More accurate reservoir imaging through anisotropic pre-SDM

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Introduction

Prestack depth migration is recognized by the industry as a tool to be used where strong velocity variations are known to exist. However, for the vast majority of oil and gas fields that lie beneath conformable and generally flat overburdens, prestack depth migration is not currently considered to be a necessary tool. This attitude is not surprising because the isotropic prestack depth migrations performed to date have shown a lack of precision. The seismic data produced in depth by these migrations rarely tie the formation depths that are observed in well bores. If the depths do not tie, the interpreter has to question the lateral accuracy of the fault positioning.

The reason for the depth mis-ties between well and seismic has for a long time been recognized to be caused by assuming the earth to be isotropic rather than the anisotropic reality (Banik 1984). The effect of anisotropy on the seismic wavefield has been defined over the years by various researchers e.g. Thomsen in 1986. This work introduced the anisotropic parameters δ, ε & η that, when used with an axis of symmetry, define the propagation of a seismic wavefront. During recent years, the industry has started to see the practical use of anisotropy in seismic imaging. We use material from case studies to show that better accuracy is being achieved and propose that there is a strong case to use the technology routinely on all mature reservoirs.

Anisotropy discussion

The difference between isotropic and anisotropic media is that the former has a velocity that is the same for all directions, whereas the latter has a velocity that depends on the direction of propagation. If the directional dependency of the velocity is symmetrical about a single axis, then the media is described as exhibiting transverse isotropy (TI). Furthermore, if the axis of symmetry is vertical, then the situation is described as vertical transverse isotropy (VTI). Similarly, a horizontal axis of symmetry would be described as HTI. The general case in which the axis of symmetry is neither vertical nor horizontal is known as tilted transverse isotropy (TTI). Defining the correct axis of symmetry is a fundamental requirement for accurate anisotropic imaging. Having defined the axis of symmetry one can complete the description of the seismic wavefield by estimating anisotropic parameters δ & ε (Thomsen 1986). Figure 1 illustrates an isotropic wavefront and two anisotropic wavefronts with differing axis of symmetry. All of these wavefronts would have been estimated from the same seismic data using different assumptions i.e. isotropic, VTI and TTI. In the case of many structures, a correct axis of symmetry assumption is as important as accurate δ and ε parameter estimates. This is particularly true for Central Graben diapirs, as will be shown.

