Shale gas and oil is becoming an increasingly important source of hydrocarbon production but presents a unique set of challenges to geoscientists who must use the full range of available data to characterise and model shale reservoirs to enable optimum exploitation of these resources.

Shale reservoirs are typically highly heterogeneous in composition and geomechanical properties. To ensure a successful well placement, it is important to know the fluid content, in-situ stress and rock properties in order to find the "sweet spot" that will ensure maximum production.

Along with well logs, microseismic and seismic data can provide very valuable information about these properties at all stages of the E&P workflow. Using specially developed workflows and processing techniques, desirable properties such as shale brittleness and stress can be extracted from the seismic data.

At a Finding Petroleum event, Sandra Allwork, business development manager at Paradigm, talked about how very traditional seismic and well logging data can be used to build up an integrated and complete understanding of an unconventional reservoir such as the Barnett shale.

Discovered in 1981 and located in Central and North Texas, the Barnett shale consists of sedimentary rocks of Mississippian age. The Barnett is known as a tight gas reservoir with low matrix permeability. Its depth ranges from 7,000 to 9,000 ft, and its pay zone thickness ranges between 100 and 1,000 ft. There have been over 8000 wells drilled to date.

The main challenges of a gas shale are low permeability, she said. "In order to be able to realise gas production, we need to identify the zones for hydraulic fracture stimulation (fracking), but at the same time the positioning of that is very important. We need to have careful well placement, and fracturing relative to the collapsed structures, requiring a very good understanding of the subsurface."

Determining shale brittleness and stress is key to planning a successful fracking operation. The brittleness will affect the fluid type that is used, while the closure stress will determine the type of proppant. The best source of information for working out these properties is core data, but this is limited vertically in the wells and won't be available in every well.

"What we are looking at is a way of taking the information from the cores and propagating that out to the rest of the reservoir."

By calibrating core data and well data, knowledge about the reservoir can be extended. Petrophysical modelling can be used to consider brittleness and ductility, and also to look at the kerogen content, which is a measure of the organic content in the shale, a good indicator of hydrocarbons being present.

Seismic data can then be brought in to broaden the horizontal extent of the data and to determine shale thickness and many other rock properties.

Understanding mineralogy

Kerogen content is a good indication of the presence of hydrocarbons, and can be mapped directly from gamma ray logs, spikes in the gamma are related to kerogen content. A Paradigm application called Multimin (Multi-Mineral) can be used to build a model of the different minerals within the well.

Using Multimin, a proposed model of different minerals and fluids can be built up, and the software can then make a prediction of the well data based on the model. By adjusting the mineral content of the model iteratively, the software then tries to match the model to the actual well data by minimising the difference between the two.
Integrating seismic

The interpretation begins with extracting horizons in order to identify formations in the seismic. “The Barnett shale is not particularly interpretable, it does not come out as a huge booming event on the seismic.”

However there are known rock formations, the ‘Marble Falls’ above and the ‘Ellenberger’ below that are easier to see and can help you delineate a zone in between, within which the Barnett shale resides, although it does not occupy the entire zone between the two formations.

As an initial interpretative tool, Paradigm uses waveform propagation to create detailed maps. This is a completely automatic and very efficient technique that can show some of the structural details in the geology.

Another tool called Coherence Cube technology generated an image which can give an idea of the faulting zones within the structure. Together these images can help to identify faulting zones, which need to be avoided. You can also identify karst structures, where the rock has been dissolved by rainwater, which will not hold any hydrocarbons.

“The surrounding structure within the seismic is just as important as the location of the hydrocarbon.” So now you can start to identify areas of interest in the region between Marble Falls and Ellenberger.

Looking in more detail

The next step is to take slices through the data proportionally between the two known rock formations and look at the rock properties within these slices. Paradigm looks at the change in the wavelet shape as it passes through each slice to determine the different types of rock present, and uses a neural network approach to identify facies where the wavelet shape is similar.

Using the well data you already have, you can match up facies in the seismic to zones from the well. This should identify regions that could contain hydrocarbons, as well as classifying other facies which are not of interest.

Alternatively, you can generate a volume classification in three dimensions. This results in a facies cube, within which you can look for three dimensional structures.

These structures can be interpreted automatically using sub volume detection. The software will “detect” connect voxels (three dimensional pixels) that have similar attributes to build up three dimensional geobodies within your zone of interest.

