HOUSTON—Conventional plays are quantified and defined by the presence of an economically filled hydrocarbon reservoir that was created when hydrocarbons flowed from a source rock into a waiting trap that was then sealed. The variables or conditions that must be present for this to occur are source, maturation/expulsion, migration pathways, reservoir, trap, seal and timing. Unconventional reservoirs may actually be the source, which means they do not require traps or seals. The source bed is so tight that the fluid remains in situ.

Therefore, maturation and expulsion, the presence of migration pathways, proper seal and timing are not requirements. If most conventional parameters for delineation of the play are not required, what is?

Addressing that question requires looking at some unconventional plays. The greatest expansion of activity in the unconventional play arena the past couple years no doubt has occurred within the United States in the Bakken and Eagle Ford plays, but also in areas such as the Barnett Shale. Oil reserves for these three plays could total 30 billion barrels. This is where technological advances have been focused for delineation, drilling, completion and production. It is also where not only U.S. energy companies, but also international and multinational energy companies, have been expanding their portfolios.
This article focuses on unconventional play delineation and production trends in the Barnett and Eagle Ford plays, and new technology and innovative workflows that can be used to reduce risk and optimize production.

The Barnett Shale formation was laid down in the Fort Worth Basin 350 million years ago. The reservoir within this formation is not considered true shale because of its highly variable mineral composition, which is dominated by large percentages of silica. The mineralogy lends itself to increased brittleness, which has resulted in a naturally fractured reservoir. Gas reserves from 5 trillion to 30 trillion cubic feet have been estimated in the Barnett, along with almost 100 million barrels of oil and a potential 1.1 billion barrels of condensate.

The Eagle Ford Shale deposition occurred 90 million years ago on top of the Woodbine group within South and East Texas. It is the source rock for the overlying conventional Austin Chalk oil and gas reservoir.

The reservoir unit within this formation is actually more of a carbonate than shale, with only around 30 percent clay present. The higher percentages of carbonate increase its brittleness property, which suggests it is more favorable for hydraulic fracturing. Oil reserves alone have been estimated in the range of 5 billion to 20 billion barrels.

Both the Barnett and Eagle Ford reservoirs have a propensity for brittleness, which can make them susceptible to fracturing. Therefore, it should be no surprise that the industry has focused on predicting areas of potentially increased permeability resulting from the presence of natural fracturing, which may be further enhanced with hydraulic fracturing.

**Room For Improvement**

The current methodology is to identify these “sweet spots” and optimize production with intense horizontal drilling and hydraulic fracturing. The common practice is to use wells and sometimes conventional seismic to predict rock properties (including physical as well as geomechanical properties) to determine the trend of maximum stress, and then target the wells perpendicularly to that trend direction in order to facilitate hydraulic fracturing.

Of course, microseismic data are acquired also for more direct measurements of the maximum/minimum stress, velocity and anisotropy rock properties to increase the accuracy of modeling and subsequent predictions.

Yet, some independent companies at the forefront of the play have used mostly well data. They correlate their wells, tie zones of increased brittleness, and drill between the existing wells. The net result for these workflows in the Barnett Shale, for example, is reflected in the fact that 80 percent of the production has been reported to come from 30 percent of the completions. This suggests there is room for improvement.

Why do 70 percent of the completions fail to significantly contribute to production? There can be several explanations. First, the well bore may not be optimally positioned at a direct right angle to regional stresses. Several factors can lead to the failure: inaccurate rock property calculations and mapping; inaccurate inversions, attribute extraction and mapping; or complex structural fabric overprinted by several regional events.

**Enhanced Technology**

Fortunately, enhanced performance technology and tools have been designed to facilitate accurate reservoir characterization in resource plays. The tools and
workflows are designed to provide solutions for unconventional play types with an integrated and multidomain unified approach across the entire workflow, from full-azimuth processing and imaging up to reservoir engineering to reduce uncertainties in the decision making, planning, drilling and completion process.

Generating fracture intensity properties for every reservoir unit on the static model grid, associated with identifying fracture orientation and aperture, can be used to build a discrete fracture network model with associated specific heterogeneous reservoir rock properties.

At the start, examining and interpreting legacy well data are crucial to mapping and modeling rock properties for an unconventional play. For more accurate models, a multimineral optimized modeling approach that relies on established methods for predicting kerogen is used (Figure 1). The method employs triple-combo logs, so no specialty logs need to be run. Once the initial model has been built for an area or play, subsequent log suites are quickly processed.

