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Analysis of fracture networks in a reservoir dolomite by 3D micro-imaging

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Narrow fractures in reservoir rocks can be of great importance when determining the hydrocarbon potential of such a reservoir. Such fractures can contribute significantly to - or even be dominant for - the porosity and permeability characteristics of such rocks. Investigating these narrow fractures is therefore important, but not always trivial. Standard laboratory measurements on sample plugs from a reservoir are not always suitable for fractured rocks. Thin section analysis can provide very important information, but mostly only in 2D. Also other sources of information have major drawbacks, such as FMI (Formation Micro-Imager) during coring (insufficient resolution) and hand specimen analysis (no internal information).

3D imaging of reservoir rock samples is a good alternative and extension to the methods mentioned above. The 3D information is in our case obtained by X-ray Micro-Computed Tomography (μCT) imaging. Our used samples are 2 and 3 cm diameter plugs of a narrowly fractured (apertures generally <200 μm) reservoir dolomite (Hauptdolomit formation) from below the Vienna Basin, Austria. μCT has the large advantage of being non-destructive to the samples, and with the chosen sample sizes and settings, the sample rocks and fractures can be imaged with sufficient quality at sufficient resolution. After imaging, the fracture networks need to be extracted (segmented) from the background. Unfortunately, available segmentation approaches in the literature do not provide satisfactory results on such narrow fractures. We therefore developed the multiscale Hessian fracture filter, with which we are able to extract the fracture networks from the datasets in a better way. The largest advantages of this technique are that it is inherently 3D, runs on desktop computers with limited resources, and is implemented in public domain software (ImageJ / FIJI).

The results from the multiscale Hessian fracture filtering approach serve as input for porosity determination. Also the fracture apertures can be defined. One can use an adaptation to the filtering technique to determine the orientation of the extracted fractures in a sample as well. All these analyses contribute to comprehensive information on the fracture network in a sample. This processed data can then serve as input for permeability modelling.

All results from the μCT imaging and data analyses are combined and cross-calibrated with information from different techniques, obtained on the same samples. We apply for example the aforementioned laboratory methods (including permeability determination under increasing confining pressure) and 2D thin section analysis. Furthermore, we use 3D Focussed Ion Beam - Scanning Electron Microscopy (FIB-SEM) tomography to obtain 3D information at a much smaller scale. Eventually, we try to obtain an as complete as possible set of information for every sample analysed. The combination of the various techniques shows that especially the 3D imaging is important, as even on the small sample sizes, large differences between the present fracture networks can be observed. This starts to make it possible to explain the reasons for found differences between various wells. This research thereby hopefully leads to a better understanding of the (microscale) characteristics of a reservoir system.