Comparison of seismic-based methods for fracture permeability prediction

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Abstract

There are several methods based on seismic reflection data for locating natural fracture systems and predicting their permeability. The only practical way to compare the predictive accuracy of each method is to evaluate the results from different oilfields using data from several wells in each field. We have studied methods based on reflection amplitude, reflection curvature and its derivatives, coherency cube, spectral decomposition, ant tracking technology, azimuthal anisotropy of P-wave velocity, and duplex wave migration (DWM) amplitude cube analysis. Here we report and analyse the results of each method for carbonate fracture plays. The study involved the analysis of several 3D data volumes from two different areas using results from hundreds of wells which have been drilled over the last three decades. We conclude that the DWM technique is the most reliable method for fracture permeability prediction. Lukoil planned a 2010 drilling programme for horizontal wells based on this DWM technology, and the first exploration results show that the locations of fracture systems were predicted with an accuracy of 25 m.

Introduction

The oil and gas industry has matured to the point that many conventional plays based on porosity have been exploited to the level of near depletion. Accordingly, the industry has shifted towards plays exhibiting porosity and permeability that are enhanced by natural fracturing. This trend has given rise to a dramatic increase in research into, and experimentation with, several methods for delineating the location of fracture systems and for predicting their associated permeability. To further complicate matters, after locating a highly permeable fracture system and drilling into it, we may obtain significant oil yields or we may find that the fracture system has a very high water cut. Therefore, the fracture prediction process is one that must be integrated with the knowledge of the reservoir gained during the exploitation process. The starting point is knowledge about the exact location of the fracture systems, then we attempt to characterize the permeability of the fractures, and this combination of information enables the engineer to design a precise and controlled exploitation plan for the field.

Methods based on seismic reflection data capable of detecting faults with small throws (e.g., coherency cube and reflection curvature) and methods capable of detecting micro-fracturing (e.g., azimuthal anisotropy) have been extensively developed and used in the industry for several years. These and other methods require calibration and verification by well data so that the most useful and reliable information can be extracted. For this process of calibration to be successful in the case of fracture detection, it is most important to choose the best parameter for calibration. In the same way that we have developed rigorous methods to calibrate TWT against formation tops, or to calibrate impedance to porosity, we must develop a formalized criterion for calibrating fracture prediction methods to the actual fractures as observed via the well data. In the case of TWT and impedance, we can measure depths and porosity directly from the well data. However, in the case of fracture systems within the reservoir, the information obtained from wells may be sparse, and in many cases wells have been drilled without using the necessary logging tools.

Some information can be obtained from outcrops and aerial or satellite imaging that can help us understand fracture systems. However, this information is very indirect when related to specific exploration targets: rock outcrops may be located hundreds of kilometres away from an area of interest, and the satellite imaging technology can only reflect integral information about the near surface sedimentary cover. Therefore, the wells are the only source of direct measurements related to the parameters that define the subsurface fracturing.

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How can well information be used to calibrate seismic-based fracture prediction?

Currently, there are three main types of well data that give information about fracturing: core sample analysis, logging, and test (production) data. For the purposes of oil and gas exploration we are most interested in open macro-fracture systems and this information is obtainable from these three types of well data. We now must consider the peculiarities of the determination of the parameters that can be measured from these sources of well data and the ability of each of them for seismic-based fracture prediction calibration.

Natural fracturing is a characteristic feature of most reservoirs. We need to distinguish between the three main types of fracturing, categorized by their relative size: micro-fracturing, meso-fracturing, and macro-fracturing. The lengths of micro-fractures are of the order of millimetres, their apertures are microns wide, and they can only be observed under the microscope. Meso-fractures have lengths of centimetres, apertures of the order of tens of microns, and they can be seen in core. The lengths of macro-fractures are measured in metres, their apertures are of the order of millimetres, and they split core samples into fragments. A complex of macro-fractures may form fluid-conducting corridors over lengths of tens to hundreds of metres with widths of metres to tens of metres. Macro-fracture systems can be identified and characterized by observing the results of pressure transient analysis (well tests).

Micro and meso-fracturing are revealed when we obtain access to core. The main indicator of the presence of the macro-fracturing that is so essential for productivity in carbonate reservoirs is the huge difference in flow rates between neighbouring wells. The full characterization of fractured reservoirs requires the use of expensive methods such as oriented cores, full waveform acoustic logs, image logs, and borehole scanners. The main parameters determined from such well logs and core samples are fracture direction and fracture intensity, but the determination of both of these parameters has multiple uncertainties. For instance, at least two fracture directions are usually detected because fractures generally form orthogonal systems. Moreover, two or three orthogonal systems have been observed on outcrops of the same layer.

