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Multi-scale Fracture Network Characteristics in a Carbonate Reservoir Outcrop Analogue: Insights from μCT data in Core Plugs and Thin Sections.

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Motivation-Objectives

Most carbonate fractured reservoirs show high variation in lithology, diagenesis, fracture intensity, orientation and connectivity. This high degree of heterogeneity can have a significant impact on reservoir quality and sustainability of production. Outcrop analogues are key elements in the understanding of reservoir architecture and heterogeneity (Jones et al., 2015). Subsurface data represent an extremely small fraction of the reservoir complexity, while most times are not being representative for full fracture networks. This fact often leads to misinterpretation of well data and poor reservoir modelling. Outcrop analogue studies can significantly improve the understanding of fracture characteristics and their impact on fluid flow in hydrocarbon reservoirs. Capturing fracture data across multiple scales requires a range of different methods and appropriate technologies (Jones et al., 2015). We applied this strategy combining traditional fieldwork and digital data capture in a pilot study at a key outcrop along the Cretaceous Wasia and Thamama Group contact, in Ras Al-Khaimah (UAE), since these are regionally important fractured reservoirs.

Methods

Modern methods of digital acquisition, including terrestrial LiDAR or photogrammetry, are particularly adept at capturing detailed geometrical and geospatial attributes over wide areas. Their main advantage is that they result in more robust datasets over a larger scale-range, particularly for fracture heights, lengths, spacing, clustering, termination and connectivity. The acquired 3D point cloud data were used to extract a very detailed fracture network from the studied outcrop, including fracture orientations and 1D fracture density along two ~ 180 m long scanlines.

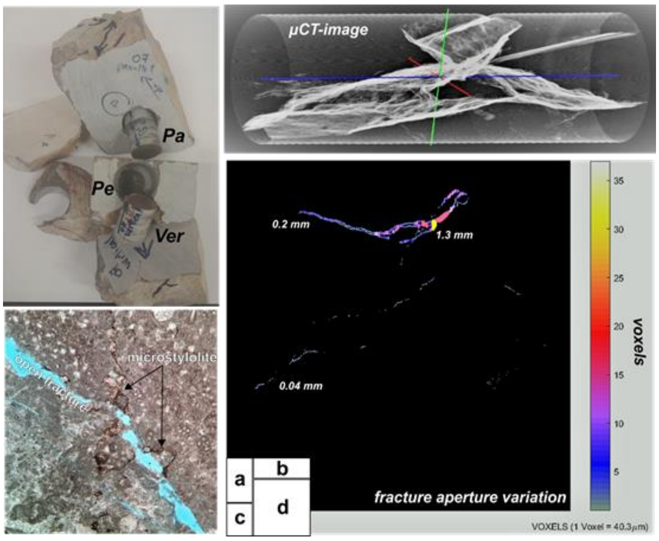

Figure 1a. Lab image showing the three-orthogonal plug-size cores drilled from the rock samples collected from the outcrop. b) High resolution micro-CT image from the examined core plugs, showing the detailed geometry of the microfractures and their overlapping setting. c) Microscopic image showing a mud-dominated packstone with an open fracture offsetting a brown-black colored microstylolite. d) Aperture variation along a fracture calculated from a 2D μCT image.

Additionally, large rock samples were collected along these two scanlines and plug-sized samples were drilled along three orientations orthogonal to each other, with one plug normal to the bedding and two along the bedding and orthogonal to each other (Fig. 1a). The core-plugs were analyzed with the technique of 3D X-Ray Computed Micro-Tomography (μCT). This is a non-destructive technique that allows to acquire images of the interior of the sample, in high resolution and high contrast, allowing to elaborate a 3D reconstruction (Fig. 1b). As in a tomography, numerous sections (e.g. 2000-4200) of the sample are captured in 2D to reconstruct with precision and detail the object in 3D. Moreover, thin sections were made from selected plug samples providing 2D information with a much higher detail in order to examine the microfractures distribution, aperture and filling.

μCT data scan details and processing

Standard samples (1.5΄diameter x 3΄length) were drilled from the outcrop rock samples. The plug-size samples were scanned using Xradia-520 Versa equipment from Zeiss, available with a maximum 160 kV high-energy and micro-focused X-ray tube. The device is equipped with a 2048 x 2048 pixels, noise suppressed, charge coupled detector assembly, having an innovative dual-stage system for getting high contrast images. For all samples, projections between

2651 and 4601 were taken. The distance of source and detector from the sample was chosen to be 73 mm and 50 mm respectively. This resulted in a pixel size (or voxel) of 40.39 microns. After scanning, the data were reconstructed (i.e. create a 3D image using all the 2D radiogram projections) using devices´ included reconstruction software.

