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Construction of a naturally fractured tight reservoir model in a mature field

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1. Introduction

The Lower Eocene Mogollon Formation is the most important oil producer in Block X, which is located in Talara Basin in northwestern Peru (Figure 1). This formation is considered as a tight reservoir due to its matrix porosity (2-6%) and permeability (0.01-0.1md). As a result the average initial production rates per well of 500 bpd cannot be attributed to such low permeability matrix, but the presence of natural fractures (Benito, 2002). Pozo & Alvarado (2008) classified the Mogollon Formation as a naturally fractured reservoir of type II (Classification sensu Nelson, 2001), where mainly fractures provide permeability to the reservoir and matrix mainly contributes to the storage of fluids. Because of this it was necessary to characterize the natural fracture systems and know how these systems are distributed in the reservoir.

Previous studies carried out by Benito (2002) determined based on interpretations of borehole images that the orientation of fractures is associated with major faults and fracture density by the distance to faults. Roldan et al. (2013) obtained important mathematical relationships to calculate the density of fractures (open and closed fractures) with respect to the distance to a fault from outcrops, also determined orientations, geometries and apertures of fractures building for the first time a 3D fracture model in Block X. However, these studies left many unknowns, such as high production away from faults.

Despite these efforts, it has not been able to construct a fracture network model to understand and predict the distribution of natural fractures in the reservoir and its relationship with rock mechanics and the current tectonic stress.

This paper presents a methodology to generate a 3D model of the fracture networks that contribute to fluid flow in an area called Peña Negra in the Block X (Figure 1) by integrating geological models, outcrop information, core data, and well logs.

2. Identification of natural fractures

Based on the integration of outcrops, core analysis, borehole images, interpreted structural sections and dynamic information (well testing, production and lost circulation) (Figure 2) was determined that production in the Mogollon Fm. in the area is mainly controlled by open fracture networks. This gave rise to characterize the fracture systems which contribute to fluid flow in the reservoir.

3. Characterization of fracture networks

To characterize the natural fracture networks, attributes involving intensity, orientation, geometry and aperture were determined.

For the intensity fracture model, borehole image logs of various wells were integrated with spontaneous potential, gamma ray, resistivity, density and sonic logs. This allowed us to obtain a rock type (fracture type) classification log for each well. Three rock types were defined for these logs, namely as High, Moderate and Low. High is characterized by rocks with a high degree of fracturing and/or open fractures; Moderate represents rocks with a moderate fracturing and/or partially open fractures; and Low are rocks with closed fractures or without fractures. Each of these types has a fracture intensity distribution obtained from borehole image logs. These rock type logs were used to obtain the 3D model of rock type and fracture intensity using the sequential indicator simulation (SIS) technique and the sequential Gaussian simulation (SGS) technique respectively (Figure 3).

The orientation of natural fractures was achieved interpreting borehole images logs (Figure 4). The orientation of the horizontal stresses (maximum and minimum) based on breakout analysis (average orientation of N40°W) also were defined. Geometry (width and height) of fractures were obtained from outcrops (Figure 4). Aperture measurements were obtained from core data of 3 wells, an outcrop in Qda. Mogollon and borehole image logs (Figure 4). However, only measurements of filled or cemented fractures in cores were considered as input data in the model because it was not able to obtain measurements in fragments of broken rocks corresponding to the most fractured intervals of the cores. The average values obtained for the rock type high and low are 1.80 mm and 0.6 mm respectively.

Table 1 shows a summary of the parameters for the fractures that contribute to fluid flow.

4. Fracture Network modeling

The integration of rock type model, fracture intensity model and attributes of orientation, geometry and aperture in the modeling software made possible the construction of the 3D fracture network model, which is composed of a discrete fracture network (DFN) model and an implicit fracture model (IFM) (Figure 5). In the first model, natural fractures with a length greater than a set value are explicitly represented as 3D fracture planes with an established geometry; in the second, the remaining fractures are statistically represented by a grid with properties (Figure 5).

Then the fracture network model is upscaled from a grid of 100x100x3ft to a grid of 100x100x30ft to obtain the attributes of fracture porosity, fracture permeability (direction i, j, k), fracture sigma and mean fracture spacing (direction i, j, k) for reservoir simulation purposes (history match), which is beyond the scope of this work.

5. Extrapolation to other areas

The modeling technique was applied to other areas where it is thought that there are still open fractures that have not been drained by the influence of other wells. This led us to establish other development strategies, such as drilling horizontal or high angle wells in a direction parallel to the minimum horizontal stress in the most fractured intervals (Figure 6) in order to obtain a greater contact area with fractures networks. This will impact directly on increasing the recovery factor of the Mogollon Formation.