The desired flow direction is that which corresponds to the open fractures. It is assumed that fracture direction may be derived from the full waveform sonic logs and image logs. Full waveform sonic logs do indeed allow the determination of anisotropy orientation within the layers. However, intervals of intense fracturing at the points of intersection with conducting corridors are usually characterized by extreme growth of the borehole diameter due to spalling of the crushed rocks, so the readings of downhole tools for such intervals are either absent or unreliable. A well log plot from such a zone is shown in Figure 1. Low values of gamma ray response together with high values on neutron logs show the rocks of this section are dense carbonates. The deep caving zone causes the loss of reliable full waveform sonic data over an interval of 2–3 m. This interval provides all of the production from the well according to production logging tool (PLT) data. The azimuth of anisotropy for the whole layer is determined as 60°, but this azimuth does not reflect the orientation of the conducting corridor and, therefore, cannot be used for seismic-based fracture prediction verification.

The detection of systems of open fractures is based more on PLT data than on the interpretation of image logs, which may be influenced by subjective factors. As shown in Figure 1, the spikes in the caliper log and sonic log, the steps in flow rate, and the weak signals on the full waveform sonic logs clearly identify an open fracture at 1928 m measured depth. Unfortunately, it is not possible to determine the fracture direction of this interval without the availability of oriented cores or reliable image logs.

Various parameters are used for quantitative evaluation of fracture intensity, for example, the number of fractures per section, area, or volume. Also we can use fracture spacing (the reciprocal of fracture intensity), total length of fractures, and the apertures of fractures. However, the use of such measurements taken from slices of core samples can only describe micro-fracturing and, less commonly, meso-fracturing. Macro-fracturing, which is important for exploitation and the target of the seismic prediction methods, cannot be measured by such simple techniques because either no core is recovered from intensely fractured intervals or only fragments of core are recovered. Consequently, to obtain information about open macro-fracture intensity we must measure a parameter directly related to the intensity of macro-fracturing. That is, we need to measure the intensity of the flow passing through the fractures. Unfortunately this flow rate cannot be measured directly, but it can be calculated based on bottom-hole pressure and flow rates.

There are several parameters based on flow rate and on well-head to bottom-hole pressure difference: hydraulic conductivity, productivity index, piezo-conductivity index, and permeability. The productivity index is the simplest as it is the ratio between flow rate and drawdown. It is the best criterion for the comparison of fracture intensity between wells against each other, if the fluid and reservoir are identical at the two wells. Flow rates of formation water and oil may vary dramatically due to differences in relative permeability and viscosity even with the same drawdown. Also, flow rate values may be distorted if test intervals include good porous or cavernous reservoirs near the fractured system.

Hydraulic conductivity may be calculated by the Dupuis equation which includes skin factor, borehole radius, and productivity index. Hydraulic conductivity could be a useful parameter for verification of seismic fracture prediction; however, it is frequently not available, whereas the productivity index is shown on all test reports. The permeability may be calculated from hydraulic conductivity, but

