The Mogollon reservoir of Eocene age, located in Block X of the Talara Basin, has been developed since the 1950s by hydraulic stimulation of vertical wells. Given its low porosities (2-6%) and permeability (0.01-0.5md), there is tight reservoir behavior, recovering to date only 5% of the original oil in place. The basin actually has high production variability, due primarily to the existence of sets of natural fractures, which contribute 80% of the cumulative production. These drained fractures show high degrees of depletion.

Due to the lack of understanding the distribution of natural fractures in the reservoir and the poor-quality information in the field, a characterization study was performed to construct a three-dimensional fracture model that allow us to understand and predict the productive performance of this reservoir.

This work focuses on the construction of the fracture model and its calibration with production history. To achieve this goal, an area within Block X was selected to generate a 3D fracture model, which was useful in understanding the behavior of the reservoir production. The characterization of this model was initiated by the identification and classification of natural fractures for each well, based on information from conventional cores, well logs, and outcrops that allowed us to obtain the main attributes of the fractures, and then build the 3D fracture network model, which represents the distribution of open fractures within the reservoir.
The results of the simulation for this model show that there is a strong capillary-water release from matrix. This water acts to displace the remaining oil from fractures. Thus, the recovery factor for fractures reaches a maximum of 60%. At the same time, it shows that there is still remnant oil has not been extracted efficiently; so there are sets of fractures that have not been drained. This leads to the possibility of drilling additional wells in order to obtain a larger contact area in these sets of fractures and to increase efficiency in the recovery within the reservoir.

Finally, the generation and calibration of this model served to understand the distribution of fracture sets (drained and undrained) and matrix-fracture behavior involving fluid-flow system. Furthermore, this methodology is being extrapolated to the rest of Block X to identify possible areas where fractures have not been drained yet within the Mogollon reservoir.

Selected References


CONSTRUCTION AND CALIBRATION OF A FRACTURED TIGHT RESERVOIR IN A MATURE FIELD

GTW - 2015

J. Marin (Presenter), D. Escobedo
Introduction
Objectives
Available data
Identifying fractures
Fracture sets characterization
Modeling natural fracture networks
Validation of the reservoir model
Possible drilling strategies
Conclusions
Introduction

Located in the Talara Basin on Peru’s northern coast, Block X has a total extension of 470 km² and 3,226 active wells out of over 5,000 total drilled to date.

Sedimentary fill of Talara Basin is roughly 9,000 meters thick with main productive intervals of the Eocene period.

Talara’s stratigraphic column is functionally divided into three depth categories to designate productive reservoirs: Shallow / Intermediate, Mogollon and Deep.

Talara’s structure and stratigraphy are highly complex, exhibiting low porosity and permeability.
Objectives

- Identify the natural fractures and their distribution in a tight reservoir
- Construction of a fractured tight reservoir model
- Calibration of the 3D fracture network model with historical production
Available data – Mogollon Fm

- Field observations (25 km to the southeast)
- Structural features: Interpreted cross sections based on well logs
- Core analysis (stratigraphic and petrophysical studies)
- Well logs (borehole images)
- Dynamic data (well testing, production, mud losses)
Fractures (dashed black lines) related to normal fault (red line) with azimuth/dip: N340°/50° in Qda. Salado (25 km to the southeast of Block X), Mogollon Formation.
Identifying fractures – Structural features

Interpreted structural section based on well logs

Type Log For Mogollon Fm.