More information can then be extracted from the seismic by mixing attributes visually, more of the structure can be interpreted. Karst collapsed structures can now be automatically identified, building a structural complexity into the model that gives a setting for the shale structures of interest. With the addition of automatic fault extraction, which gives another volume, the eigen volume, further structural details the faults, can be added.

“We are using different ways of extracting information from the seismic and using automated interpretation techniques to extract those so that we can put them into our geological model.”

Full azimuth seismic using EarthStudy 360

The seismic data for the Barnett shale is totally standard, explained Ms. Allwork, but because it is land seismic, it has rich azimuth information and it is therefore possible to use this to determine further properties of the gas shale.

“When we have seismic data, we spend a lot of time working out the best way of decomposing it into different formats that will tell us different things. For example pre-stack data is becoming increasingly important in the interpretation world - people are starting to realise the value of looking at their gather data over just the stack data.”

“In the same way, increasingly we are starting to think about subsurface domain, rather than acquisition domain. So rather than looking at representing a trace by its source-receiver offset, we look at representing it by its reflection angle in terms of the subsurface. We are hoping that azimuth can give us something extra.”
Traditionally, to extract azimuth information, the data would be divided into a number of sectors and the data would have to be processed through the whole workflow individually for each sector. “So the number of sectors is driven by convenience.”

“The resolution of each sector is of course compromised, because you’ve had to make decisions about how to divide the data. Also the integrity of each sector is not preserved. When you divide the data it is by the surface azimuth, but as you trace the rays up from the subsurface the azimuth is not the same.”

But there is another way to process the data. “We can consider the full azimuth decomposition. We work in the local angle domain, and shoot rays up from the subsurface to the surface. Once we have shot a large number of rays up to the surface, we map the arrival rays onto the surface acquisition.”

“So rather than just taking what you have at the surface and just making the best of it down at the subsurface, we shoot rays from the subsurface and collect all of the information and map that to the seismic. We’re illuminating from the depths.”

“This gives us two completely new types of data: reflection data and directional data. The reflection data is defined as the opening angles between a ray pair and the azimuthal variation of that ray pair up to the surface.”

“The directional data is the azimuth or dip of the normal to that ray pair.”

In a traditional sectoring approach you end up with a number of different reflection angles gathers, but with EarthStudy 360 you generate a full azimuth 360 degree angle gather, so you can look at the variation through a full circle.

This gives much more information about stress direction in the shale as you can determine the exact angle rather than only being able to say in which sector the angle lies. This enables the optimal drilling direction to be chosen.

“We are trying to give you the full information from the seismic and allow you to decide what you want to take from that, rather than making that decision before you even start processing and giving you a subset of what originally existed.”

Microseismic for fracture monitoring

With hydraulic fracturing there is a need to closely monitor the operation so that fracture fluids do not leak out and cause environmental problems. “If we are doing fracking then alongside that we need to make sure there is a minimum impermeable layer between the fracking zones and drinking water zones.”

“A very useful way of making sure that this is all safe is to monitor the microseismic data, and we can bring that into the same integrated visualisation environment.”
Paradigm’s EarthStudy 360 generates continuous azimuth, angle-dependent images of the subsurface (full azimuth angle gathers), using the full recorded wavefield to extract high resolution data and information related to subsurface angle-dependent reflectivity without human intervention.

It enables geophysicists to use the entire rich-azimuth data in the local angle domain, resulting in continuous full-azimuth angle-gathers, images and illumination coverage.

Traditionally, multi-azimuth and wide-azimuth datasets are processed and imaged independently by dividing the recorded data into a small and manageable number of offset-azimuth sectors. This type of process is quite rudimentary, especially for long offsets, as it does not properly make use of the entire recorded wavefield. It means that considerable human effort is needed as the individual sectors have to be treated independently and then brought together to make the final model. It also introduces a dependency on acquisition (source-receiver) orientations.

EarthStudy 360 avoids the limitations and approximations associated with azimuthal sectoring of surface recorded seismic data that can compromise subsurface property estimation. Instead, it recovers and subsequently operates on full azimuth seismic data constructed by a proper high-resolution mapping of surface recorded seismic data to common image points.

The continuous azimuth angle gathers generated by EarthStudy 360 can then be used to estimate stress and stress orientation in shale plays, something that cannot be done using conventional surface azimuth sectoring approaches.