Introduction
The Zarat field, located about 80km offshore Tunisia in the Gulf of Gabes (Figure-1), is a large gas condensate field underlaid by a thin oil rim, producing from fractured limestone reservoir of the ypresian Nummulitic El Gueria formation (Moody R.T.J. & Grant G.G., 1989 and Loucks & al.,1996). The development plan of the Zarat field was prepared through a simulation study, based on a 3D static matrix model combined to a fracture model representing the fracture network in the reservoir. The main objective of the fracture modeling is the assessment of the permeability distribution to allow the simulation of the well production, the flow behavior and the prediction of the early water and or the gas breakthrough.

Among several uncertainties studied in the plan of development, the fracture intensity of the reservoir represents the major uncertainty. In fact, the presence of fractures in the El Gueria limestone is proved in analogue fields to have a strong influence on the dynamic behavior of the reservoir fluids and deliverability of wells during production.

Although the limited data available in the field, a fracture characterization study was conducted based on the available core data and Oil Base Mud Images (OBMI), in order to build a representative Discrete Fracture Networks (DFN) model. This model will be used for the fracture network prediction, the assessment of the fracture porosity and permeability distribution that have to be used on the simulation study.

Fracture Characterization
The fracture characterization was based on the cores description of two first wells Zarat-1 (ZRT-1, about 150 m of core) and Zarat-2 (ZRT-2, 50 m of cores). Moreover, porosity and permeability mesurements from plug were also available for these two wells. The reservoir behavior is deduced from the core data (core images and thin sections) where the presence of porosity and permeability both in open fracture (Figure-2a) and in matrix (Figure-2b) were proved.

The OBMI Images and their fracture interpretation, available in Zarat North-1 well (ZRTN-1), were used to define the main fracture sets present in the reservoir.

Based on the core fracture description as the length, the inclination and the aperture, the fractures were grouped into categories of open fractures, partially open fractures, cemented fractures and tension gashes. The open fractures and its corresponding data set were the considered category for the fracture modeling; and it was directly used for the creation of the fracture intensity vertical distribution for the three wells. Two types of open fractures were recognized from core description: the small fractures and the long fractures having a height of more than 3 m. These fracture intensity logs of wells are the main well input for the fracture modeling.

In this study the fracture intensity is defined as number of open fracture per meter (Mauldon, M. & Dershowitz, W. 2000).

The well data analysis shows an inverse relationship between the matrix porosity and the fracture density (Figure-2c). In other hand the long fractures were assumed to be related to the fault intercepted by the well above the top of the reservoir (Chen-Chang, L. & al. 2010).

Thus the fracture intensity represents fractures related to the faults and fractures related to the background (fracture related to the matrix porosity).
Fracture Modelling
The Zarat field fracture model was built based on the DFN modeling concept by defining a number of fracture sets (each with its specific parameters) that were populated in the original 3D grid in order to estimate their porosity and permeability impacts.

Two 3D seismic attributes were used for the grid population of the well fracture intensity: the ant-tracking attribute for the Fault related fracture and the Acoustic Impedance attribute for the back-ground related fractures. The fracture intensity cube (Figure-3c) is the merging result of the fracture intensity related to the faults (Figure-3a) and the fracture intensity related to the background (Figure-3b). Assuming that most of the fracture are usually related to fault, a coefficient of 80% was assigned to the fracture intensity fault related and 20% to the background related.
Based on the azimuth, three sets of fracture were deduced from the OBMI image interpretation with the orientation respectively N160°, N35° and N90°, and with a mean dip of 70° (normal fault).

The fracture parameters such as size, shape, and orientation were assigned to each fracture set based on direct measurement either from cores, from OBMI or from outcrop analogues.

Several sensitivity runs were performed to assess the most appropriate fracture parameters. From outcrop and well data, the fracture length is variable from centimeter to more than ten meters. Therefore, fracture length was modeled in Zarat field being between 1m to 10m.

The Fracture Aperture was, after sensitivity process considering the core description and the results of the DST’s on wells, deduced as constant value of 0.2 mm.

The fracture porosity, fracture permeability and sigma were deduced from this fracture modeling process and were upscaled to be used, as complementary input to the 3D static model, for the reservoir dynamic studies.

The adopted DFN modeling workflow for the creation of the 3D fracture model included all the above mentioned steps and parameters is summarized in Figure 4.

**Figure 4 Fracture modelling workflow**

**Fracture Modelling results**

The main result is a 3D model including the fracture parameters that should be used on the simulation study to predict the flowing behavior of the planned wells of the field development plan mainly concerning the early water or gas breakthrough.

The fracture parameters considered are the porosity, permeability and the Sigma fracture. The fracture porosity was calculated as a function of the fracture intensity and aperture. The resulted average fracture porosity of the current DFN model is around 0.01% (Figure 5a).

The fracture permeability calculation used a cubic function relating the aperture and fracture intensity. The resulting permeability was compared to the real test results of Zarat-1 and then deduced for the three directions (I, J and K). The average fracture permeability calculated in the current DFN model is around 350md (Figure 5b).
The sigma factor is calculated using a function relating the fracture intensity and fracture spacing along the considered axis. The average calculated sigma factor is around 4 m$^{-2}$ (Figure 5c).

![Fracture modelling results](image)

**Figure 5** Fracture modelling results

**Conclusions**

The DFN was modeled based on seismic and well data (core and Image). Four sets of fracture were modeled: N160°, N35°, N90° and the picked fault network. The fracture sets were populated in the grid based on the matrix porosity for the background related fractures and following the distance to Faults for the fault related fractures.

The estimated average fracture porosity seems too small (0.01%) and it has minor effect on the total hydrocarbon volumes. However the average fracture permeability calibrated with test results is around 350 md and the average Sigma value is around 4 m$^{-2}$.

Although several approaches were used for the fracture modelling, the limited number and the quality of some available data are source of uncertainties.

Additional input data such as the results of new wells, analogues outcroup inputs such fracture length, fracture aperture and fracture intensity around fault systems using, by direct measurements or remoted technics (Mastouri, R. & al. 2015), should really improved the current model.

**References**