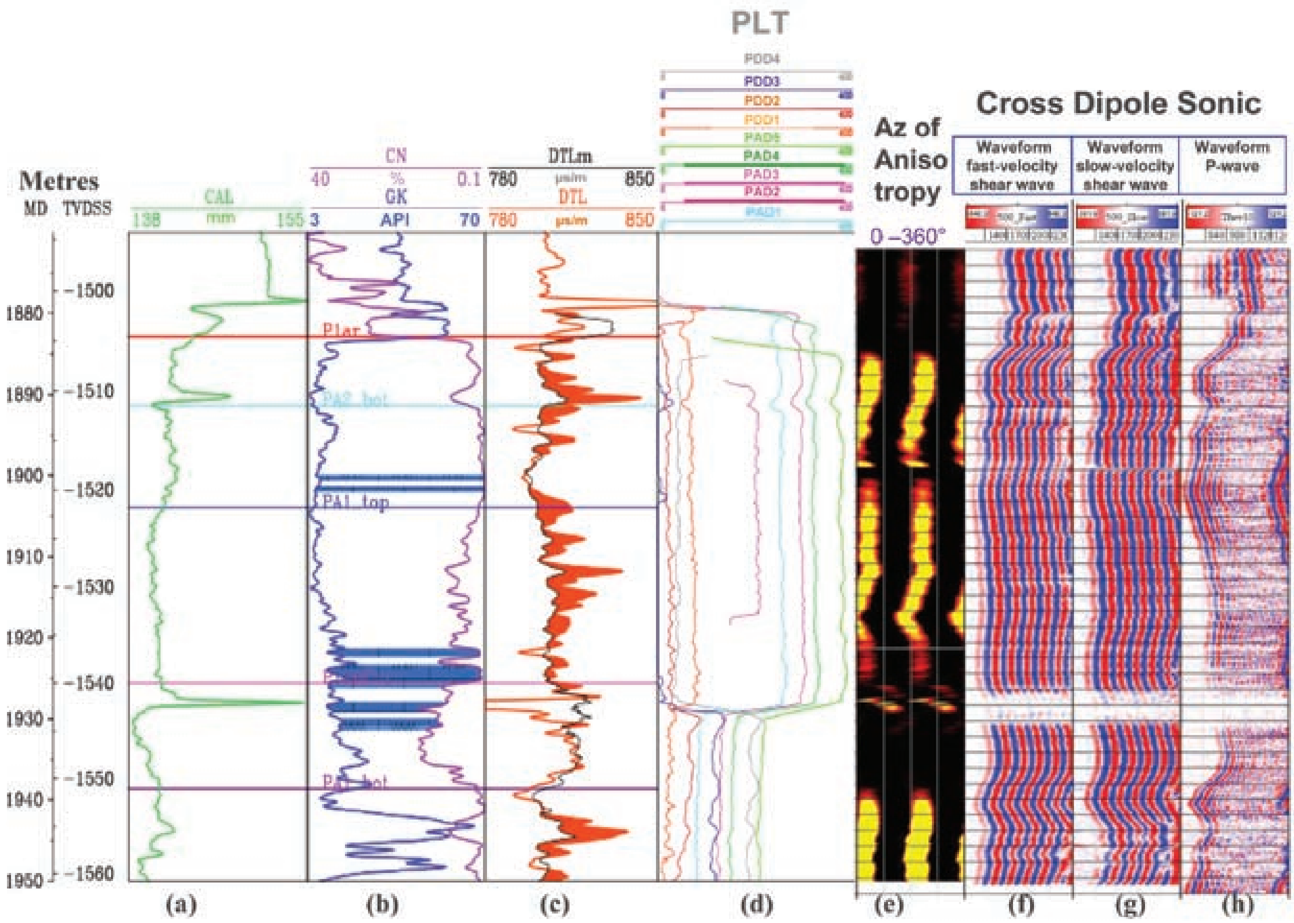

Figure 1 Well logs showing a fractured zone over the depth interval 1926–1928 m (measured depths). The display panels are as follows: (a) Caliper (mm). (b) Compensated neutron porosity (%) and natural gamma (API). Solid blue indicates fractures interpreted from resistivity log (not shown). (c) Stoneley wave travel time measured (DTL) and modelled from other logs (DTLm). The difference in solid orange is a permeability indicator. (d) Production logging tool responses for five runs in the borehole at different velocities. Flow rate is shown in arbitrary units for flow choke 16 mm in all cases: PDD runs are during descent, and PAD runs are during ascent. (e) Anisotropy in shear wave velocity: bright yellow indicates azimuth of fast direction for 10% anisotropy, and black indicates zero anisotropy. (f)-(h) Full waveform responses for cross-dipole sonic log for (f) fast shear wave, (g) slow shear wave, and (h) P-wave.

it is strongly influenced by error in the measured width of the vertical permeable conducting corridor, which can only be done accurately if the PLT data are available. The piezo-conductivity factor (rate of pressure change) may be successfully used for the detection of reservoir connectivity between two wells.

Hence, the results of pressure transient analysis, in spite of the high level of uncertainty, provide the most reliable information about fluid behaviour affected by anomalous macro-fracture systems in the reservoir. Moreover, well tests are more often available than other methods (full waveform sonic logs, image logs, and PLT). Therefore, we consider the well test results to be the best data for the calibration of seismic attributes used to predict fracturing.

Standard seismic-based methods for fracture prediction

Several standard methods were used to test the ability to predict fracture location and permeability. These included the following post-stack attributes:

- The analysis of horizons (Chopra and Marfurt, 2005), or so-called geometric attributes (dip angles, dip azimuth, reflection curvature, and their derivatives).
- Horizon amplitude analysis.
- Volumetric attributes such as coherency, dip angle, dip azimuth, curvature, and their derivatives.
- Decomposition of the wavefield into amplitude cubes for various frequency bands, which is commonly referred to as spectral decomposition.
- Ant tracking technology.

The technologies listed above are all in common use in the industry today, and so the methodology is not described here. However, the results of application of these techniques on two carbonate fracture case studies will be shown and discussed.