Despite the challenge of resolution for unconventional plays, conventional seismic data offer valuable information between wells with regard to lithology, fluid contents and in situ stress events. Workflows and technology are needed to transform the seismic data into properties that can be correlated at the bore hole location.

To accurately extract rock properties from seismic without azimuthal biasing, full-azimuth (or 360-degree) processing is required. New, full-azimuth angle domain imaging and analysis technology was designed to deliver unsectored data for subsurface velocities and structural attributes, medium (rock and fluid) properties, and reservoir characteristics. Because this process provides in situ recovery of continuous azimuth and continuous angle prestack data in depth, additional information from both modern and legacy seismic data (especially wide- and rich-azimuth data with long offsets) is produced.

The technology is designed to address near-surface or complicated structural imaging challenges such as over the Bakken Shale, and low velocity-anomalies such as gas pockets among other conventional play challenges, including imaging below salt. Effective for imaging and analysis in unconventional, low-permeability and fracture system plays, full-azimuth angle domain imaging and analysis provides stress and fracture detection for accurate reservoir characterization with its solutions for anisotropic tomography.

The outputs contain seismic signatures that are observable, measurable and correlative to shale properties. In a case study of the Eagle Ford formation, full-azimuth reflection angle gathers for a 36-degree opening angle are shown in the image at the bottom left of Figure 2. At bottom right, the accompanying minimum stress fracture orientation map with measured intensity overlies the most apparent brittle zones, shown in rainbow colors.

To map the spatial distribution of the estimated highest brittleness material (versus ductile), the derived seismic attributes, Poisson’s ratio and Young’s modulus were calculated from a simultaneous inversion, calibrated to the well information, and analyzed through advanced cross-plotting methods for geobody detection and mapping.

Interpreting seismic attributes through enhanced visualization techniques, such as advanced merge methods, or through opacity techniques, provides a more precise characterization of the reservoir enhancing predictions of the spatial and temporal conditions of trapping systems, and the distribution of subsurface lithology and reservoir properties. With proper calibration to in situ conditions, observed well trends can be identified and mapped for sweet spot determination.

**UVT Transform**

Unconventional plays have poor reservoir properties and are difficult to interpret from a structural point of view on seismic because of the negligible acoustic impedance contrast, the presence of gas (which degrades compressional-wave im-
aging), or multiple stress episodes. In the presence of faults, which have been reactivated after depositional time, the challenge is even more complex. One approach is to interpret the main, closest, strongest seismic events to the top and base of the reservoir, do some vertical flattening at one horizon, or extract proportional slices conformable to the two main horizons.

The conformable slice extraction is certainly the best approach if the depositional sequence is not complicated by progradation or tectonic events within the interpreted seismic zone. If there is faulting or any internal variation of the sediment depositional sequence, this approach will lead to a misconception of the geologic interpretation. To avoid such interpretational bias, it is possible to validate the interpretation in the paleo-geographic sense at the time of deposition with a change of reference from \( X, Y, Z \) to \( U, V, T \), where \( T \) is geologic time and \( U \) and \( V \) are the paleo-coordinates.

The \( UVT \) transform of the present day structure as defined in \( X,Y,Z \) coordinate space is a paleo-geochronological transformation that restores the \( X, Y, Z \) position of each sediment particle in the \( U,V \) space at the depositional time \( T \). This transform allows a flattening in the \( UV \) space of the interpretation and the seismic itself. It helps the interpreter to better understand the relationship between geological events and validate the structural interpretation.

As a first qualitative approach, seismic data can reveal through waveform seismic facies classification, the extreme heterogeneity that characterizes unconventional reservoirs. Whether unsupervised or supervised, this technique leads to an understanding of the seismic response variability within the reservoir. The correlation at the well location helps illustrate the relationship between local and large-scale homogeneous patterns, and helps show the distribution of the heterogeneities.

Figure 3 shows a seismic facies map paired with a curvature attribute to highlight the heterogeneities of the shale and suggest areas of possible increased fracturing within the Eagle Ford reservoir.

Among the technological developments, the most dramatic is highly parallelized compute power capabilities using graphic processing units to perform computations traditionally handled by central processing units. The hardware's com-
Computation power was first adapted for improved visualization, but it also can be used for on-the-fly calculation to extract post-stack information such as frequency-dependent attributes that can contribute efficiently to an interpretation workflow.

Geometric attributes, including Coherence Cubes®, curvature, fault-enhanced attributes, dip, azimuth, continuity, and/or amplitude variation with offset, impedance and/or other derivatives can be integrated in a technology that supports multipanel, multiattribute interpretation with layering, co-rendering, and interactive cross-plots to provide insights necessary to fully understand shale rock properties in situ.