7. Conclusions

The methodology used in the 3D fracture network modeling for the studied reservoir allowed us to understand the distribution of fracture networks that contribute to fluid flow. This resulted in the formulation of new development strategies in areas where there are opportunities of finding fracture networks that have not been drained which allow improving the recovery factor.

Acknowledgments

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Illustrations

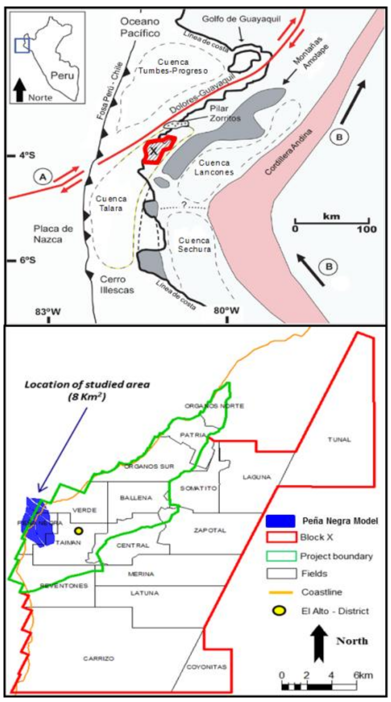

Figure 1. Location of Block X (upper) and study area (lower).

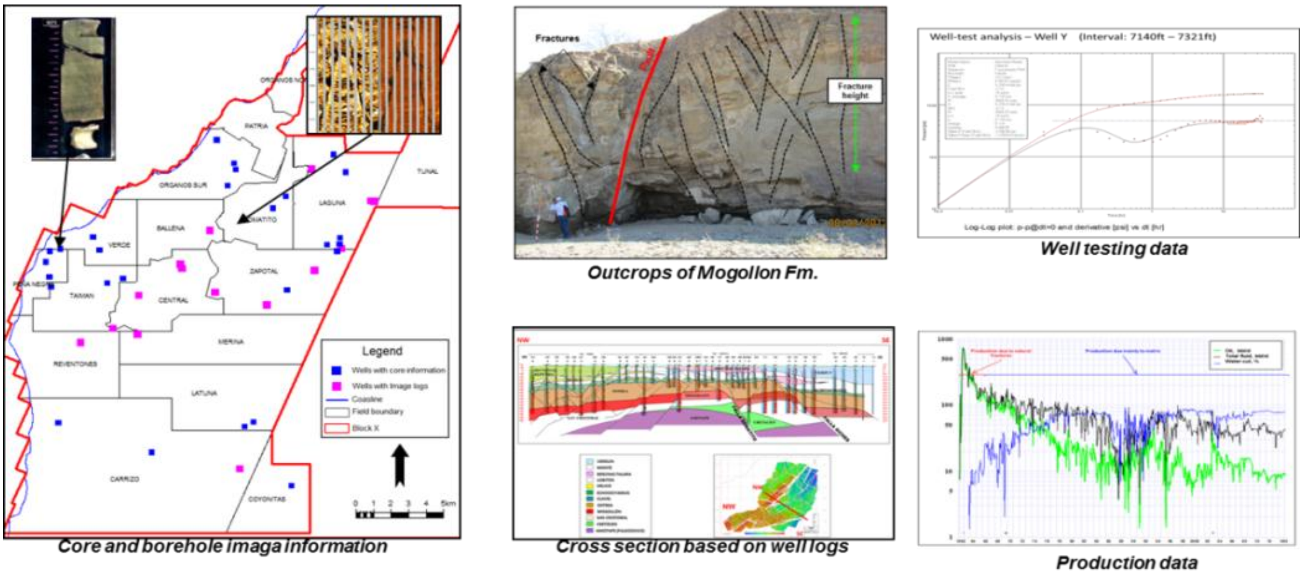

Figure 2. Information used to determine the impact of fracture networks in the fluid production of the Mogollon formation.

