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Prediction and productivity improvements in quantitative interpretation via rock physics modelling and interpreter led automation

Martyn Millwood Hargrave, managing director and Dr Jamie Haynes technical director of IKON Science together with Dr Rob Simm of RPA discuss new developments in quantitative reservoir interpretation using rock physics and seismic modelling to give predictive improvements in 3D and 4D workflow and look at the potential for new automated fault interpretation methods to enhance seismic interpreter's capabilities.

The centre stage challenge of modern reservoir geoscience is to integrate quantitative predictions, features and measurements from seismic data into both static reservoir descriptions and dynamic reservoir models through 3D and 4D seismic.

A corollary of both these objectives is the strong requirement for quantitative seismic understanding of the physical properties of overburden, reservoir, seal and aquifer rocks, fluids and the physical effects of changing systems (water flood, pressure depletion, and saturation changes), to build models which can aid interpretation. Finally, geoscientists need to do this with ever increasing speed and precision given the larger number of smaller and more challenging fields needed to replace reserves.

In this article we shall review the evolution and current state of predictive requirements for modern reservoir geophysics mainly looking at the role of seismic modelling in determining where and what to look for in reservoir attributes and optimising workflows, and look ahead to new methods such as automated interpretation that have the power to help geoscientists perform interpretation tasks faster and more quantitatively.

New interpretative technology is the key, and the issue is how this technology can be delivered to interpreters. Automated interpretation processes are starting to have a positive productivity impact. By putting the interpreter in charge of powerful image processing methods that can reduce huge volumes of data to relatively simple patterns, the products can then be more easily visualised manipulated and edited..

In one sense it's time for back-to-basics in the geosciences! After the IT-led integration and visualisation 'revolution' of recent years, now we should be asking how the knowledge base and new technology capabilities fit together to give what reservoir geoscientists need.

Improving prediction of reservoir properties

In this section we are going to discuss some of the factors influencing the potential for rock physics modelling to impact on seismic prediction. Firstly in 4D seismic, then static reservoir description, and finally how the knowledge we acquire through modelling and predictive work can be applied to exploration applications including treatment of exploration risk.

4D seismic modelling

Planning a successful depletion strategy or optimising an existing strategy using 4D depends to a large extent on understanding the specific rock physics and seismic responses of the reservoir in question. Differentiating between genuine 4D seismic effects - pressure, saturation and fluid movements - over other signal and noise in time lapse and difference volumes is a complex task.

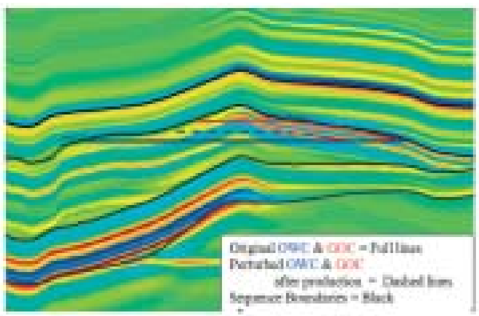

Figure 1 *Synthetic far offset synthetic section through a field being depleted under water injection*

Using predictive rock physics in 4D seismic modelling can help the interpreter in 4 ways:

- Planning special acquisition and processing requirements.
- Determining the optimum seismic attributes to use when looking for 4D effects
- increasing the confidence with which properties and geometries are recognised on real seismic data
- Calibrating the seismic attribute to the physical model and incorporating calibrated attributes in the reservoir modelling.

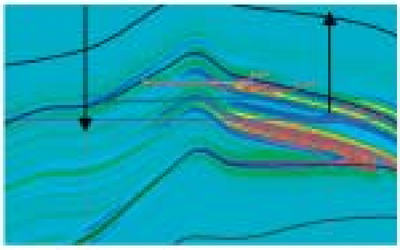

Figure 2 *4D effect created by pressure and saturation changes simulated after production with an injector and producing well*