<table>
<thead>
<tr>
<th>Stratigraphic Units</th>
<th>Type Log</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ostrea Fm.</td>
<td></td>
</tr>
<tr>
<td>Chorro Superior</td>
<td></td>
</tr>
<tr>
<td>Chorro Inferior</td>
<td></td>
</tr>
<tr>
<td>Upper</td>
<td></td>
</tr>
<tr>
<td>Fuente</td>
<td></td>
</tr>
<tr>
<td>Mogollon Fm.</td>
<td></td>
</tr>
<tr>
<td>Middle</td>
<td></td>
</tr>
<tr>
<td>Lower</td>
<td></td>
</tr>
<tr>
<td>San Cristobal Fm.</td>
<td></td>
</tr>
</tbody>
</table>

Legend:
- VERDUN
- MONTE
- BRECHAS TALARA
- LOBITOS
- HELICO
- ECHINOCYAMUS
- CLAVEL
- OSTREA
- MOLLÓN
- SAN CRISTOBAL
- CRETÁCEO
- AMOTAPE
- AMOTAPE (PALEOZOICO)
Identifying fractures – Core analysis

**Core porosity @ STD**
- Min: 1.01%
- Max: 8.63%
- Media: 4.53%
- Std. Dev.: 1.79%

**Core permeability @ STD**
- Min: 0.005md
- Max: 0.42md
- Media: 0.05md
- Std. Dev.: 0.06md

**Core water saturation @ STD**
- Min: 29.26%
- Max: 100%
- Media: 78.56%
- Std. Dev.: 26.37%
Identifying fractures – Core analysis

Well A
Massive Sandstone with no visible fractures

Well B
Fractures filled with calcite in sandstones

Well C
High fracturing in sandstones

Well D

Well E
Conglomerate
**Identifying fractures – Core analysis**

**Well A**
- Depth: 6330 ft
- Porosity: 5.76 %
- $K_{gas}$: 0.0331 md
- @ 2800 psi

**Well B**
- Depth: 6356 ft
- Porosity: 4.57 %
- $K_{gas}$: 0.0079 md
- @ 2800 psi

*Magnification 40X*

Medium-grained sandstone with moderate grain sorting. Secondary porosity is present (dissolution and microfractures).

*Magnification 200X*

- Microfractures in quartz grain
- Secondary porosity: dissolution and microfractures

Moderately poorly sorted, medium grained sandstone.
Identifying fractures – Borehole image log
Identifying fractures – Dynamic data

Well-test analysis – Well X (Interval: 5407ft – 5887ft)

Data for tested interval
Hn = 60
Phi = 0.063
Sw = 0.581
K = 0.051

KH from well test interpretations (md.ft) 114
KH from logs (md.ft) 3.1
FCI: Fracture capacity index (Narr et al., 2006) 37.3
Identifying fractures – Dynamic data

Data for tested interval

- $H_n = 20$
- $\Phi = 0.051$
- $S_w = 0.593$
- $K = 0.035$

KH from well test interpretations (md.ft) 15

KH from logs (md.ft) 0.70

FCI: Fracture capacity index (Narr et al., 2006) 21.4
Identifying fractures – Dynamic data

Production due to natural fractures

Production due mainly to matrix

- Oil, bbl/d
- Total fluid, bbl/d
- Water cut, %
Fracture sets characterization – Case study: Peña Negra

Parameters involved in the fracture characterization:

- Distribution (lithofacies, fracture type, and intensity)
- Orientation (strike and dip angle of fractures)
- Geometry
- Aperture
Fracture sets characterization – Fractures in lithofacies

Number of fractures per lithofacies

- Frequency
- Cumulative %

Fracture number

- Shale-Sandstone
- Sandstone
- Conglomeratic sandstone
- Conglomerate

Core data in Chorro Inferior
Fracture sets characterization – Fracture type classification

Fracture Intensity Histogram
Min: 0.20  
Max: 1.75 
Media: 0.55  
Std. Dev.: 1.65

Fracture Intensity Histogram
Min: 0.16  
Max: 3.93  
Media: 0.78  
Std. Dev.: 2.04

Fracture Intensity Histogram
Min: 0.28  
Max: 5.88  
Media: 1.32  
Std. Dev.: 1.92

Fracture Intensity Histogram
Min: 0.20  
Max: 1.75  
Media: 0.55  
Std. Dev.: 1.65
Fracture sets characterization – Fracture type classification

