With just well logs and seismic data, together with powerful software, you can get a much richer understanding of a shale gas formation you are thinking about fracking, said Sandra Allwork, business development manager Paradigm, speaking at the Sept 20th “Unconventionals” Finding Petroleum London forum.

With nothing more than standard well logs and conventional seismic data, but with powerful software, you can get a much richer understanding of a shale gas formation you are thinking about fracking, said Sandra Allwork, business development manager with subsurface software company Paradigm, speaking at the Finding Petroleum London Forum on Sept 20th “Business Opportunities with Unconventionals”.

Her talk was entitled “Investigating the Barnett Shale: A case study on how integrated technology can help improve your understanding of an unconventional reservoir.”

As a result of the detailed analysis, you can get a better idea of which areas of the subsurface you want to drill into, which areas to avoid, which direction your drilling (and fracturing) should be oriented in, and what types of frac fluids and proppants you will need.

In more detail: you can use the seismic data to get an understanding of the rock properties around the well, and try to identify a “sweet spot” to drill, away from complex rock structures (faults and dissolved rock) that may compromise the efficiency of the frac process.

By using seismic decomposition by azimuth and angles you can identify the best orientation for the bore hole, and the best zone to fracture.

From analysis of existing wireline log data, you can work out the brittleness and ductility of the rock (to know what frac fluids and proppants will work) and calculate the kerogen content (which indicates a high likelihood of gas).

You can analyse microseismic data to get an idea of how far the fracking has actually extended.

Paradigm has a suite of products to perform all of these tasks, including “Geolog” for petrophysical analysis; “SeisEarth” for seismic interpretation, “StratiMagic” for seismic facies classification; “VoxelGeo” for visualising 3D seismic data using voxels (3D pixels); and EarthStudy360 to analyse rock properties in all azimuths (North South East West direction).

Well planning and structural modelling can be carried out in Paradigm’s “SKUA” tool.

EarthStudy360 is the newest of Paradigm’s technologies. “We are still introducing it to the market. The uptake so far has been in the US and we are about to start investigations in Poland,” she said.

Brittleness and ductility
To work out the right frac fluids to use, you need to know the brittleness of the rock (how easily it breaks). To work out what proppants to use, you need to know the closure stress (how hard it will be to keep the fractures open). “We need an understanding of the mineralogy and the mechanical rock properties we’re drilling into,” she said.

Another useful property is ductility (how much a material deforms under stress), which is useful to know when evaluating the seal.

This data can be measured if you have cores (rock samples from the well) in the zone of interest, but these are only available for certain sections of wells already drilled.

However if you have log data, which extends much further along the well, and you have data from nearby wells, you can work out relationships between core data and log data for the section of the well where the core was taken, allowing you to get more information out of the logs for the rest of the well.

“What we’re looking for is a way of getting the information we get from cores and propagating that out, and extracting information from other wells,” she said.

You can get a sense of ductility and brittleness by cross plotting Poisson’s Ratio (ratio of transverse strain to axial strain when the rock is stretched) with Young’s Modulus (a measure of stiffness of the material), using data from the wireline logs, she said.

Kerogen
It is useful to know the amount of kerogen (organic matter) in the rock, which can give you a sense of whether there is likely to be gas in economic quantities.

Kerogen content can be mapped directly from gamma ray logs. High gamma ray activity is thought to be a function of kerogen in the shale. But gamma ray logs have lots of sudden spikes, whilst kerogen content is usually fairly consistent, so the logs don’t provide the whole answer.

Ms Allwork suggests using the Paradigm “MultiMin” rock modelling tool, which can be used to build a model of different minerals in the well. You make a guess of the mineral composition, and see what curves that mineral would produce, and how that compares to the actual curves you get, then adjust your guess until the modelled curves match the actual ones.

You can also use the “Passey Method” which can be used to calculate kerogen content, by overlaying resistivity and sonic curves on a log scale and comparing the
curves.