The plug-size samples obtained from the outcrops had very low porosity, ranging from 0.21 to 3.65%, except for 2 samples that displayed porosity of 7%. Hence, it can be concluded that the fracture porosity plays a major role in these tight carbonates and this was one of the aims of this study. In order to obtain features from the 2D images we chose to apply a simple binary segmentation, by recording the range of pixel intensity values that represent the fractures in all slices of the sample. In order to better visualize the fractures in the 2D slice, a MATLAB code was written to segment the pixel intensity values that represent the fractures and assign those pixels white coloring, while the remaining pixels of the matrix in the slice are given a black color. All the segmented slices were loaded in the Vol-View software (open software), to visualize the segmented slices in 3D. This 3D view showed in great detail the fracture network distribution inside the samples (Fig. 1b).

Core-plug thin sections descriptions

Microscopic petrographic analysis showed that most of the rock samples can be classified as mud or grain dominated packstones with forams, echinoderms, bivalve fragments and sporadically Lithocodium-Bacinella green algae. Microstylolites and wispy seams are common, while most of the hairline fractures are straight and have several tip to tip overlapping segments filled often with calcite cement. Few fractures are open or partially filled with silt. Characteristic is that some younger open fractures cross-cut the earlier microstylolitic surfaces (Fig. 1c), while others are developed parallel to the stylolites.

Aperture Width Calculations

The aperture width clearly varies along the fractures (Fig. 1d), implying that is meaningless to assign a single aperture value for fractures in reservoir models. Therefore, an aperture width distribution over the 2D slice or along the full sample would be ideal. In this study, we calculated aperture width by measuring the distance normal to the fracture walls; i.e. by measuring the number of pixels lying between the two fracture walls. The full slice aperture distribution is displayed with a color scale in figure 1d and by multiplying the aperture distribution with the micro-CT scan resolution, we can obtain the fracture aperture in μm or mm. In the example of Fig. 1d, representing one of our most fractured samples, the fracture aperture ranges from 0.2-0.6 mm, with a maximum value of around 1.2 mm often located in the overlap zone or relay zone formed between the individual segments.

3D Fracture Intensity

Estimating the 3D volumetric fracture intensity (P_{32}) is a quite challenging task and most often is estimated indirectly from the 1D P_{10} or 2D P_{21} fracture intensity (Wang, 2005). The 3D fracture intensity (P_{32}) can be expressed as the area of fracture per unit volume of rock mass:

fracture density (m^{-1}) = fracture surface area (m^2) / sample volume (m^3) (Singhal and Gupta, 2010)

The fracture surface area is determined by counting the voxels in the complex fracture network in all slices of the sample and multiplying it with the pixel size to get the surface area of the fracture (m^2). This surface area is divided by the sample volume (m^3) to obtain the fracture density of the sample (units in m^{-1}). The fracture intensities P_{32} calculated from various scales and resolutions ranges from 0.75-3 m^{-1} with laser scanning ($P_{10} \rightarrow P_{32}$), 9-20 m^{-1} from field measurements ($P_{10} \rightarrow P_{32}$) to 12-35 m^{-1} (actual average P_{32} values from μCT data). It is important to note that the P_{32} fracture intensity obtained by μCT is expected to be much higher than the calculated values from other techniques, since this method is highly sensitive to distinct fracture orientation and size distribution, as well as due to the higher level of detail available in the μCT scan. This is also the underlying reason why it represents a true intensity indicator in the context of DFN modelling.

Conclusions

Application of this integrated microstructural methodology in a pilot field outcrop reservoir analogue provides a mean to gain high resolution data, forming a key input in reservoir geo-modelling workflows. The produced digital 3-D analogue, from the outcrop scale down to the core plug and thin section scale, provides essential data for the spatial representation of the reservoir heterogeneities, illustrating the complexity of fractured-carbonate reservoirs. Fracture parameters being quantified across a wide range of scales, and combined with elastic mechanical properties of the carbonate layers represent an ideal basis for the calibration of multi-scale fractured reservoir models.

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