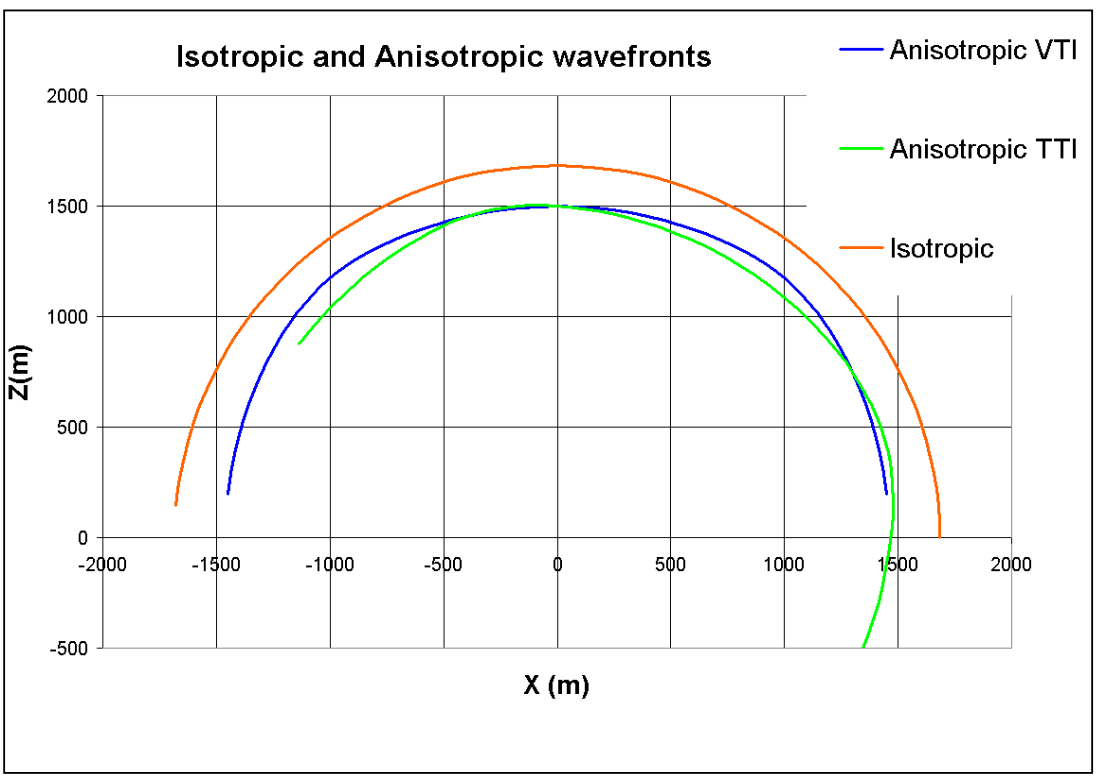

Figure1: A comparison of isotropic and anisotropic wavefronts that could be derived from the same seismic data using three different assumptions; Isotropic, VTI & TTI.

An excellent way of quality controlling the anisotropy parameter selection is to utilise walkaway VSP information where it is available. In Figure 2, the first arrivals of such a walkaway VSP are compared to isotropic and anisotropic ray-traced travel times produced using a well consistent velocity model.