Azimuthal analysis of P-wave velocity and amplitude is commonly used on pre-stack seismic data for fracture detection and characterization (Rüger, 1998). Again, the methods are not described, but we will show the results

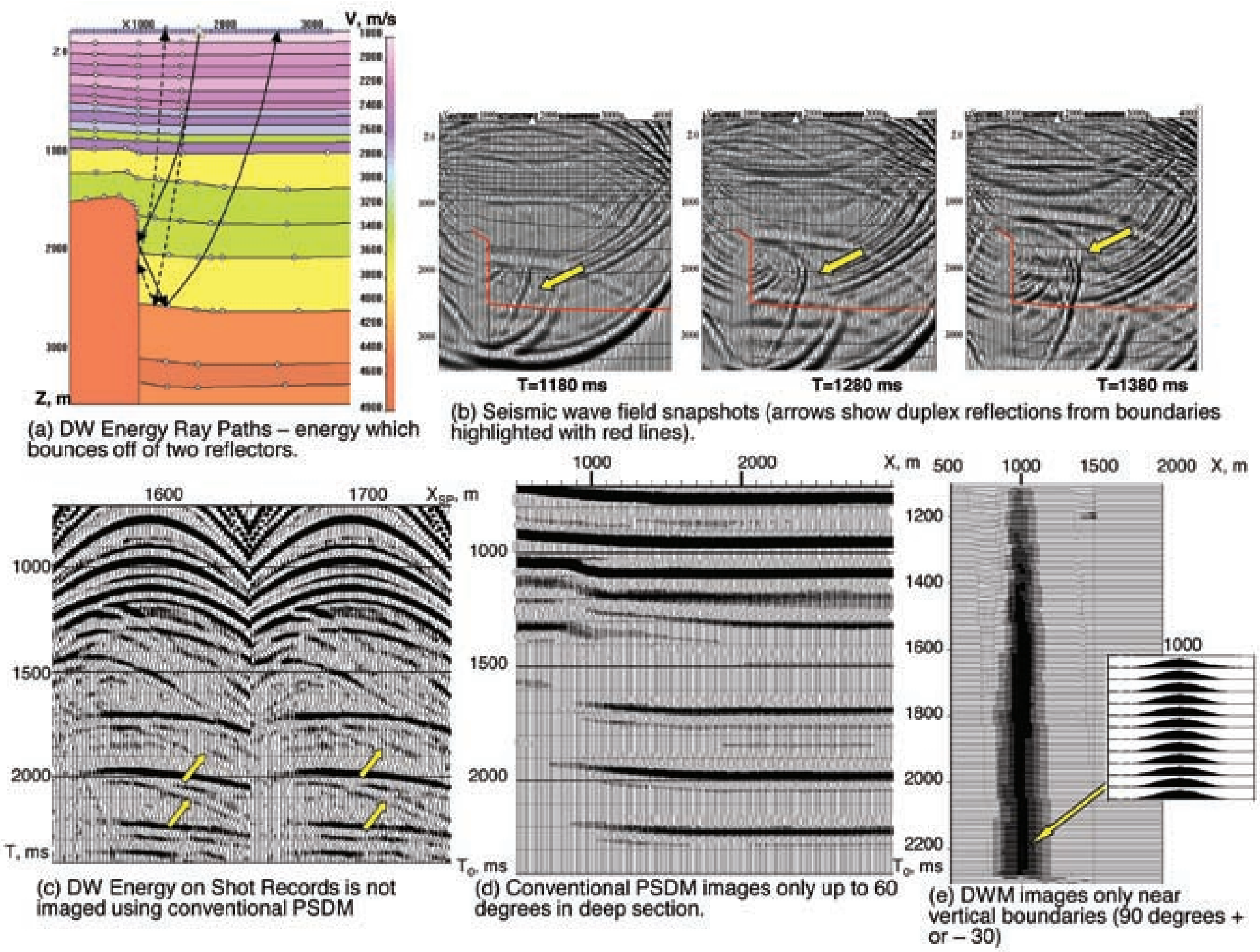

Figure 2 *Comparison of imaging capabilities of conventional PSDM versus DWM. (a) Duplex wave energy raypaths for energy which bounces off two reflectors. (b) Seismic wavefield snapshots (arrows show duplex reflections from boundaries highlighted with red lines). (c) Duplex wave energy on shot records is not imaged using conventional PSDM. (d) Conventional PSDM images only up to 60° in the deep section. (e) DWM images only near vertical boundaries (90° ± 30°).*

from the P wave azimuthal velocity study. Duplex wave migration (DWM) is also a pre-stack method, but a new type of 3D pre-stack depth migration that is not well known in the industry, so this technology is described in the next section.

Duplex wave migration

Figure 2 compares the information content in conventional pre-stack depth migration (PSDM) versus duplex wave migration (DWM) data cubes. Duplex wave energy is stacked out by conventional PSDM which assumes single-bounce kinematics. Similarly, single-bounce energy is stacked out by DWM because it images only energy that has undergone two bounces, one of which is a user-defined base boundary in depth.