A further step is to model another ma-
terial in the rock. In the example, Paradigm
added a mineral close to pyrite, an iron sul-
fide often found in coal beds.

So you get 3 different kerogen calcula-
tions, one just using gamma ray, one using
the Passey method, and one adding pyrite in-
to the model.

The end result is a smoother curve, which
looks a like a more ‘robust’ prediction of
the amount of kerogen, she said. “This has
given us a pretty good analysis of the kero-
gen content, the variation of kerogen within
the well, within the zones that have been
logged,” she said.

Seismic

Typically in shale resource plays, the drilling
pace is so rapid, the role of seismic data is
greatly diminished.

The Barnett Shale does not fill the en-
tire subsurface between these formations
above and below, the ‘Ellenberger’, which you
should be able to pick out from the seismic,
which help you in turn in locating the Bar-
nett formation.

The Barnett Shale does not fill the en-
tire subsurface between these formations
above and below so you still need to look
more closely.

For the initial interpretation, Paradigm
uses waveform propagation, an automatic
technique whichpropagates interpretation
according to the trace shape rather than am-
plitude, making it more accurate and pro-
vides interpretation maps showing structural
detail.

Another image is generated by Coher-
ence Cube technology, which can help spot
the major faulting zones. You want to have
an idea about how the shales are fracturing
naturally and, where the major fault zones
are (so you can avoid them). You also want
to avoid karst structures (where rock was
dissolved by rainwater when it was close to
the surface). “The surrounding structures
around the shale are as important as the lo-
cation of the hydrocarbon,” she said.

Seismic

So using information from seismic at-
tributes and rock structure, you can spot ar-
reas which might be of interest.

More detail

Now you can look at the shale in those areas
in more detail.

Paradigm suggests using isoproportion-
al slicing of the area between the Marble
Falls and Ellenberger, which means putting
together slices of the subsurface an even dis-
tance between the upper and lower zones.
You chop the rock up into slices and look at
them all in more detail.

Then you look at how the wavelet
shape changes as it passes through each
slice, using a neural network classification
process. Every change in wavelet means a
change in facies (a change in the specific
rock properties) because each type of rock
(facies) will have its own distinctive wave
trace shape.

Your zone of interest should show up
as a collection of wavelets which look simi-
lar.

If you find a voxel (a 3D pixel in the
data) with a targeted value, the software can
find all the voxels nearby with similar prop-
erties, so you can get a 3D view of the area
you are interested in. So you have a 3D body
of a potential shale zone of interest. Correla-
tions between multiple seismic attributes can
also be carried out with principal component
analysis (PCA), a mathematical technique to
work out which of your seismic attributes are
most useful.

“We’re building a 3D complexity into
the interpretation which will give us the
structural setting for the shale that we’re ex-
ploring,” she said. “We’re using different
ways of extracting information from the seis-
mic and using automated interpretation tech-
niques to extract these so we can put them
into our geological model.”

Angle and azimuth decomposition

An interesting new development from Para-
digm is a software tool called EarthStudy
360 which can analyse the subsurface by
looking at the seismic data rays from any az-
imuth and any angle.

With conventional seismic techniques
rays from the same image point but with dif-
f erent azimuths collect data which are sub-
sequently averaged. As a result of this
process, azimuthally dependent properties
(velocities, rock properties) are lost.

Instead of doing that, Paradigm sug-
gests that you gather together all of the dif-
f erent rays which you think have passed
through your subsurface zone of interest, go-
ing through at different azimuths (North
South East West angles), to get a clearer pic-
ture of what is happening at that point.

The traditional industry method of
working with azimuths is to split the data up
into sectors (usually 6 to 8), for example
North to North West, North West to West,
could each be a sector.

Then you analyse each of them sepa-
rately, so you can see how the end result is
different for each of them.

But if you want to get your fracture in
exactly the right direction, then just know-
ing which of 6-8 directions is the best, isn’t
a very high resolution answer. “The number
of sectors that you divide the data into is
generally driven by convenience. The reso-
lution of those sectors is of course compro-
mised,” she says.