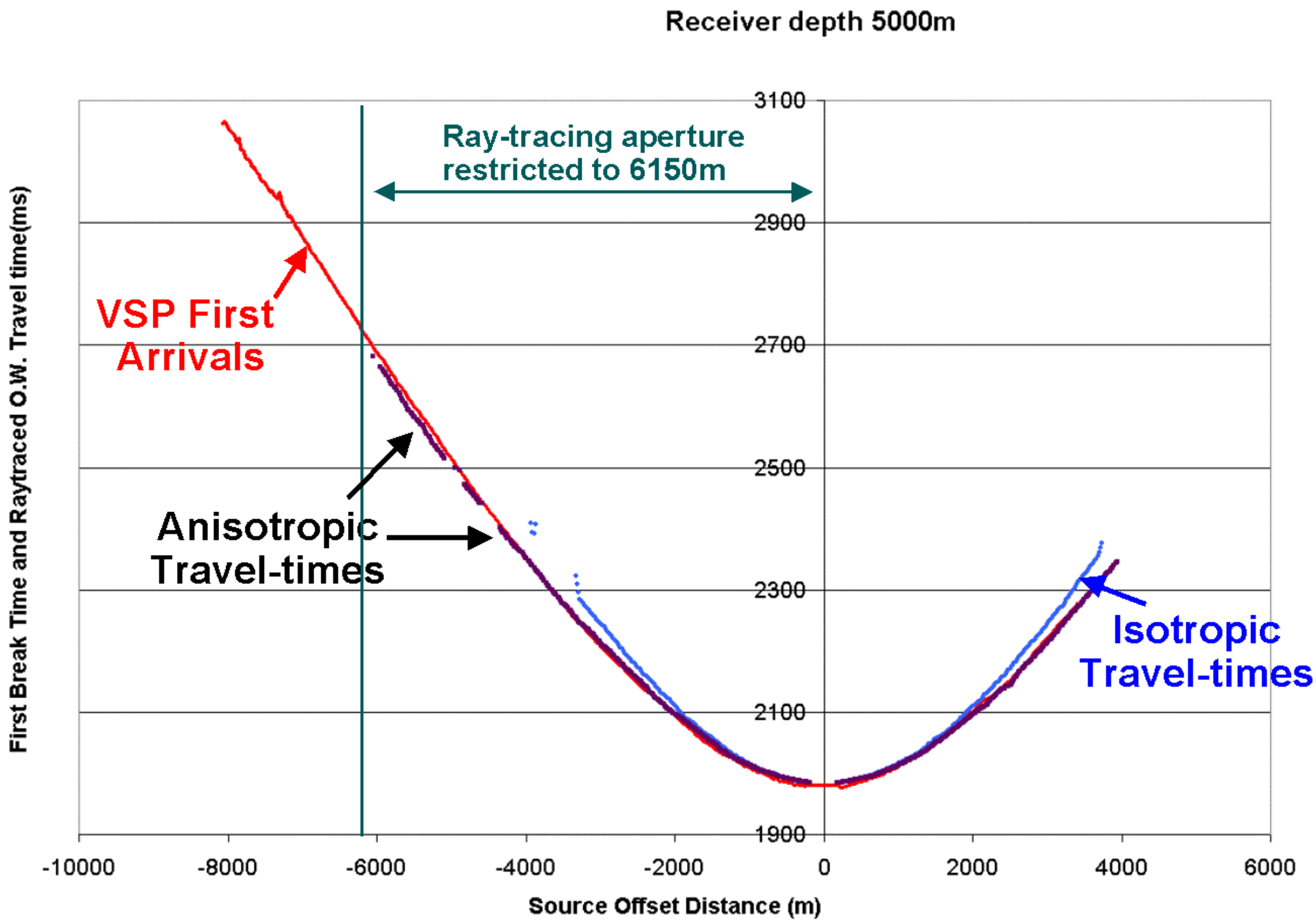

Figure2: A comparison of walkaway VSP first arrivals with anisotropic and isotropic ray-traced travel times. This example is from the Central Graben of the UK sector of the North Sea.

A common concept is that anisotropy is associated with shale. While shale is anisotropic, it would be a mistake to assume that it is the only anisotropic material. In Figure 2, the difference between the anisotropic and isotropic travel times will be shown to be mainly due to anisotropy within the Cretaceous Chalk of the Central Graben in the North Sea.

The benefits of anisotropic prestack depth migration

Anisotropic imaging is performed with velocity models constrained to known vertical well velocities and anisotropy parameters that produce flat image gathers. Isotropic imaging uses only unconstrained velocities to flatten image gathers. The former, with its extra constraint, should provide a more accurate estimation of true wavefront propagation. This leads to better imaging, depths consistent with wells and accurate lateral positioning.

Figure 3 shows a comparison between a reservoir imaged with isotropic and anisotropic depth imaging. The reservoir is under an overburden that has been made complex by salt tectonics. The difference in the detail of the reservoir between the two images is significant. On the anisotropic image, the Top and Base Salt markers posted on the intersecting well bore show a salt thickness of just 21.4 metres, in good agreement with the seismic image. Those same markers are approximately 300 metres above the top of the isotropic image. Some vertical lines drawn at a fault close to the well illustrate that there is also a lateral movement of about 75 metres between the two images.

Many in the industry are looking to the integration of seismic and time lapse seismic with well log data to help characterise reservoirs. This will only be really effective if the reservoir characteristics and time differences are put in the right location with correct anisotropic migration.

