X-03   FAULT AND FRACTURE PREDICTION FROM COHERENCE DATA ANALYSIS, A CASE STUDY - THE MAGNUS FIELD, UKCS

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Abstract

It is well known that the coherence attribute computed from seismic data is a powerful tool for imaging discontinuities, including faults and fractures. Despite this, analysis of coherence data is rarely integrated in interpretation workflows. Interpreters continue to pick faults on reflectivity data and, at best, use coherence data to verify their work.

This paper presents a new approach to fault and fracture interpretation, FaultMagic®, which is based on the analysis of coherence and the integration of borehole data. It allows the interpreter to produce detailed and highly accurate fault and fracture maps using a data-driven approach. Interpreter bias is removed, and the speed and efficiency of mapping greatly increased.

A case study of the Magnus Field is presented in which this technique is used. The Magnus Field is in an advanced state of development with the lower reservoir, the Lower Kimmeridge Clay Formation (LKCF), being actively exploited. This low net:gross reservoir has a complexly distributed net sand volume that puts a premium on well locations and, in particular, producer-injector communication. Whilst the depositional model has contributed to the understanding of sandbody distribution, orientation and connectivity, it is essentially well based and cannot therefore address all the requirements of development well planning. This is particularly true as non-sedimentological factors almost certainly contribute to the reservoir's overall communication and its compartmentalisation. The LKCF in the Magnus Field therefore presented an ideal test for the FaultMagic® approach, whereby the entire inter-well volume could examined and the resulting fault information integrated with the well data, core sedimentology, UBI and core derived fracture information and RFT data.

The FaultMagic® process begins with flattening the coherence cube on a reference horizon and generating a set of horizon slices over the zone of interest. Each coherence slice is analysed in turn, with the interpreter digitising 2-point line segments or Ribbons® (Birrell and Courtier, 1997) to capture linear discontinuities (Figure 1). After 'unflattening' the interpretation using proprietary software FaultMagic®, the Ribbon® azimuths are computed. These are analysed on a rose diagram to identify dominant trends, and then colour-coded. Displayed in map view, the five main trends (two dominant and three minor) are clearly seen (Figure 2).

Displayed on vertical seismic data, it is apparent that many of the Ribbons® represent faults and fractures at a range of scales. Fault planes are picked where Ribbons® with the same trend

cluster together and are colour-coded using the same azimuth sets (Figure 3). This makes possible rapid and accurate fault mapping, with over 500 fault planes picked in 15 man-days (Figure 4). Lateral variations in fault and fracture density are evident from these maps and are clearly related to azimuth.

Independent of the seismic work, the fractures derived from borehole images from nine wells (one with core control) were also analysed. This work identifies fifteen sets of small-scale fractures (mm- to m- scale displacements) in all (Welch 1999), with fracture sets corresponding with all five of the fault trends identified by FaultMagic® (Figure 5); this indicates that these fault trends reflect pervasive structural fabrics. The remaining fracture sets are either localised features or regional features with shallow dips (less than 45°) not resolved by FaultMagic®. However, the restricted lateral distribution or shallow dip of these sets suggests that they are unlikely to contribute significantly to fluid flow between vertically isolated sandbodies.

These structural trends can be correlated with the field-scale fault systems identified by conventional seismic mapping. The north-western field-bounding fault corresponds with the blue Ribbon® trend and fracture set 6, while the Brent High faults are associated with the red Ribbon® trend and fracture sets 3 and 10. These fault systems are interpreted as tectonic in origin, formed during Mesozoic extension or Cenozoic inversion, but probably reflecting older (Caledonian and Tornquist) basement fabrics. In contrast, the shallow dipping fracture sets identified with the purple Ribbon® trend and fracture set 8 may represent syn-sedimentary slumping or gravity-driven sliding. This low-angle faulting is generally poorly imaged by FaultMagic®, since the coherence algorithm operates in the vertical domain. This is a limitation of the technique and while predominantly vertical faults are imaged, this does not disprove the existence of low-angle faults.

Unlike core or seismic analysis, borehole image analysis also differentiates between fractures that are open or closed in the subsurface (Figure 6) and shows that fracture aperture is a function of orientation with respect to the *in situ* stress field (Welch 1999). In particular, open fractures predominantly align NW-SE (fracture sets 12 and 13, corresponding to green Ribbons®), i.e. orthogonally to the regional minimum horizontal stress field while closed fractures align NE-SW (fracture set 6, corresponding to blue Ribbons®).

When integrated into the Magnus structural model, this combination of seismically-derived and well-based data provides a powerful tool for furthering our understanding of the subsurface complexity. In particular it provides valuable input to engineering model data and helps explain communication pathways between producer and injector wells and possible upward migration of hydrocarbons through thin sandbodies. It also provides useful insight into predicting structural complexity and net sand presence at future well locations. Although not a complete solution, it forces a re-examination of the existing geological and engineering models and in so doing has a real impact on oil production.