DWM is a completely different method of pre-stack depth migration developed by the specialists at the Ukrainian State Institute of Geological Prospecting (Gornyak et al., 2008). It may be thought of as a conventional PSDM that has had its impulse response turned through 90°. DWM separates duplex wave energy from single-bounce energy and uses these wavefields to image vertical boundaries. By definition, duplex wave energy has undergone two reflections prior to returning to the surface, from the sub-horizontal surface (base boundary) and the targeted sub-vertical surface, in either order. Duplex reflections from vertical boundaries reach the surface, even when a small surface recording aperture has been used. Duplex wave energy is much less than primary energy, however, the kinematics of duplex and primary reflected wavefields are very different, thereby enabling DWM to separate them effectively (Marmalevskyi et al., 2006). Standard imaging methods treat duplex energy as noise and these wavefields are suppressed in conventional PSDM.

The properties of DWM are the inverse of the properties of conventional migration methods. PSDM is characterized by high vertical resolution but low horizontal resolution, whereas DWM has low vertical resolution and high horizontal resolution. The improved horizontal resolution of DWM is due to the fact that the Fresnel zone is now oriented in the vertical plane. It is also this characteristic of DWM that leads to its property of low vertical resolution. Consequently, we use the PSDM image to set the lower and upper boundaries of the reservoir, and we use the DWM amplitude cube to provide the detailed information about the vertical boundaries within the reservoir.

The low energy of duplex waves and the peculiarities of DWM cause its own class of noise. Foremost is the spatially variable energy contribution from the reflection from the base boundary. This type of noise appears as a low frequency background in the DWM amplitude cube and it is removed in a later post-processing phase (Khromova, 2008). 3D acquisition footprint noise sometimes has energy comparable with the vertical boundary image and it can be difficult to remove. However, efficient methods for the suppression of 3D footprint noise on DWM data cubes have been developed.

Can we use reverse time migration instead of DWM?

Reverse time migration (RTM) can image duplex wave energy and the imaging condition is reasonably stable in the case of a clean boundary, as is the case with salt domes. Farmer et al. (2006) presented the results of RTM applied to a 3D dataset to produce a cube of the vertical boundary images from a salt dome. In that case, the problem of the RTM hindrance waves was solved by using a reference velocity for the salt that was very different from the velocity adjacent to the salt dome. The essential characteristic necessary for this method to work is a significant difference in travel time for waves travelling inside the salt compared with their travel time in the sediments surrounding the salt. Faults and fractured zones in reservoir country rock usually have thickness in the order of one seismic wavelength. Defining a substantially different velocity to this narrow interval around the fractured zone will not produce a significantly different travel time for the purpose of attenuating the hindrance wave energy.

Comparison of several fracture detection methods

Case Study 1 – Oilfield N:

The reservoir of Oilfield N is in a complex of Lower Permian carbonate rocks with total thickness of 60–100 m and at depths in the range 1300–2000 m. Two wells, 700 m apart, located on the flanks of an elongated structure (Figure 3a) are characterized by extremely high productivity index (PI). The PI of well 2 is equal to 1800 m^3 d^{-1} MPa^{-1}, and the PI of well 17 is 1200 m^3 d^{-1} MPa^{-1}. The well interference test showed extremely high levels of conductivity between these two wells. The pressure response was registered after one hour and the conductivity index is equal to 12.7 m^2, which is comparable to the characteristics of an oil pipeline. Hence, it was concluded that wells 2 and 17 are communicating via a zone of open fractures.

Maps of different seismic attributes calculated in the pay zone on stacked seismic data as well as a duplex wave amplitude cube are shown in Figure 3b-f. The linear anomaly is registered on all of the maps. However, in the attributes calculated from PSDM stacks (Figure 3b-e) the anomaly is shifted 70–90 m southeast of well 2 and 150–200 m south of well 17 to envelope the two wells like a two-pronged horn. However, the linear anomaly on the DWM amplitude map (Figure 3f) suggests an intensely fractured zone that exactly coincides with these two wells, and this directly measured high amplitude anomaly agrees with the observations of high productivity and high conductivity.

Case Study 2 – Oilfield M:

The reservoir in Oilfield M is in a complex of Lower Devonian carbonate rocks with total thickness of 180–250 m at depths in the range 3700–4500 m. Abnormally high formation pressure had been recorded for the pay zone so the wells were drilled with heavy mud. Two wells of interest are located on the crest of the anticline (Figure 4a) and they are characterized by having the highest PI values for the whole field. The well interference test shows good fluid conductivity: the response to pressure change was registered at a distance of 2.5 km within 16 hours. Therefore, these two wells are definitely linked by a fluid-conductive open fracture system and this provides an excellent opportunity to compare the effectiveness of several methods for fracture permeability prediction.

