'There are of course a myriad of issues and frustrations for E&P geoscientists in trying to optimize the value of seismic data and no one company has all the answers.'

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Why anisotropy can no longer be ignored

Andrew McBarnet reviews one of the current seismic imaging methods being applied to resolve the distorting effects of anisotropy in the Earth's surface.

From time to time it is salutary to be reminded of the complexity of the issues routinely facing oil industry geoscientists in their efforts to unlock the secrets of the subsurface, not to mention the constant improvement in the technology. For example, we all too easily take for granted the astonishing progress made in the processing and interpretation of 3D seismic data.

Yet every geophysical services contractor has to at least keep pace with the competition in providing solutions, and preferably have some special methods of their own which can differentiate them from the opposition. Companies with sophisticated packages to enhance basic acquisition survey data can greatly increase the value of deliverables to oil company clients.

As a company which focuses on offshore multi-client seismic survey data, TGS-Nopec Geophysical Company (TGS) has in recent years substantially increased its data processing capability in order to be able to add value to the product that it can offer. These days it has almost come as an expectation from TGS client companies that they will receive a highly informative dataset which has benefited from some advanced imaging techniques.

There are of course a myriad of issues and frustrations for E&P geoscientists in trying to optimize the value of seismic data and no one company has all the answers. In the case of TGS, the company has devoted considerable research time on how to deal with the phenomenon of anisotropy and better ways of measuring its effect on the data acquired during a seismic survey. In some cases the pay-off for improving the quality of the data in this way is a dramatically more accurate idea of the physical location of the subsurface images. This has in the past always been problematic, involves a lot of calculation and is by no means an exact science.

TGS says that its latest technique will be applied to its multi-client survey activities, but also to data submitted to them by any interested companies. It is regarded as being particularly useful in the development strategy of mature provinces where the reservoirs may be difficult to image, and often tend to be deeper and smaller in size. Any extra precision in the reservoir model is therefore invaluable in the positioning of production wells to optimize oil and gas recovery. The anisotropy work is also very relevant to the modern exploration era.

New survey methods using long offsets and wide-azimuth are identifying previously elusive targets, such as below the subsalt in the Gulf of Mexico, which need all the illumination that geoscientists can conjure up.

Compelling results

To prove the point, the company has recently undertaken what is thought to be one of the largest ever projects incorporating what it calls anisotropic parameter estimation, together with some other proprietary processing magic. It believes that the results are compelling enough to demonstrate that anisotropy can no longer be ignored in the processing of modern 3D data.

The background to this innovation stems from the physical observation that waves propagate at different velocities as a function of their orientation within a medium. This is called anisotropy. A solid that does not exhibit this phenomenon is called isotropic. In geophysical exploration seismic waves used to image the subsurface travel through the earth and are reflected and refracted at sediment interfaces (because the sediments have different velocity and density effects on the waves). The returning signals are what are recorded at the surface. By measuring elapsed time from when the seismic signal is generated (for example, by an air gun shooting off a seismic vessel) to the time

