz) model derived from well log data and the inverted results of the new point-receiver survey. The new data show a good match at the well location and considerable detail throughout the section. By contrast, legacy seismic data from the same location show a worse match to the well and less detail in the section.

**Conclusion**

For optimum value in developing shale plays, seismic surveys should have broadband data representing a full range of azimuths. The data should have fine spatial sampling and be capable of compensating for near-surface anomalies and other sources of noise that can mask subtle variations in the seismic response at reservoir level.

From survey design to data processing, careful attention must be given to ensuring the seismic volume is prepared optimally for inversion and well matching. When these objectives are achieved, seismic data can help prioritize drilling locations from better to poorer productive potential, and can characterize the stress information needed for efficient and productive drilling and completions programs.

Further advances in acquisition and processing technology, coupled with integrated workflows that combine multiple types of measurements, will make high-quality seismic data an increasingly valuable tool for maximizing production in shale plays.

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