Maps of different seismic attributes in the zone of interest around these two wells, calculated on both stacked volumes and by special pre-stack processing procedures, are shown in Figures 4b–f. All of the seismic attributes calculated on stacked data, except for the P-wave azimuthal velocity anisotropy attribute (Figure 4e), correctly determined the general direction of the fracture systems in this area, which matches both the azimuth connecting the two hydrodynamically linked wells and the anisotropy direction as determined by the full waveform sonic log in well 49 (Figure 4a). However, the exact match between the well locations and the delineation of the open fracture system connecting the two wells is identified only on the DWM amplitude map in Figure 4f. The attributes calculated from the stacked data are characterized by rough localization of linear anomalies and ambiguous interpretation caused by intense noise-like anomalies. Furthermore, the linear anomalies are not revealed at all by the azimuthal velocity anisotropy, and the distribution of the anisotropy parameters is almost inconsistent with the properties of rocks as determined by well data (e.g., there is no indication of the high conductivity between the two wells determined by the interference test).

Explanation of results

The analysis of the attribute maps computed on stacked data clearly indicates that the locations of the linear seismic

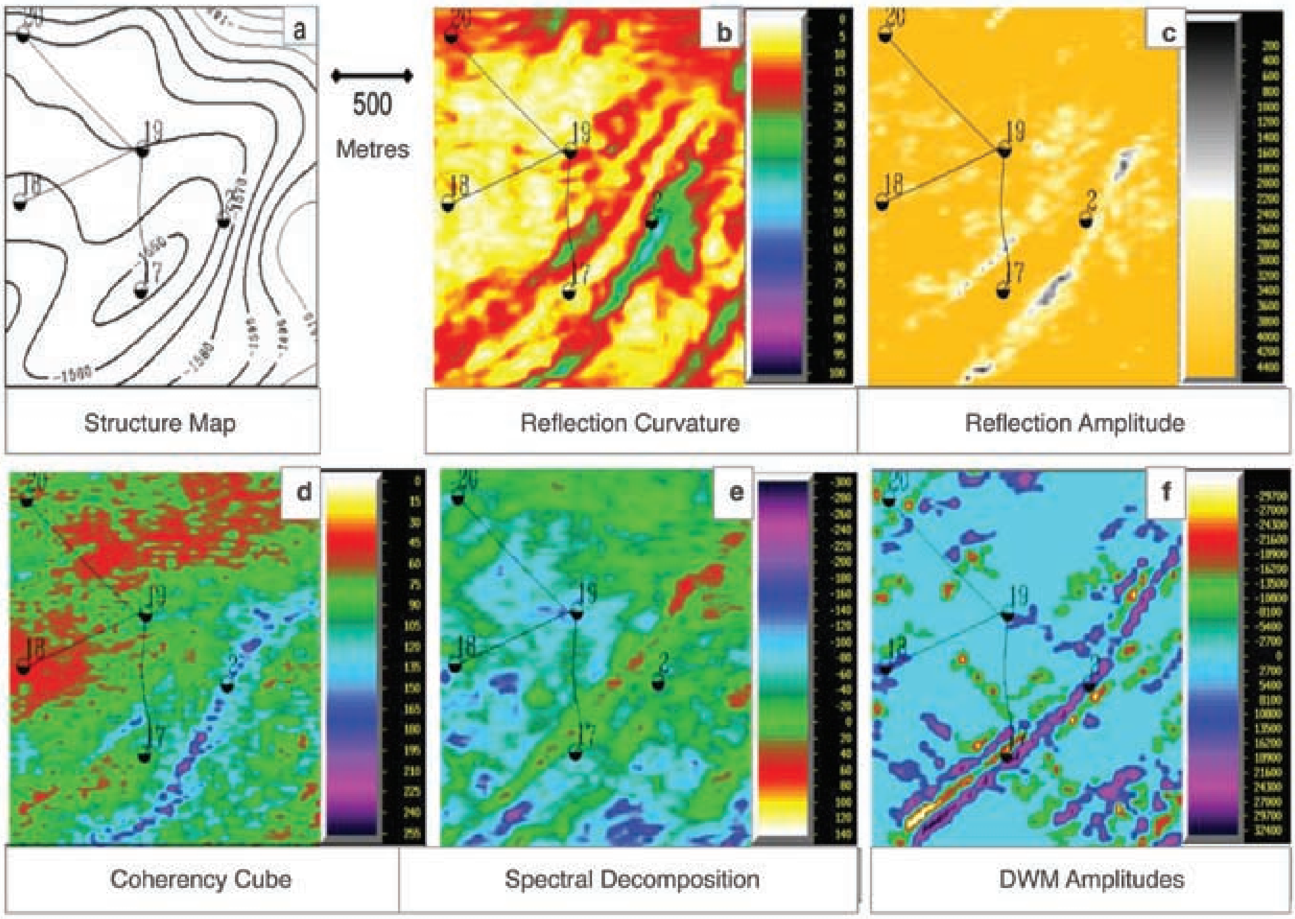

***Figure 3** Sections of different seismic attribute maps, each attempting to predict the location of tectonic macro-fracturing in an area which features two high production wells (2 and 17) in reservoir N.*