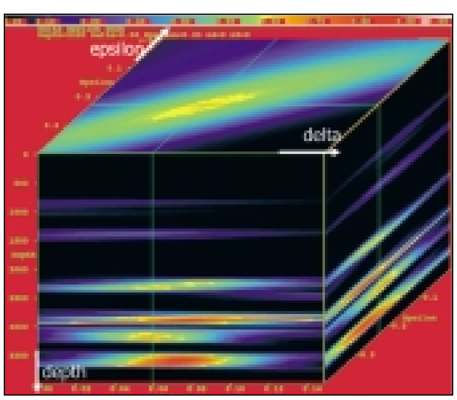

Figure 1. *Depth domain Epsilon and Delta.*

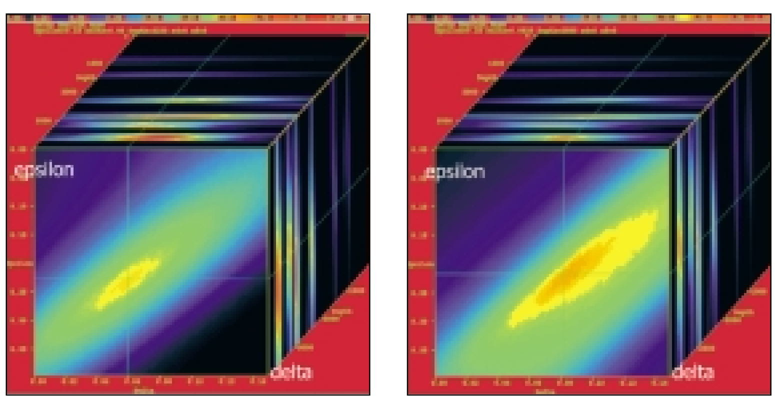

Figure 2. *Epsilon and Delta auto-pick.*

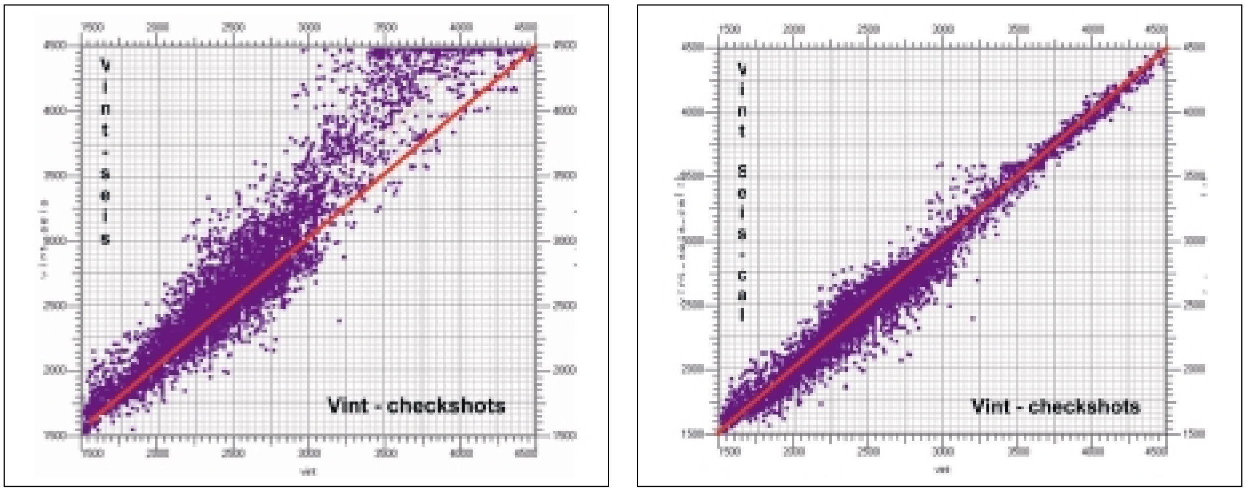

Figure 3. *Well checkshot velocities versus seismic interval velocities (left) before and (right) after calibration.*

when it is received, so-called seismic velocities are inferred.

Just to complicate matters, the Earth's subsurface is in general anisotropic. This means that seismic waves travelling in one direction relative to a vertical axis are going faster (or slower) than in other directions, an effect which varies aerially and with depth. Up to now geoscientists have usually got by without measuring the orientation of the reflected wavefield and have just accepted the imperfection.

Part of the attraction of multi-component acquisition is that it can in theory address this issue. The method attempts to provide the proper azimuthal (directional) distribution of receivers by placing a hydrophone and three geophones with a vertical and two horizontal components at the same receiving point.

In this way it is possible to discriminate between reflected waves.

Onshore multi-component recording has been found valuable for detection of fractures which affect the permeability of reservoirs. The downside for marine seismic is that some form of ocean bottom acquisition is required deploying receiver cables or nodes on the seabed. This concept has not attracted much industry interest mainly on grounds of uncertainty about the cost benefits, so remains very much a niche market.

The vast majority of 3D marine data continues to be derived from non-directional hydrophone arrays in streamers towed behind vessels.

Need to define

Since the 1980s there have been some in the geoscience community who have argued that the influence of anisotropy cannot simply be ignored even if its impact on imaging accuracy has been deemed insignificant. Leon Thomsen, a renowned geophysicist now at BP, is credited with being the foremost proponent of the need to define the amount of anisotropy within the earth and how these parameters could refine the velocity models used to stack and migrate seismic data in time and depth. His anisotropy parameters 'epsilon', 'delta' and 'gamma' first promulgated in a 1986 paper are now part of the accepted technical vocabulary, and his work has been acknowledged as important in promoting the role of geophysical applications in defining reservoirs.