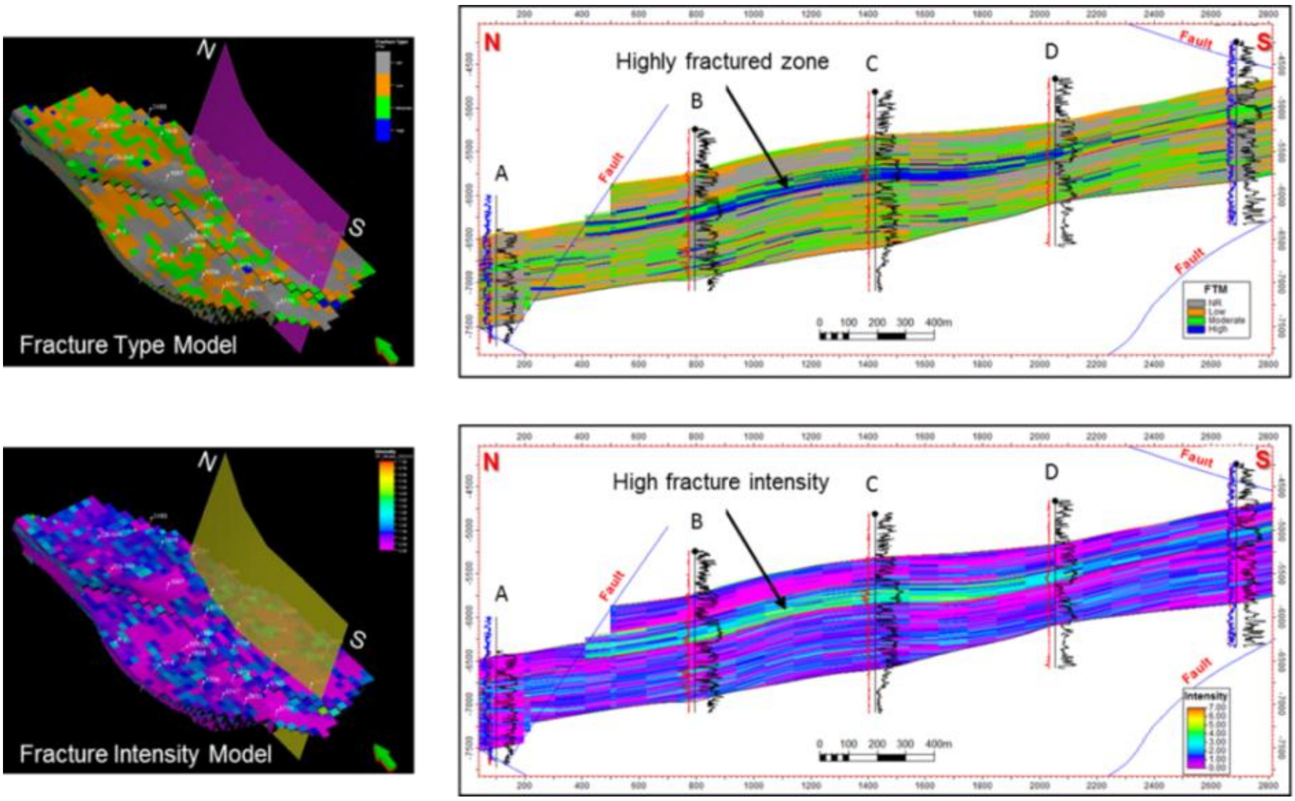

Figure 3. Rock or fracture type and fracture intensity models obtained from the integration of well logs. Observe the intervals that fracture more easily characterized by rock type high and a high fracture intensity values.

Fracture parameter for modeling natural fracture networks (Peña Negra field)						
Fracture type model	**Characteristics**	**Mean fracture intensity**	**Orientation**		**Mean Length (m)**	**Mean Aperture (mm)**
Moderate	Facies with partially open fracture and moderate fracture density	0.78	Main Strike	N50°E	80	0.61 mm
			Main Dip angle	65°		
High	Facies with Open fractures and high fracture density	1.32	Main Strike	N°50°E	80	1.83 mm
			Main Dip angle	70°		

Table 1. Summary of parameters found for the natural fracture networks that contribute to fluid flow (type high and moderate)