anomalies do not correspond with well production data and the results of interference tests. In the case of coherency and reflection curvature, and other geometric derivatives, we believe that the anomalous locations are highly influenced by the morphology of the bedding horizons themselves, rather than a direct observation of the actual open macro-fracture system. The coherency attribute does not detect the existence of the systems of open macro-fractures directly because there is no vertical throw associated with the fracture systems. The curvature attribute implies that fractures probably exist in the vicinity of the curved bedding; however, they do not directly indicate the exact location of those fracture systems. The spectral decomposition attribute can indicate changes in fracture systems; however, this attribute can be heavily contaminated by subtle changes in the bedding thickness which again is related to the specific bedding morphology. In other words, all of these methods have been proven to be unreliable in both of these oil reservoirs.

Due to peculiarities of the azimuthal velocity anisotropy method, the resulting map probably indicates the distribution of micro-fracturing complicated by changes in lithology. However, this type of fracturing is not related to the high levels of oil productivity in this reservoir (600 m^3 d^{-1}, and maximum reservoir porosity is 6 to 8 %). In fact, this map does not contain information about the known fluid-conducting fractured corridors and the drainage area linked to them. The map will not identify the locations of any potential by-passed fracture zones, which are essential information for reservoir engineers. In fairness to the method, it must be mentioned that the 3D recording was not designed to be wide azimuth for either of these reservoirs. Also, it is likely that if azimuthal amplitude analysis had been possible, this tool might have provided better information about the local zones of intense, open macro-fractures.

The best tie to well production and interference tests was provided by the interpretation of the DWM amplitudes cube. The ability of the method to accurately identify both the location and intensity of the open fracture systems can be explained in quite logical terms related to the features of this direct detection method.

The typical situation for DWM is that the target object is a sub-vertical boundary that is illuminated from both sides of the object. That is, shot points and receivers are located on both right and left sides of the vertical boundary.