Fracture type based on image log interpretation

Fracture type model based on neural networks
Fracture sets characterization – Fracture type & Intensity

- Fracture Type Model
- Fracture Intensity Model

Highly fractured zone

High fracture intensity
Fracture sets characterization – Fracture type & Intensity

Quality control in a well that belongs to the model

Permeable intervals (in yellow) based on the Microlog

High fracturing observed in fine to medium grained sandstones

High fracturing observed in medium grained sandstones
Fracture sets characterization – Stress Orientation

Breakout analysis

Fracture system – Upper Mogollon

Breakout data
Depth: 7058 ft
Dip angle: 85°
Dip Azimuth: 326°
Width: 36°
Height 20.6 ft

Source: E. Bustamante, 2013
Fracture sets characterization – Fracture Orientation

Open Fractures
Number of sets: 2
Strike: N50°E
Dip Angle: 65°
Data: 90 picks displayed

Partially Open Fractures
Number of sets: 2
Strike: N50°E
Dip Angle: 70°
Data: 112 picks displayed
Fracture sets characterization – Geometry

✓ Length of fractures were determined from outcrops in Qda Salado. Fractures with great extent are mainly vertical to sub-vertical. A power law was assumed.

Mogollon Fm. in Qda Salado showing the geometry of the natural fractures
Fracture sets characterization – Aperture

- Apertures were measured in outcrops, cores and image logs. A log-normal distribution was given to the model.

Fracture apertures from image log: Approximately 5-6 mm
Modeling natural fracture networks

<table>
<thead>
<tr>
<th>Fracture type model</th>
<th>Characteristics</th>
<th>Mean fracture density (#Fract/ft)</th>
<th>Orientation</th>
<th>Mean Length (m)</th>
<th>Mean Aperture (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moderate</td>
<td>Facies with partially open fracture and moderate fracture density</td>
<td>0.78</td>
<td>Main Strike N50°E</td>
<td>80</td>
<td>0.61 mm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Main Dip angle 65°</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High</td>
<td>Facies with Open fractures and high fracture density</td>
<td>1.32</td>
<td>Main Strike N5°50°E</td>
<td>80</td>
<td>1.83 mm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Main Dip angle 70°</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Fracture network model
Modeling natural fracture networks

DFN model for fractures, showing the control of fracture types classification on fracture density.
**Modeling natural fracture networks - Upscaling**

Upscaled fracture network attributes for simulation purposes

- Fracture porosity
- Fracture permeability (I,J,K)
- Fracture sigma
- Mean fracture spacing (I,J,K)
Validation of the reservoir model – History match for the whole model

Initial history matching results for the Peña Negra model

- Initial Pressure, psi: 3150
- Current Pressure, psi: 400
- Cumulative Oil, MMBls: 6.5275
- Original Oil In Place, MMbbls: 18.65
- Recovery Factor $m+f, \%$: 35%
Validation of the reservoir model – History match for one well in the model

- Well A – OIL RATE
- Well A – WATER RATE
- Well A – BOTTOM-HOLE PRESSURE
- Well A – GAS RATE
Calibration of the fracture model
Possible drilling strategies

This methodology is being extrapolated to other parts of the Block X, as in the field of Somatito where new drilling strategies are being proposed.
Conclusions

- The construction of the natural fracture network model was validated by the simulation model.
- Fluid flows come mainly from natural fracture networks in Mogollon Formation (Tight Sand Reservoir).
- Fractures are open in the direction of the least principal stress and align with the direction of the maximum horizontal stress.
- It is still possible to find undrained sets of fractures in the direction of the least principal stress and establish new development strategies.
- Possibility of drilling additional wells in order to obtain a larger contact area in these sets of fractures and to increase efficiency in the recovery within the reservoir.
THANK YOU FOR YOUR ATTENTION