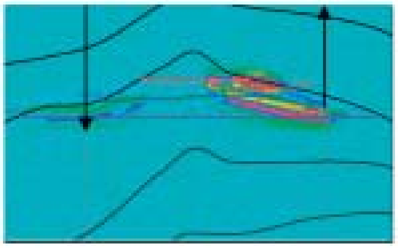

Figure 3 *4D effect created solely by saturation change (after removal of the pressure effects)*

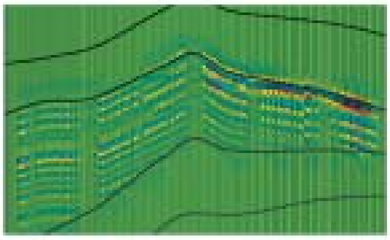

Figure 4 *Noise overprint added to the 4D effects with survey misalignment*

Modelling to separate out true 4D signal from saturation and pressure effects from noise, mis-positioning errors and other artifacts is predominantly a task for the asset geophysicist in concert with the petrophysicist, geologist, and reservoir engineer. The modelling process is important since it trains the interpreter to recognise both quantitative and qualitative seismic effects that can be investigated and added into the interpretation and ultimately into the simulation model.

In the modelled example of figure 3, the pressure effects are larger than those due to moving fluid contacts and residual saturation changes. Figure 4 shows how the complications of noise and misalignment of two surveys can add significantly to the interpreter's problems and highlights the value of modeling in order to allow the interpreter to recognise potential 'signal' characteristics.

Rock physics' modelling is growing fast and new models are being developed to study the effects of many dynamic reservoir factors such as cement weakening, porosity degradation and grain shape changes which can change under reservoir depletion. The move to real time reservoir monitoring will doubtless throw up many new technical challenges

Building the static model

Calibrated seismic attributes are the raw material through which we can accomplish our objective of reservoir characterisation through seismic.

The past 15 years has seen a marked evolution in seismic derived attributes:-

- Relative amplitude
- Relative Inversion
- Absolute Inversion AI
- AVO Analysis
- Absolute Inversion EI
- Projections of elastic
  Properties: - EI /AI
  AI /GI
  LMR projections
  AVOI

We can see evolution has been from map based full stack properties towards true 3D elastic prestack quantities that have the potential to discriminate between different fluid properties and lithological properties. Using seismic attributes to build a valid static model requires a good understanding of the available petrophysics and geology, lab measurements on real rocks, rock physics modelling combining wells and seismic data and geospatial methods of distributing the properties stratigraphically in 3D.

There are a whole host of reasons why we can get the interpretation wrong. These include:

- non-uniqueness of the effects, i.e. other geological scenarios are responsible, e.g. high porosity or low gas saturation
- seismic polarity is misinterpreted
- interpretive problems with seismic data acquisition and/or processing
- predictive model fails, i.e. the assumption that seismic can be approximated as the convolution of a wavelet with a reflection series determined from elastic/isotropic rock properties is wrong. Anisotropy can play a role in giving a 'false positive' indicator. Given the practical problems of parameterising anisotropic models we currently don't know enough about how often this actually happens.

Attributes in the context of risk

In the North Sea, most of the oil fields have been found without exploration being driven by attribute information. There are numerous examples of interpreters spotting the critical seismic effect but misinterpreting it. Later field studies bring to light the real interpretation. What is certain is that attribute technologies are now adding considerable value in field development, owing to the high degree of calibration available.

Whilst the challenge is always there to use the lessons from the fields to drive the exploration models in partially explored basins, it is easy to convince ourselves that we know more than we actually do. Very often if a well is available, there is a tendency to believe that it contains all that is necessary for calibration, including all likely variability. The problem then is to ask ourselves - 'what is the likelihood that the model will hold over the prospect area?' In some cases significant changes can occur to invalidate close well control (often in field development) whilst in other situations a well 50 km from the prospect may be entirely relevant.

Calibration between well and seismic data is clearly the key to the application of seismic attributes in risk. Our models are only as good as the data on which they are based. In virgin basins where there is stratigraphic uncertainty and no calibration, it may be completely unrealistic to try and apply direct hydrocarbon indicators (DHIs) in the risking process. In such areas conventional AVO analysis can give us an idea of the degree to which different responses are anomalous. But it can't tell us how likely a particular seismic effect will be related to hydrocarbon rather than, for example, a high porosity brine sand (or any other as yet undefined lithology combination for that matter). At best - and if you are lucky enough to have a number of potential prospects - it can be used as a ranking tool.