Also this standard 6-8 sector approach
uses the assumption that the azimuth of the
ray travelling from the subsurface to the sur-
face is the same as the azimuth it entered the
subsurface with, which is not necessarily
true.

Paradigm suggests a different method,
modelling the rays in all azimuths all at the
same time. You can model the path of rays
shot from each point in the subsurface for a

Co-visualisation of seismic-derived attributes leads to sweet spot identification
Paradigm calls it “full azimuth imaging and decomposition” – looked at the seismic wavefield in 360 degrees.

“This is a completely new way of organizing data, making it more of an interpretive tool,” she said. “We generate full azimuth angle gathers in depth.”

Then you can work out exactly which directions are best to fracture in, not just the best direction out of 6 to 8 different sectors analysed.

You can also continue your understanding of the subsurface in different directions. “Rather than visualising the data as a cylinder of seismic data, we can look at radiating cylinders out with increasing angle,” she said. “Or we can take the slices round and look at them as more traditional gathers.”

“We’re trying to give you the full information you can extract from the seismic and allow you to make the decisions in terms of what you get from that.”

Anisotropy and fracture density
Paradigm has a number of other interesting processes which can tell us more about the rock properties.

You can do a full azimuth AVAZ Inversion (analysis of amplitude variation with angle of incidence and azimuth), which will tell you about the anisotropic gradient which relates directly to the density of the fracturing.

Anisotropic strength, derived by looking at residual moveout of the 360 degree gathers. A high fracture density is also something to avoid, because your frac fluid can get lost in the existing fractures rather than creating new ones.

By plotting together anisotropic gradient and the fracture density, you can spot areas you want to avoid fracking.

Another interesting process is to invert the seismic and build an impedance volume of P and S (showing how different areas of the rock are interrupting, or impeding, P and S seismic waves). These can be correlated with the P and S impedance logs from the wells.

Using existing well data, Paradigm discovered a relationship between the thickness of the shale layer and the impedance, so mapped that relationship to the impedance volumes - “So now we can start to map the thickness directly from these impedance values,” she said. “That’s another piece of information that we’ve put into the integrated picture.”

**EarthStudy 360TM: Visualisation of a Full Azimuth Reflection Angle Gather gives you detailed Anisotropy data.**

So you end up knowing about which areas of the Barnett Shale have the thickest layer of shale gas, are furthest away from structural activity, and the best way to orientate the borehole.

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**Our conference speakers**

Here are some of the speakers who have given presentations at Digital Energy Journal / Finding Petroleum conferences over the past year:

- Atle Rettedal, Vice President Field Evaluation, **Statoil**
- David Latin - Technical Director, **BP**
- Andrew Grosse - Exploration and Technical Director, **Sterling Energy**
- Gordon Headley, HR manager, **Tullow Oil**
- Sergey Drachev, **ExxonMobil**
- Steve Horton - CEO NewDevCo and ex worldwide Director of Drilling, **BP**
- Jim Green - CIO and GM, Technical Computing, **Chevron Energy Technology Company**
- Angus McCoss - Exploration Director, **Tullow Oil**
- Andrew Lodge - Exploration Director, **Premier Oil**
- Wim Walk - manager geophysics measurement technologies, **Shell**
- Tony Atherton - General Manager, **Talisman Energy**
- Magnus Svensson - IT consultant, **Dong Energy**
- Meyer Bengio - VP petroleum engineering, **Schlumberger Information Solutions (SIS)**
- Rob Pinchbeck, group director of strategy, **Petrofac**
- Jim Farnsworth, COO and president, **Cobalt International** (ex Vice President of Worldwide Exploration and Technology with **BP**)
- Bryan Lovell - Senior Researcher, Earth Sciences, **Cambridge University** (ex Chief Sedimentologist and Exploration Manager with **BP**)

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