References

Birrell, S., Courtier, J. 1997. Advanced Structural Analysis of 3D Seismic Data, Using the Correlation Attribute. *1997 PGE Conference, Petroleum Geology of North West Europe, Barbicam 1997.*

Welch, M. 1999. The Use of Image Logs in Reservoir Characterisation: An Example from the Magnus Field Northern North Sea.
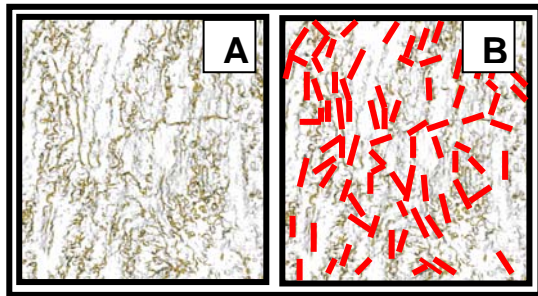
Figure1. Coherence horizon slices. Linear discontinuities seen on the uninterpreted slice (A) are digitised as 2-point line segments or Ribbons® (B).

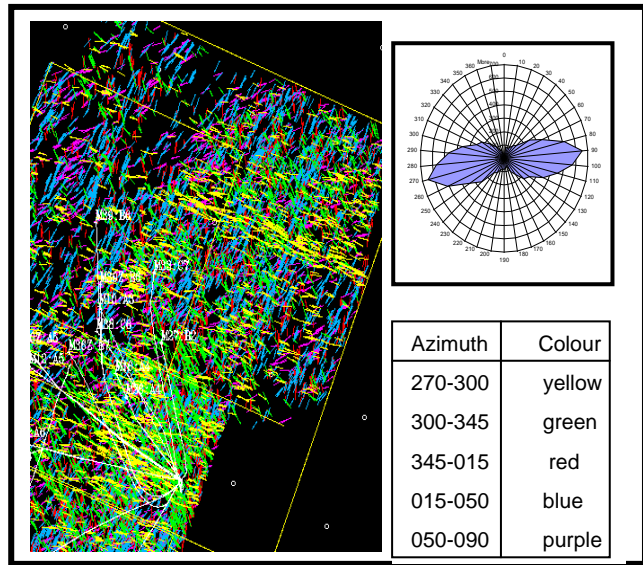| Azimuth	Colour
270-300	yellow
300-345	green
345-015	red
015-050	blue
050-090	purple

Figure 2. Ribbons® colour-coded by azimuth and displayed together for all horizon slices, with the dominant trends clearly seen (coloured green and blue). The Rose Diagram display may also be used to identify dominant trends.
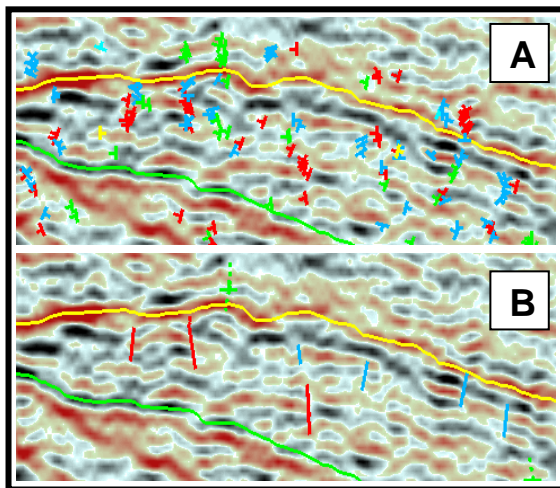

Figure 3. Ribbons® colour-coded by azimuth and displayed on vertical seismic data (A). Fault planes are picked where Ribbons® of each trend cluster together (B).
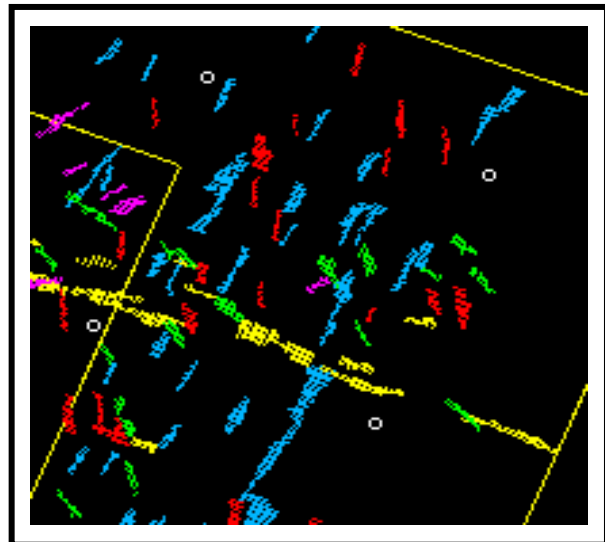