**Controlling Drilling Risk**

The combination of interpretation, characterization and reservoir modeling, inclusive of all available information with the integration of new technology, leads to better control of drilling risk. It helps to identify and mitigate potential hazards that drilling engineers may encounter by integrating all the information in a unique 3-D canvas. Drilling risk can be mitigated when potential hazards are fully mapped.

Using automated fault-enhanced extraction, the interpreter can perform direct post-stack processing on seismic volumes to reduce noise from the acquisition footprint, enhance discontinuities in the horizontal and volumetric dimensions, extract lineaments along horizontal and vertical slices at the discontinuities (along fault planes), and link the lineaments into fault planes. The ability to investigate both the lineaments and the discontinuities associated with them can provide unsurpassed insight into potential zones of enhanced fracturing/permeability versus areas of permeability boundaries.

Fracture properties such as density, orientation, dimension and spacing are frequently below seismic resolution, but are needed to create fracture models to simulate the effective permeability at a large scale within the flow simulation grid.

As a direct consequence of building a structural model based on the UVT transform, respecting the geomechanical properties of each facies, the proper workflow should consider computing the natural fracture probability in 3-D through generating structural attributes (stress analysis) and creating a stochastic discrete fracture network up to the upscale stage of the fractures to accurately represent the associated porosity and permeability. Integrating all these data to provide reasonable flow simulation results is a powerful quality control tool.

The culmination of reservoir characterization, fracture and flow modeling work is the plan for the drilling operations. Rock property attributes that have been extracted in the interpretation phase of the workflow can and should be used to identify not just drilling targets, but also potential drilling hazards. Figure 4 shows areas of karsting within the Barnett Shale that pose potential drilling hazards. In this case, a fault-enhanced attribute generated by an automated fault extraction module shows the impact of faulting and

**FIGURE 4**
Faulting and Karsts (in Green) From the Ellenberger Formation

**FIGURE 5**
Integration of Horizontal Wells
karsts (in green) from the Ellenberger formation, which intersects the Barnett and poses fluid-loss hazards.

Once log evaluation has been performed in a petrophysical analysis module, the information from each well can be used either to automatically calculate a predictive model directly, or be integrated with the interpreted structural horizons for a more integrated approach. As shown in Figure 5, tighter integration of horizontal wells displaying log templates or tracks along the well path reduces production risk to allow for improved flow rates.

The challenge of producing hydrocarbons economically from low-permeability unconventional plays drives the need for well path and engineering design optimization at every stage of the planning and drilling process. Designing wells within a 3-D structural model that integrates all relevant features can shorten well planning cycle times, improve well placement and reduce drilling risk, while facilitating the decision-making process.

Workflow Steps

The workflows to plan these wells are geared toward a fast turnaround time using conventional software tools. Typically, they involve four steps:

• Using seismic information to locate the seismic horizons associated with the reservoir;
• Integrating seismic data into the geological interpretation;
• Integrating microseismic data to define preferential stress directions; and
• Integrating real-time monitoring of the horizontal drilling with an interactive correction of the deviation.

Understanding in situ stress regimes and reservoir pressure conditions near the projected well is mandatory for the success of any hydraulic fracturing program. The resulting microseismic information will be another source of information to calibrate with the seismic information in an adapted 3-D visualization environment, for time-dependent interpretation of the propagated fractures away from the bore hole. Figure 6 integrates structural interpretation, karsts and sweet spot 3-D geobodies with a planned horizontal well path and targets.

Once the wells have been drilled and completed, production planning and field development planning are critical for optimizing the return on the investment. Microseismic data can provide pivotal information on the success, orientation and extent of the induced fracturing program and rock mechanics, while real-time monitoring of production profiles is a key requirement for field development and production maintenance within these unconventional reservoirs.

Figure 7 shows microseismic data linked to a global time player for animation as knowledge of the real-time flow data and time-dependent completions, productions and simulation data provide keys
to reservoir performance.

The fractured unconventional reservoirs within the Barnett and Eagle Ford Shale have potentially huge reserves that are being targeted aggressively with horizontal drilling and hydraulic fracturing, but rates of productivity suggest there is room for improvement. The subtle nature of the fracturing and facies changes within these plays requires more rigorous full-azimuth seismic processing, imaging, inversion, interpretation and attribute extraction along with integrating well log and microseismic data for physical and geomechanical rock property determination, reservoir and flow simulation, and subsequently, integrated well and field planning to reduce risk and increase production.