Following in the footsteps of Thomsen and others, TGS believes that anisotropic parameter estimation can be significant for modern seismic acquisition data. The company's interest dates back to the 1990s when the use of long offset 2D marine seismic was introduced. This involves the towing of a single streamer of between 6000m and 10,000m to image complex geology, for instance, below subsalt structures in the Gulf of Mexico and some regions of the North Sea.

In processing long offset data it was found that some correction was needed for the effect of anisotropy at far offsets which up until then had been ignored or, worse still, simply 'muted out' as noise.

One of the first practical applications that corrected for anisotropy in seismic data extended the useful offset range of unstacked CRP (common reflection point) gathers in order to analyze the signal amplitude variation with offset (AVO), an effect successfully used as a hydrocarbon indicator for nearly 30 years. Several methods were implemented to measure and correct for the higher order (non-hyperbolic) curvature of reflected data. Anisotropy was characterized by the so-called 'hockey stick' effect at higher angles.

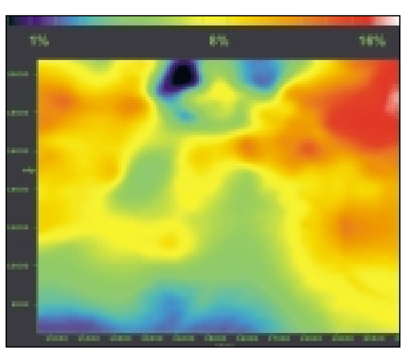

Figure 4. *Percent depth error at 6000m.*

Unless well information with secondary (s) shear wave data (as opposed to primary (p) compressional wave data) was available, this only gave an estimation of the 'eta' factor combining the epsilon and delta parameters defined by Thomsen, rather than providing a separate measure of each. S-wave data can only be acquired with the use of geophones on the seabed (ocean bottom seismic), while towed streamers only provide p-wave information.

The natural extension of AVO to 3D data followed, and a number of factors once again pointed to the need to properly correct for the anisotropic effect. For example, more accurately positioned data due to improvements in migration techniques and better velocity model building techniques revealed the anisotropic flaw.

Kirchhoff and Wave Equation 3D pre-stack time migration algorithms were also becoming more efficient and accurate. In the case of Kirchhoff implementations, the processed long offset data was able to image very steep dips, salt flanks and even 'overturned' geological events such as those encountered in salt overhangs. Furthermore, while the data was still being largely interpreted in time, the errors between the depth converted seismic (using migration velocity models) and well logs were becoming harder to ignore. This scenario had to be addressed given that prospects were getting smaller in size, deeper and harder to image in complex geologic settings.

Increased benefits

In recent years exploration in mature basins such as the Gulf of Mexico have benefited increasingly from the availability of 3D prestack depth migrated (PSDM) data covering large areas, a highly computer-intensive operation once the preserve of a few specialist companies. Interpretation is now routinely done on 3D PSDM volumes that may be second or third generation versions of the same data that have been migrated using both Kirchhoff and Wave Equation algorithms and been through several iterations of velocity model building/interpretations.

Supra and subsalt tomography techniques have also allowed more precise velocity models to be built thereby also contributing to improved imaging around and under salt.

Since time to depth migration algorithms need input from a velocity model, they can normally handle the anisotropy effect but only if the epsilon and delta parameters are known. Otherwise some distortion occurs.

The motivation to effectively estimate the anisotropy parameters with a good degree of accuracy became a priority for TGS. In real life, geoscientists and reservoir engineers have found seismic data identifying drilling targets as much as 5-15% deeper than indicated by the well logs. A bigger concern was the degree to which the anisotropy may distort the actual relief and size of the prospects, and also the apparent thickness of salt bodies. Such issues can have a huge impact on the profitability and economic viability of a project.

Cracking a way of estimating the epsilon and delta values has been a major challenge for TGS knowing that, without some means of calibrating the anisotropy to a minimum of well information, the estimates remain essentially guesswork. The company first developed a proprietary 3D depth model epsilon and delta scan from image gathers as depicted in *Figure 1*. These provide the values that yield the best stack data. The key, according to TGS, lies in the ability to scan the epsilon and delta values from a 3D cube and auto-pick these in depth (*see Figure 2*).

With these parameters in place it is possible to 'correct' the velocity model and provide the percentage degree of error from the initial velocity model uncorrected for anisotropy.

This methodology was applied recently to a 3D data set covering about 660 OCS blocks (15,000km^2) in the Mississippi Canyon area of the Gulf of Mexico. The survey had been previously 3D depth migrated in 2005 using shot based Wave Equation PSDM. The velocity model, however, was derived from a one dimensional (1D) update and no anisotropy was included in the migration.