Assigning risk to DHIs

Very often we don't have the statistics to support the risks applied to DHIs, usually because we are trying to apply the techniques in non-mature areas. And when it comes down to it, whichever way you assign risk significance to DHIs, it is highly subjective. Fundamentally it depends on the level of knowledge of the play and an understanding of the particular DHI characteristics of the target. With greater knowledge of the play, the vagaries of the DHI signature and its relationship to factors such as data quality are likely to be more completely understood. Two companies may recognise the same seismic effects but place different significance on them simply because of differences in the understanding of the play

Many companies have attempted to formulate a way of incorporating geophysical observations into risking systems. A generic (and non-specialist) approach might be to use the risk matrix idea of Citron and Rose (2001) but in which the axes are related to the knowledge of the play (in terms of the seismic responses of lithology and fluid, calibration if you like) and the confidence in the recognition of the DHI(s).

Low		High	Knowledge of Play
N/A	20%	50%	Good
N/A	10%	25%	
N/A	N/A	12%	Poor

Confidence in DHI

Figure 5 *An example of a chance of success matrix based on DHIs .*

Ways forward with attribute interpretation

Effective DHI interpretation requires rigorous analysis and a cross-discipline understanding of what attributes can and can't do for us. Non-specialists (i.e. most geophysicists, geologists and increasingly managers and engineers) need to be able to ask the right questions to put the seismic information into context. This would help communication and ensure that the geophysical interpretation is done in the most rigorous way possible. This technology transfer can only happen if:

- There is a greater general understanding and access to seismic analysis techniques linked to calibration methods, including rock physics, and their limitations, via training and accessible technology.
- There is access to a knowledge database of previous examples, the good, the bad and the downright ugly, and lessons learned from that database.

Established training courses can go some way to achieving this, but there has to be an active mind-set within each company to synthesise past experiences into 'learnings' that are made available to those who need them. The value of the knowledge database should not be underestimated and it is never too late to begin the process of developing it. What is not enough is for the geophysical priesthood to simply write guidelines and prescribe expert-authorised workflows. They do not ensure communication and in the worst cases can actually stop people thinking!

The following example shows how rock physics was used to model the presence of a Late Jurassic mass flow sand reservoir (the Buzzard Ettrick sands in the UK Central North Sea). By predicting its elastic seismic properties, seismic modelling of these effects can predict work flows to use in processing and interpreting 3D attribute volumes when looking for analogues and new plays.

Mass flow sands like Buzzard can be of excellent reservoir quality as is shown by the CPI plots for well 20 / 6-2 (Figure 6) which shows the high net to gross of the proximal

Buzzard Ettrick sand system.

A rock physics study of these wells was performed including, invasion corrections, determination of dry rock moduli, and Gassman fluid substitution from brine-filled to oil-filled concluding with a comparison of modelled elastic parameters to determine the most effective predictor of hydrocarbon filled sands and, if possible, the highest net pay. The attributes examined included AI, EI, LMR attributes and an attribute combining AI and EI called AVOImpedence.

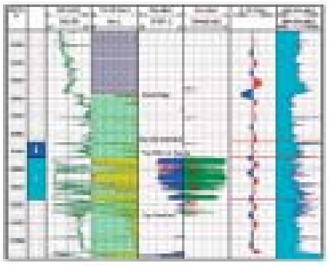

Figure 6 *Well 20/6-2 petrophysical analysis*

The comparative analysis showed that AVOImpedance (a projection based on EI and AI) was ranked highest as the most discriminating predictive attribute both for presence of oil fill (Figure 7) and predicting hydrocarbon net pay (Figure 8).

