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Natural Fracture Prediction for Discrete Fracture Modelling

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SUMMARY

There are many uncertainties in the modelling of discrete fracture networks; largely due to their intense spatial variation and a lack of direct integration between interpreted fracture data at the well level and seismic scale fault interpretations. The method described addresses these two major challenges and demonstrates how these inputs can be used to more accurately predict the orientation and density of fracture sets away from the well locations. Examples are taken from different fields to illustrate how computed fracture sets can be generated and verified against the well data using blind tests; and ultimately demonstrate how the method can improve well placement in fractured reservoirs.
Introduction

Characterisation of naturally fractured reservoirs is a challenge, with substantial modelling uncertainties increasing away from well locations. Significant heterogeneities in the data often mean that traditional fracture modelling approaches, which aim to predict orientations and densities, cannot fully delineate the characteristics of the fractures in a reservoir. This means that discrete fracture modelling can be a ‘black box’ when there is not enough data from the field to model the fractures accurately. As a result, fracture networks can often be oversimplified into sugar cube models that do not capture the intense variation in reservoir permeability (Salimi and Bruining, 2009). In this paper, we propose a new methodology that aims to geomechanically predict the fracture orientations and density in reservoirs (Maerten, L. et al, 2006) and therefore provide a more complete understanding of their impact on the reservoir.

A well-practiced and reasonably successful approach to characterising and modelling fractured reservoirs is using a combination of fracture predictors and detectors; for example, curvature (Chopra and Marfurt, 2007; Dengliang, 2013) and S wave or coherency (Chopra, 2002; Neves et al., 2004). The predictor attributes detect the location of a fault or fold, and from that we can sometimes assume that there are associated fractures, whereas a detector will be targeted to looking for open fracture corridors or swarms (Gabrielsen 1990; Questiaux et al., 2010). For this paper we looked at data from carbonate, basement and clastic fields; providing examples that demonstrate an advanced geomechanical predictor for the likely orientations and densities of fractures. These predictions can be used to significantly improve the accuracy of discrete fracture networks (DFNs), and ultimately well placement.

![Figure 1 Image (left) showing a traditional DFN model with little general orientation variation and no local variation. Image (right) with the new method showing the opposite. Stress rotations based on interpreted fault model and observed well fracture data help predict fracture orientations away from the wells.](image)

Methods

Rather than relying on locations of major structures as a proxy for fracture locations (such as curvature, Chopra and Marfurt, 2007; Dengliang, 2013) the new methodology amalgamates interpreted borehole fractures as ‘hard data’ with fault interpretation as the ‘near field’ stress model. These are used, along with a far field stress value, as inputs for forward modelling simulation (Maerten, F., 2010). The result is a calculated stress field for the reservoir that enables the generation of computed fracture sets. These are then populated into the model area using the detailed localised stress property. This stress orientation prediction enables the improved placement of fractures within a DFN.
Model simulations capture the first-order relationship between fault geometry, fault displacement distributions, and perturbed stress fields to place discrete fractures.

Existing DFN methodologies have two main limitations that are significantly mitigated using the new methodology:

1. A good existing understanding of how the fracture sets should be subdivided: Data analysis and identification of fracture sets is beneficial to the new process, but is not essential and forward modelling can be run without it. This simulation calculates the likely fracture orientations and associated tectonic regime based on a fit concept.

2. Little observed variation in the orientation of the fracture sets: Population of fracture orientations and densities in a traditional DFN is limited to certain attributes, such as distance to fault; or certain population distributions (e.g., log normal). These provide sufficient data only for rough statistical representations. The new approach introduces prediction of variation in fracture orientation and density away from the well locations as opposed to simple property propagation across the entire grid.

As the use of this new method is both borehole and seismic (interpreted from) centric, it makes sense to test its accuracy through the use of blind tests, omitting certain boreholes from the simulations. If the predictions are correct in these locations that can be validated, then theoretically with the support of other interpretations, this method can be used directly for well placement.

To test this approach, a low porosity sandstone gas field was modelled (Fig.3). The results show the overall trends and can be split into two separate sets of fractures:

- NW-Open: sub-parallel to a set of shear zones that are largely not visible in the seismic.
- NNE-Closed: sub-parallel to the major faults picked from the seismic.

There is significant stress orientation rotation in the south around areas of high shear-zone density (Fig. 4). The shear zones were incorporated into the fault model as physical planes. This fault model corresponds to the full field image on the right in Figure 4.
The blind tests involved using the approach on the three wells with fractures closest to the NW and NE orientations. This was to determine whether differing orientations observed in the remaining four wells could be predicted by the forward modeling simulation. The observed well fracture data indicated a significant stress rotation around these wells due to their proximity to areas of intense faulting—this is usually close to an area where the shear zones and NE trending faults intercepted each other. The simulation results show that these localised rotations were predicted by the forward modelling.

Figure 4 Image showing yellow stress vector lines (predicted) that will represent the orientation of the final fracture planes in the DFN. Also shown are the measured fracture data (discs) from the wells that were not used. The overall NW trend is seen in the vectors and the wells, meaning that they were correctly predicted. More importantly the vectors predict the local rotation from the faults (Fig. 3) that is also observed in the fracture data from the blind wells. The fault model has been removed from the left image for visualisation.

This local fracture variation was apparent in all directions (X, Y, and Z). As the borehole data was used directly, it was possible to represent the mechanical layering of the field. This was particularly apparent in the carbonate and clastic data sets, but more of a challenge in the basement reservoir. Both poor seismic imaging of the faults and little information on any segregation of the granite meant that modelled vertical fracture variation was difficult to propagate across the entire field. After building a fault model of more typical orientation for the setting, it was possible to break the fracture sets down into multiple tectonic events, which in turn could be modelled as separate discrete fracture networks.
Figure 5 Stress maps from the basement data set. These indicate that the different fracture sets within the field can be associated to separate tectonic events.

Left image represents a parallel joint set tied to normal regime with a SHMax of 49°.
Right represents a set of cross cutting joints that correspond to a reverse regime with a SHMax of 142°.

Conclusions

- Existing DFN methodologies are often simplistic and based on largely statistical fracture populations rather than directly on well data.
- This new method incorporates all data directly and enables the capture of local stress variations and represents their effect on discrete fractures.
- We have worked on basement, carbonate, and clastic environments to demonstrate the versatility of the process.
- Blind tests show that the method can accurately predict local stress rotations away from the well locations.
- When calibrated to data in a particular field, the simulations can be ultimately used for better well placement.

References