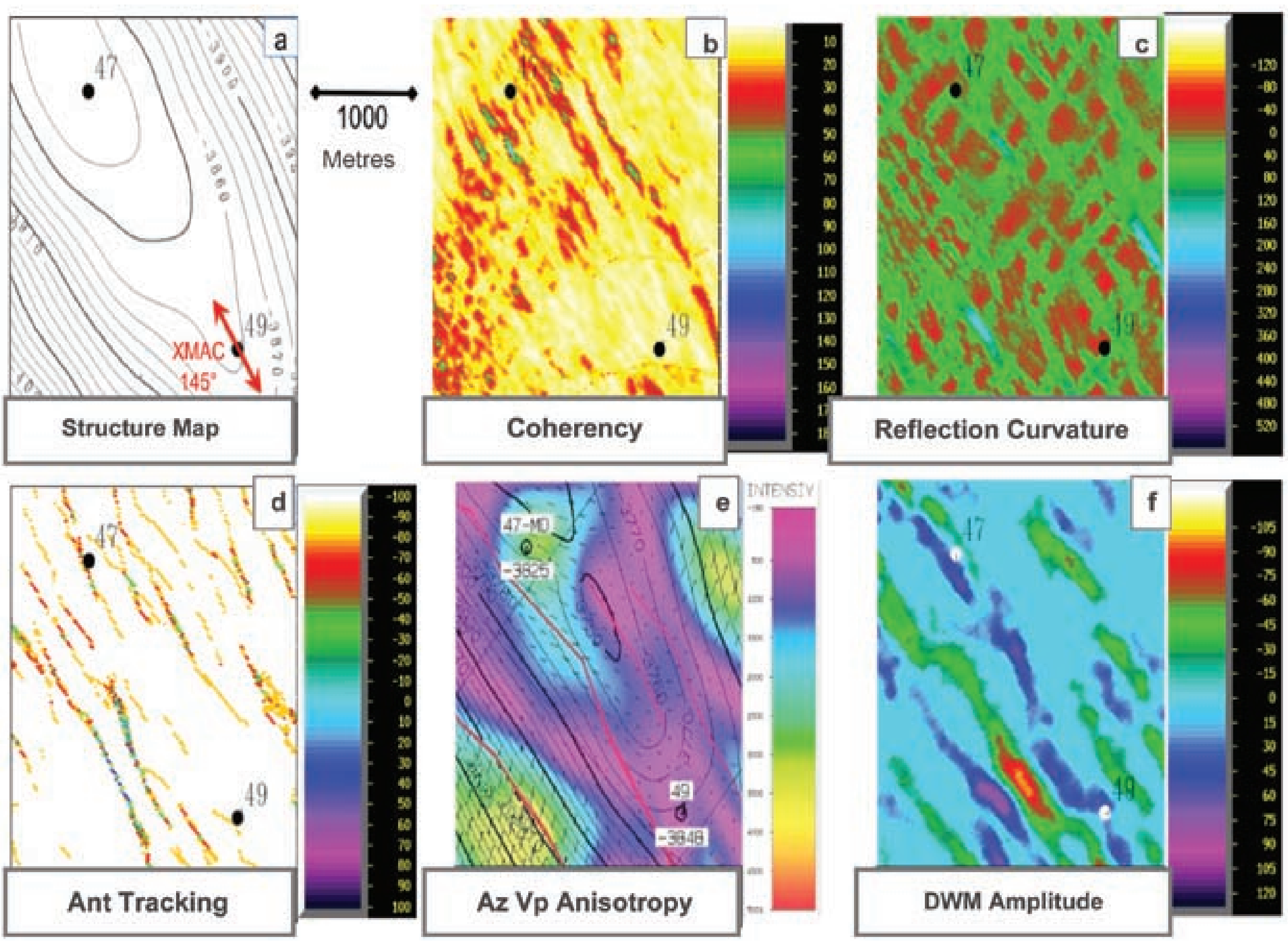

Figure 4 Sections of different seismic attribute maps each attempting to predict the location of tectonic macro-fracturing in an area which features two high production wells (47 and 49) in reservoir M.

Also, since we utilize a base boundary that acts effectively as a mirror under the vertical boundary, the sources and receivers are located both above and below the vertical boundary, depending on whether the signal strikes the base boundary first and the vertical boundary second, or vice versa. It is the kinematics related to these imaging schemes that provide the ability to accurately delineate the horizontal location of the vertical boundaries while using a small surface recording aperture. Conventional PSDM, on the other hand, suffers from the fact that the sources and receivers are located only on the surface.

The lateral positioning of the vertical boundaries using conventional migration is extremely sensitive to errors in the velocity model. The image of the boundary moves away from the source if the velocity is too high, and closer to the source if the velocity is too low. These errors are most critical if the target is a sub-vertical boundary. Such errors cannot be accurately detected using seismic data alone, and, it may also be challenging to do so even with the addition of information from several wells.

In the case of DWM we observe the same object independently from both sides, and if the velocity is in error the object will not be imaged clearly when these two images are combined. Hence this property of DWM provides an opportunity to make slight adjustments to the depth model that will dramatically increase the clarity of the image of the vertical boundary. Thus the DWM method has a built-in self-validation feature. Also, this property tends to limit the level of interpreter-generated error in the interpretation of velocity analysis tools. This dual imaging of vertical boundaries feature of DWM means that if the location of the vertical boundary is not correct, it is not possible for DWM to produce a well-focused image of that vertical boundary.

Early results from the 2010 Lukoil drilling programme

On the basis of the DWM analysis, Lukoil designed a drilling programme of multiple horizontal wells for 2010. The initial drilling results from the first well became available only in September 2010, so well productivity tests have not yet been finalized. This well was positioned to cross a set of fracture zones predicted by the DWM analysis, and the conclusions to date are based on the following types of observation: drilling speed, detection of intervals of loss of circulation, and broadband acoustics. The horizontal well has detected three zones of vertically oriented, intensive fracturing that are 5–8 m thick separated by two intervals of intact limestone country rock with widths of 40 m and 100 m. The spatial locations of the fracture systems predicted by the DWM analysis were accurate to within 25 m, which is the receiver interval used in the recording of the 3D seismic data.

Conclusions

Several methods for delineating and characterizing tectonic macro-fracturing have been compared by rigorous validation of the results using well logs, core samples, and well interference tests. Two reservoirs at significantly different depths were studied using several wells and various commonly used fracture prediction methods. The DWM technique provided the best results. For future work, we suggest that it is necessary to continue using this method to collect a statistically significant number of case histories so that the peculiarities, strengths, and weaknesses of the DWM method can be more fully understood. However, it is clear even now that the interpretation of DWM proved to be the most successful method for seismic-based prediction of permeable fracture zones in carbonate reservoirs with thickness of one or two wavelengths.

Acknowledgements

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