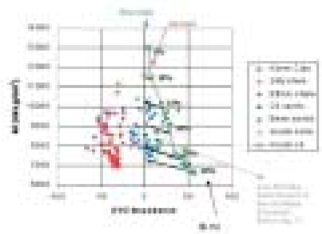

Figure 7 *AVOI oil-filled sand discrimination template*

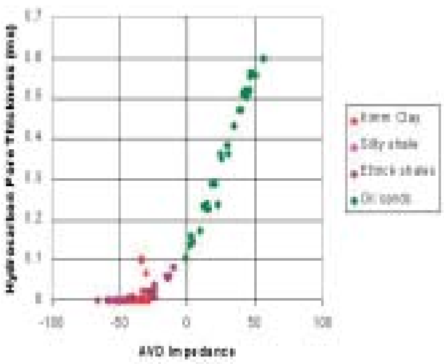

Figure 8 *Net pay from AVOImpedence*

The rock physics models can be extended to 2D by incorporating the typical up dip pinch out geometry of the Buzzard Graben into the RokDoc Scenario package (Figures 9 & 10).

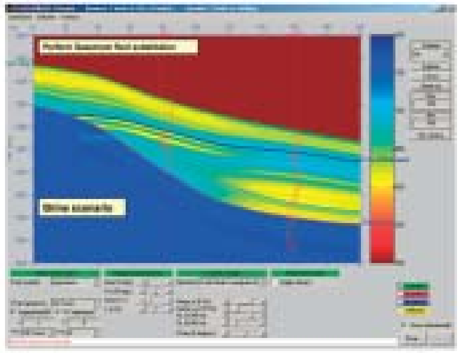

Figure 9 *Buzzard type model brine filled viewed as elastic impedance model (EI).*

The test of modelling and rock physics of course is whether these effects can actually be detected on real seismic data with all the attendant problems of noise and variable data quality. Having a 2D or 3D model allows direct comparison with the seismic attributes themselves.

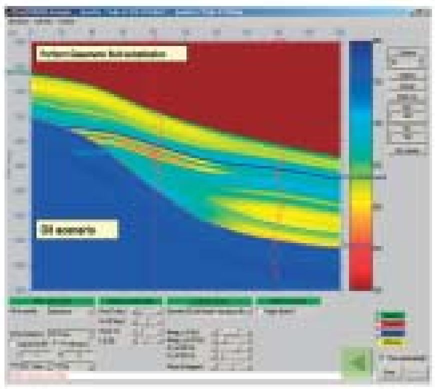

Figure 10 *Oil-filled sand models*

Figure 11 shows the results of inversion of a 2D seismic line to the AVOImpedence attribute predicted by visual modelling and rock physics to be the best attribute on which to discriminate and interpret lithology and fluid-fill.

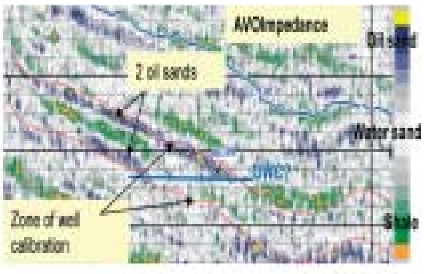

Figure 11 *AVOImpedence inversion*

The seismic inversion result clearly shows the two oil-filled Buzzard sands (blue/ yellow) separated by shale (green/brown) and terminating at a common oil water contact. Further, it has discriminated this positive result from the brine-filled case at the 20/6-2 well to the left of the section!

The next wave: automated interpretation methods increase productivity

With a diminishing and aging work force and more well, seismic, and real-time reservoir data being collected to analyse, there is a clear need to streamline workflows and increase the speed of analysis and interpretation. This is not a problem which is confined to the reservoir geoscience business. For instance in medical science the use of magnetic resonance imaging (MRI) and functional magnetic resonance imaging (FMRI) has given rise to an explosion of digital image data analogous to the explosion of 3D and 4D seismic data into our industry. Just like seismic data, this data needs to be interpreted and risk reducing decisions made using the data if it is to be justified as cost effective

Fault picking: notoriously tedious and repetitive

How much time do interpreters spend on interpreting faults in a typical project? Clearly this is dependent on the intrinsic structural complexity of the project area, the seismic data quality, the objective of the interpretation and the time available. A recent survey we conducted posed the question: 'How much time do you spend in interpreting faults in a typical project?' The respondents replied with a range from 10% to 75% of total project time. For interpreters working the North Sea and Gulf of Mexico, the range was from 30%-60%. For interpreters building detailed 3D models of fields the range was from 40%-70%. In the survey fault picking was perceived as extremely tedious and repetitive. It is the kind of activity that cries out to be automated in order to release time for more evaluative and creative interpretation tasks.