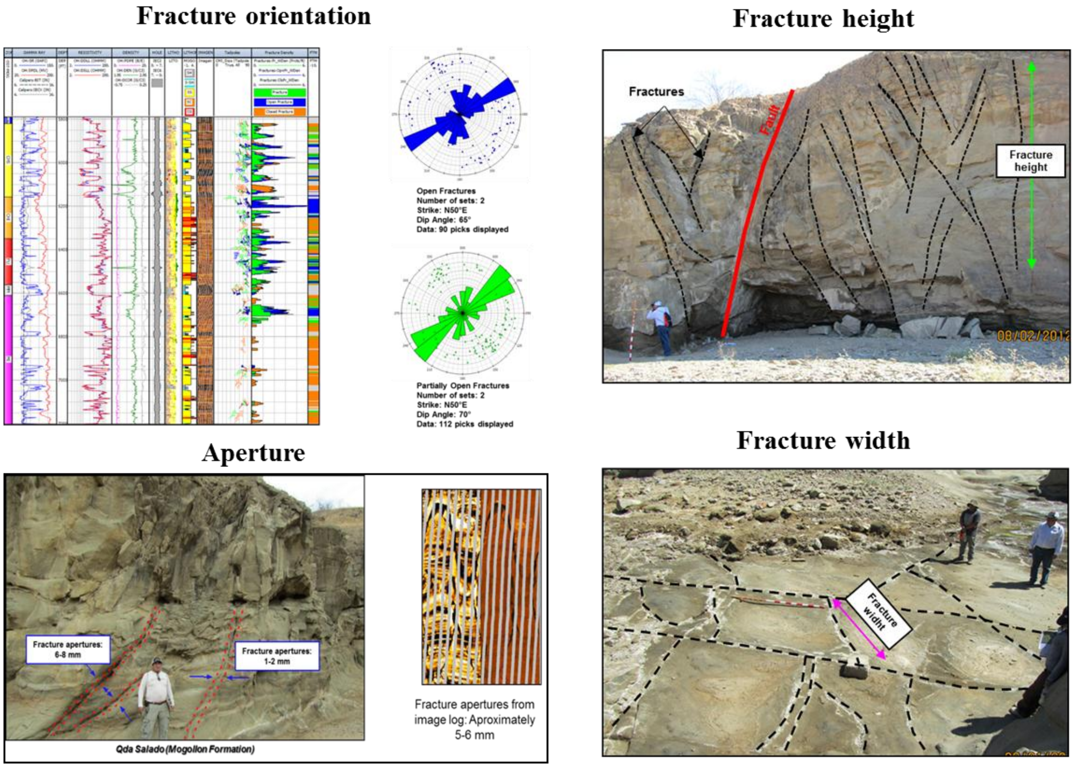

Figure 4. Information used to characterize natural fracture networks.

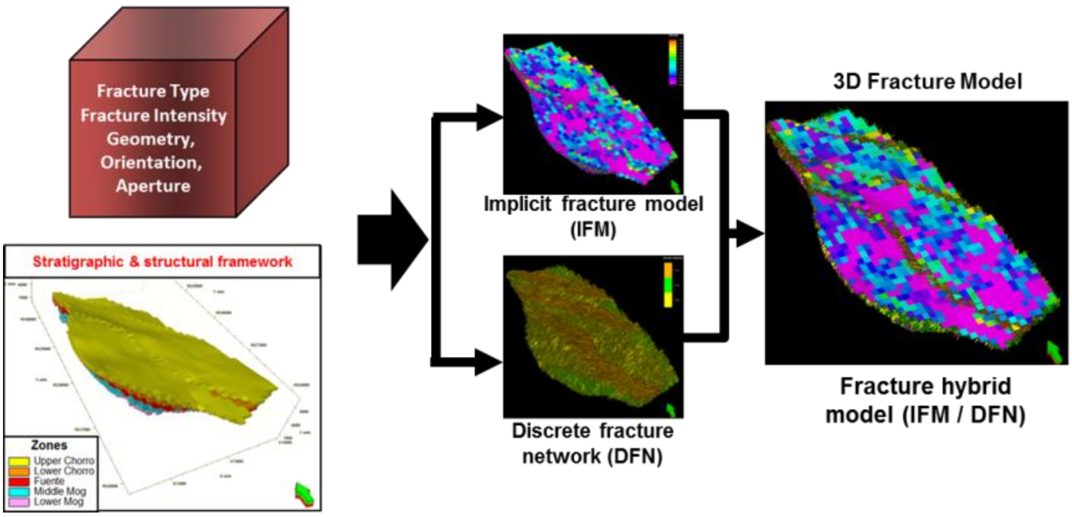

Figure 5. Attributes of fractures and structural framework of the reservoir were integrated to obtain the 3D fracture model consisting of the discrete fracture network and implicit fracture model.

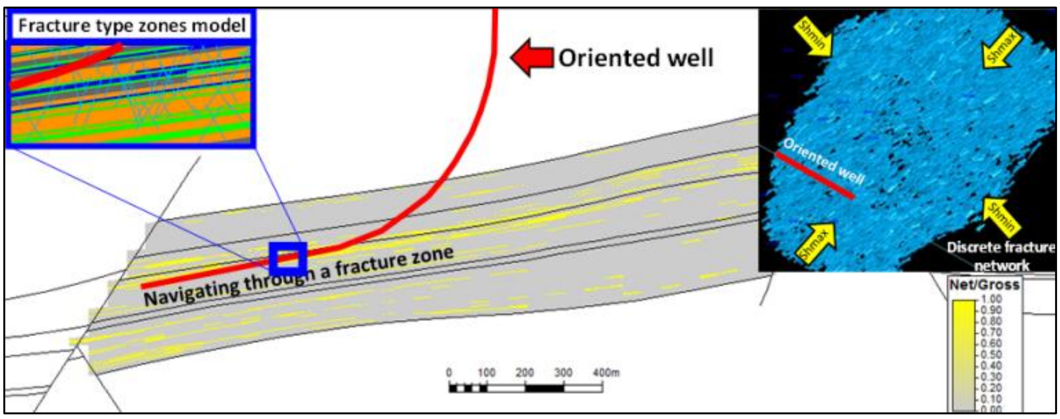

Figure 6. Development strategies were proposed from the characterization and generation of the 3D fracture model to increase the recovery factor.