To ensure the validity of the anisotropy parameter estimation, 247 wells within the survey were also included. The checkshot logs were also extrapolated to 16km to match the data length. A measure of the correction was checked by plotting the interval velocity from the checkshots (as scatterpoints) vs first, the uncorrected seismic interval, and then with the corrected seismic interval. If the calibration was successful this would put the well points on a 450 line on the plot. The plot before calibration showed the expected deviation (seismic velocity being 'faster'), while the plot after correction showed a strong correlation between the velocities (*see Figure 3*).

An example of the percent error in velocity due to anisotropy at a depth of 6000m is depicted in *Figure 4*.

In addition to the anisotropy parameter estimation, the data set benefited from several iterations of tomography (both above and below salt). This coupled with revised interpretation to include second top and second base of salt provided a much better velocity model for the migration step. The Kirchhhoff algorithm employed was a VTI implementation (transversely isotropic medium with a vertical axis of symmetry).

One of the major goals of this reprocessing effort was also to provide an improved dataset to the exploration community in time for the 2008 March Central Gulf of Mexico lease sale. Using the process described, the project was completed on time but it took six months to complete, emphasizing the scale and complexity of the undertaking, a fact of life in the super-computer world of seismic data imaging.

TGS measures the project's success according to the objectives it set out at the beginning which were to generate a better tie between the seismic data and available well information using anisotropic migration, enhance the steep-dip imaging, improve the velocity accuracy using tomography and to provide a velocity model for future surveys.

According to the company, *Figure 5* and *Figure 6* provide a good illustration of the improvements that were achieved in the reprocessing of the Mississippi Canyon 3D dataset. The previous isotropic prestack depth migration while quite good was not able to image the steep dips around salt as well as the anisotropic Kirchhoff effort. More importantly, this was a mature basin with extensive development, so the reservoir engineers and development geoscientists needed more accurate images with data that tied the available well information in order to plan future wells. In Figure 6, the data ties with the gamma ray (GR) and checkshot survey (VEL) log are very good. The previous data was off by as much as 4000ft at the Oligocene-Eocene target. In the view of TGS, such improvements are worth striving for and must make sense to oil companies in terms of the potential additional reserves which might be recovered. **OE**

● *In the preparation of this article, input from* **Frank Dumanoir**, *TGS-Nopec marketing manager – imaging services, is gratefully acknowledged.*

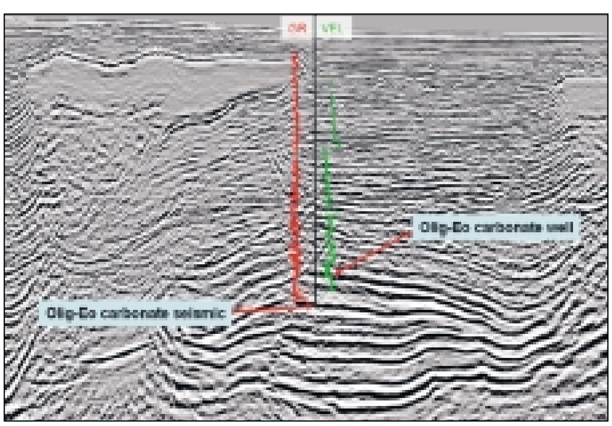

Figure 5. *Isotropic PSDM. Seismic does not tie well log.*

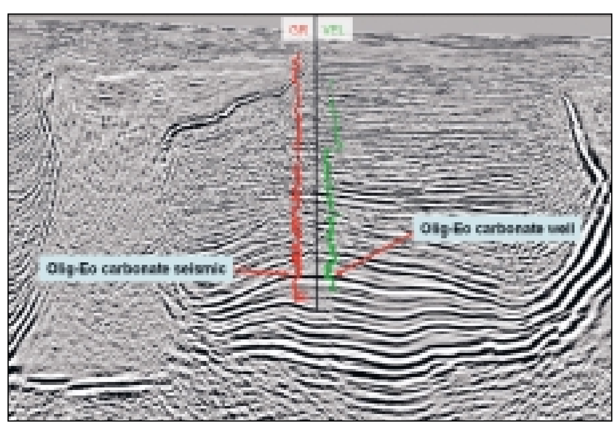

Figure 6. *Anisotropic PSDM. Seismic matches well log.*