Problems of automating fault interpretation

Conventional manual seismic interpretation methods on 3D data use a mixture of disparate visual clues and mental models to recognise and interpret faults. These include direct fault plane reflections and diffractions, changes in reflector continuity, offsetting patterns in reflector shape either side of a fault and subtle amplitude and phase changes. Good quality seismic data is a major help as is interpretational experience including a good knowledge of structural geology and tectonics. In general it is difficult to produce globally applicable rules for identifying individual faults and combining them to produce a coherent fault pattern. Developing robust algorithmic approaches to automating the fault interpretation process, therefore, is not trivial.

Fault methodology

Geoscientists at IKON Science have developed a robust software workflow which has been applied to data from a wide variety of settings and data quality with good results.

3D seismic reflectance data is processed to enhance the characteristic discontinuities. There are a number of methods to achieve this including 3D-dipAzimuth, Manhattan difference algorithms, and combinations of single attributes to produce special meta-attributes.

Image processing methods initially developed in medical applications are applied to isolate and detect fault-like features. The interpreter can then apply statistical filters, 3D visualisation, and user controlled analysis to pass or reject potential fault candidates (Figure 12).

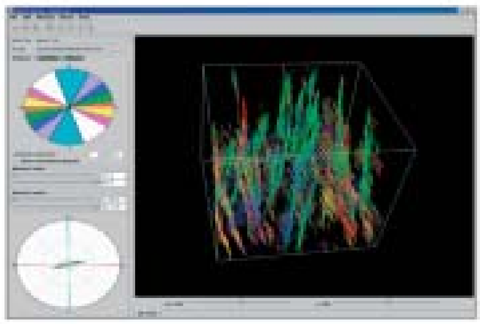

Figure 12 *Auto picked faults colour coded by azimuth*

Candidate fault planes can be produced and then modified, joined, and expanded until the interpreter is satisfied. The fault model is output into a modelling system, conventional interpretation environment, or visionarium (Figure 13). Results show that the process is robust in the presence of noise and can typically reduce the time taken for fault interpretation in a North Sea or Gulf of Mexico setting by an order of magnitude. In a typical project it can save weeks or even months of interpreter time.

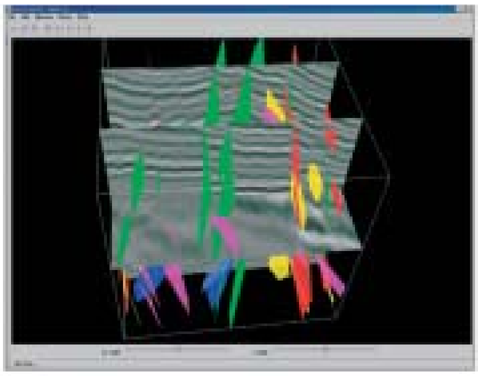

Figure 13 *Auto-picked fault planes superimposed upon original reflectance data for interpreter QC*

In a typical oil company environment where interpreters at best may spend less than 50% of their time doing interpretation, the relative saving and productivity increase will be much more so that time saved can start to seriously impact and improve project economics. Other benefits are the objective and repeatable nature of the process and the quantitative nature of the results which may enable advances in understanding of other spatial properties, such as anisotropy and stress.

Summary

The value adding process that reservoir geoscientists can uniquely make has to come from new interpretation technologies. i.e. creative ideas from within the science that will generate the next leap forward. We believe that rock physics modelling and automated interpretation methods offer this potential for reservoir geoscientists by improving seismic prediction on the one hand and unlocking interpreters from the drudgery of manual Intepretation methods on the other.

Acknowledgments

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