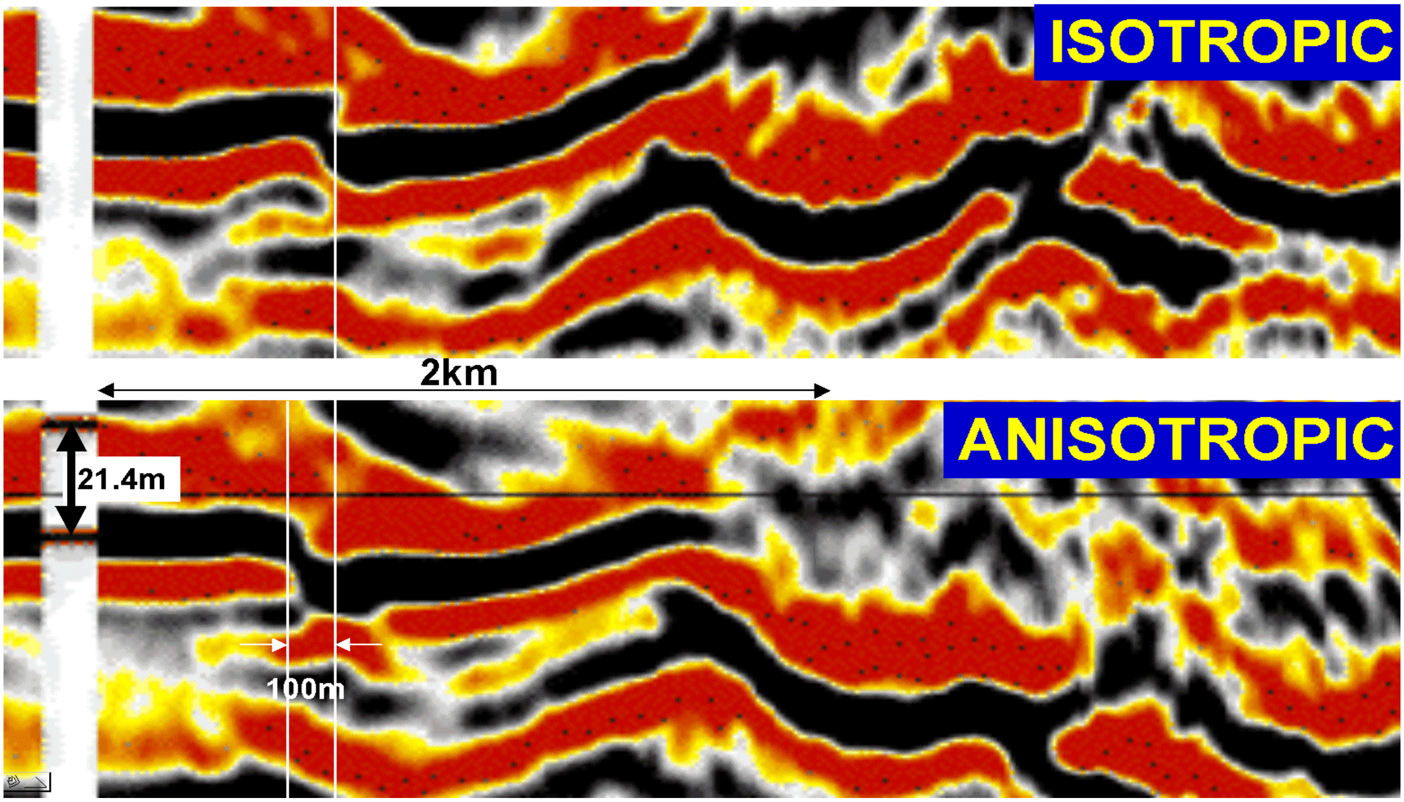

Figure 3: A reservoir comparison at a well location between isotropic and anisotropic depth imaging. The depth of Top and Base Salt is posted on the well bore on the anisotropic image illustrating a good tie. The depths of the two seismic depth images differ by ~300 metres while fault positions appear to differ by ~75 metres.

Another benefit of introducing anisotropy is that much greater emphasis is placed on incorporating well data in the velocity-depth model. This includes the depths of formation tops from deviated wells. In many mature fields, deviated wells are more numerous than vertical wells. The prohibitive cost involved in acquiring vertical VSPs for deviated wells often means that formation tops are only known accurately in terms of depth. The enhanced depth accuracy of anisotropic migration enables optimal use of these deviated well formation tops. Figure 4 shows an anisotropic image along a from the Dutch sector of the North Sea being quality controlled by wells, including deviated ones. The line has two bends in it so that it ties the deviated wells as they penetrate the Base Salt.

The A7 well encountered very fast hard dolomite within the Salt immediately above its base. No attempt was made to model the isolated dolomite and the use of a constant velocity throughout the Salt resulted in a depth error of 20m at this well. The other wells did not encounter any significant dolomite and they tie the seismic depth.
Well L2 was known to have penetrated a fault at Base Salt. This fault is also observed on the seismic right at the well location confirming the lateral accuracy of the image. These positioning errors are much smaller than those encountered using isotropic imaging. While the lateral accuracy is totally dependent on the accuracy of the imaging scheme, the relatively small depth errors can be further reduced with the same calibration techniques that are routinely implemented to improve well depth ties after isotropic imaging.

Conclusions

- The earth is an anisotropic medium for seismic wave propagation.
- Isotropic prestack depth migrations will never be correct and will always produce inferior reservoir images. The error in these images will be difficult, if not impossible to quantify.
- Anisotropic prestack depth migrations performed with incorrect anisotropy parameters or axis of symmetry will also be erroneous. It is conceivable that the positioning errors could become as large as those that occur with isotropic imaging.
- The accuracy of anisotropic prestack depth migration should be limited only by our ability to correctly interpret well, geologic and seismic data. Only time and more case studies will demonstrate how easy it is to make those correct interpretations and demonstrate our competence as geoscientists.