Figure 4. Fault planes displayed in map view. The efficiency of the technique resulted in 500 fault planes being picked in 15 man-days of the project start date. Fault terminations can clearly be seen.
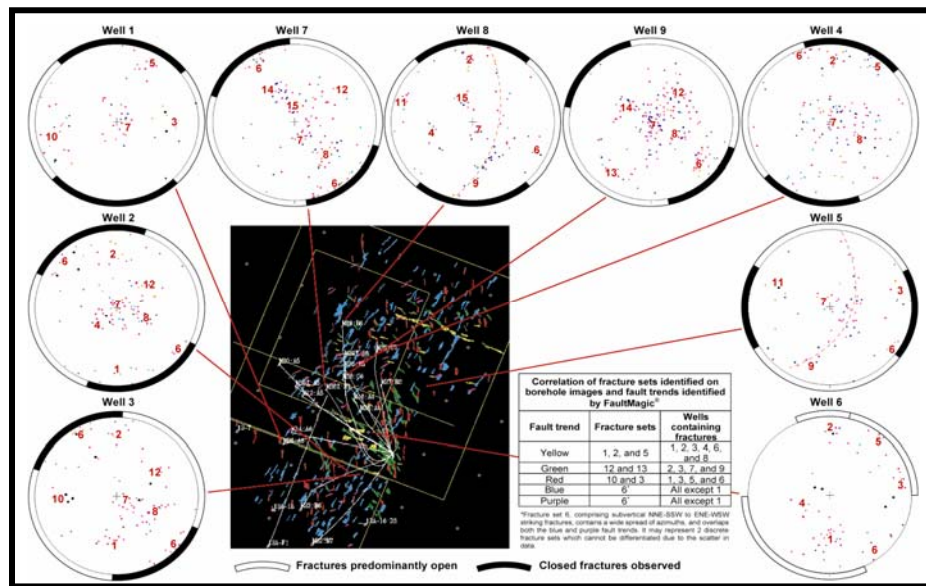
Figure 5. Analysis of fractures from borehole images from nine wells identified populations of small-scale fractures (mm to metre displacements) corresponding with all five of the fault trends identified by FaultMagic®.
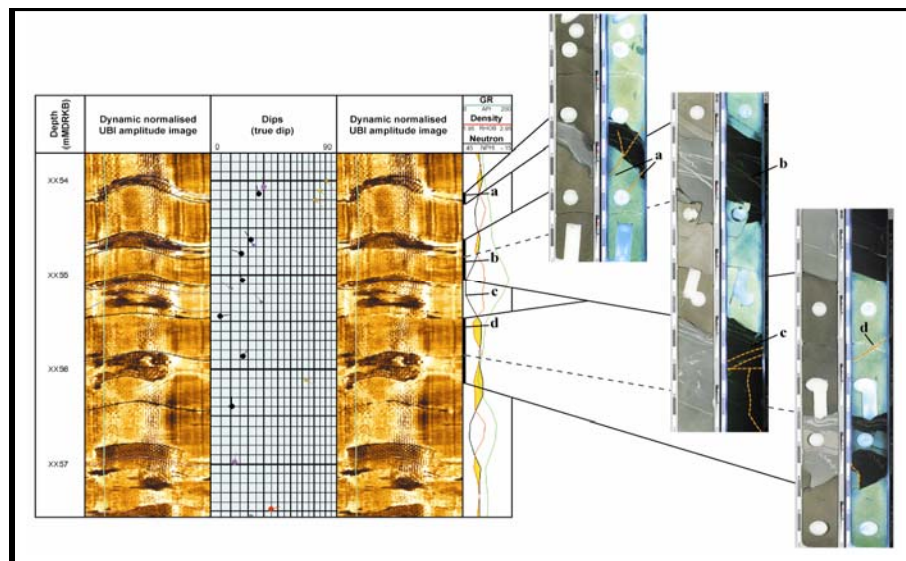

Figure 6. Borehole images also differentiate between fractures which are open and closed in the subsurface. This cannot be determined in core, since core is analysed under laboratory conditions and not under subsurface stress and fluid pressure. In particular note:

a) Fractures which are closed in the subsurface and in core (and identifiable on UBI images only by displacement of bed boundaries).

b) A fracture which is open in the subsurface (and resolved as a low amplitude feature on UBI images), but closed in core.

c) A dense network of fractures seen on core, which are too closely spaced to be resolved individually on UBI images. However, images do resolve low amplitude traces, suggesting these fractures are open in the subsurface.

d) A fracture logged as open on core, but not visible on UBI images, suggesting that it is closed in the subsurface.