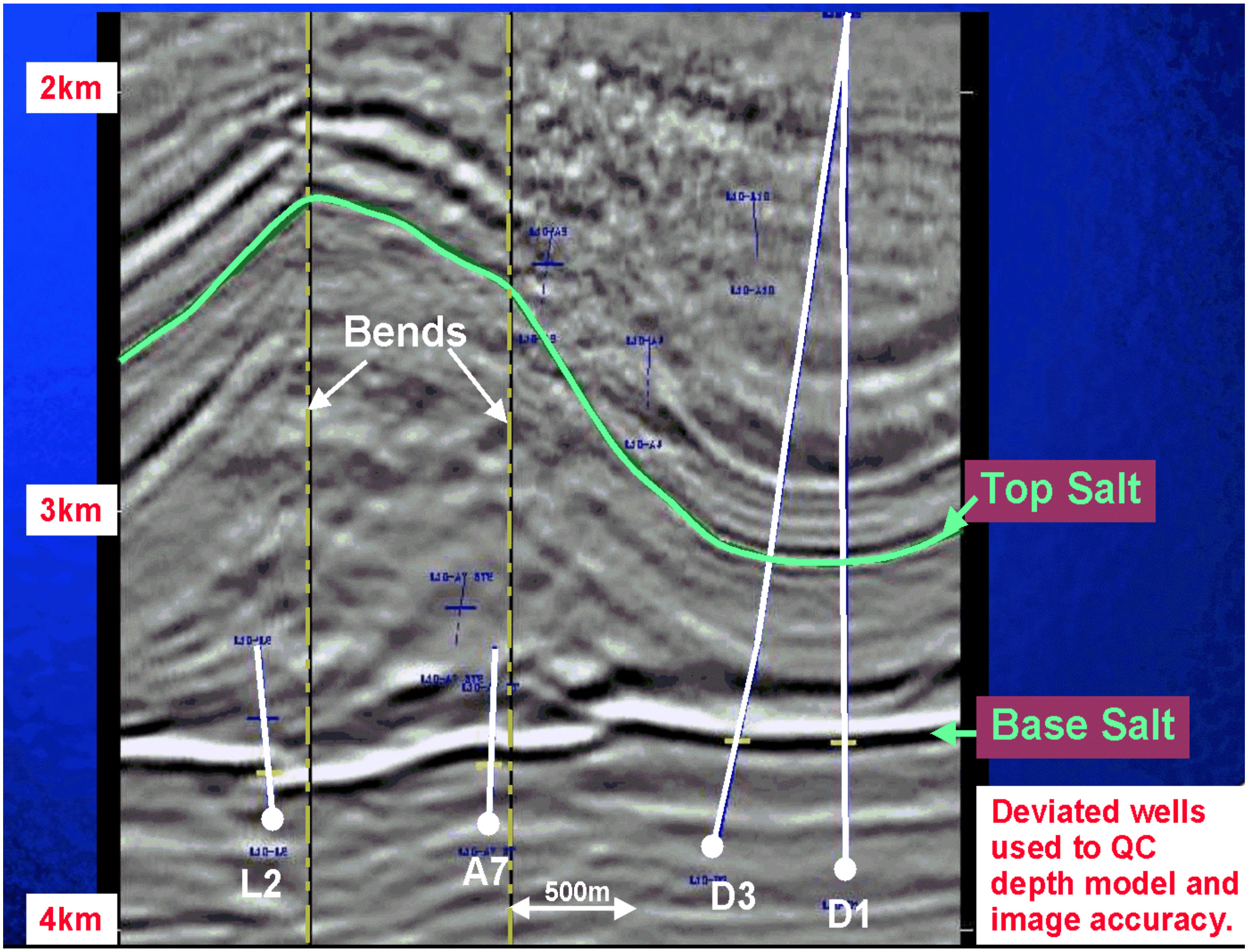

Figure 4: An anisotropic depth image from the Dutch sector of the North Sea is being quality controlled with well data, much of it deviated. The A7 well encountered hard dolomite immediately above the Base Salt that was faster than the constant velocity assumed for the Salt. This led to a depth error of 20m. The L2 well encountered a fault at Base Salt that is clearly imaged on the seismic data. This confirms that the errors in lateral positioning are also small.

Acknowledgements
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References

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