Discrete Fracture Network and Fractured Reservoir Characterization in
Khabaz Field-Tertiary Formation

1Adnan A. Abed and 2Samera H. Mohammed
1Department of Petroleum Engineering, University of Kirkuk, Kirkuk, Iraq
2Department of Petroleum Engineering, University of Baghdad, Baghdad, Iraq

Abstract: Fracture reservoirs contain most of the oil reserves of the Middle East. Such reservoirs are poorly
understood and recovery from fractured reservoirs is typically lower than those from conventional reservoirs
loaded the fracture dip and dip azimuth data of fractures from 10 wells using Petrel 2013. Generated fracture
intensity log and interpreted fracture data was used to make stereonet plots to study the fracture orientation.
The N130 fracture replication in the tertiary is intimately related to the proximity of large faults and the maximum
density is reached in a crestal position. Fracture density increases over some structural surfaces as Jeribe and
Anah limestones which systematically appear as the most competent/“fracturable” formations. Permeability
expected consistency between the fracture corridor occurrence and the highest values of permeability. The
permeability ranges between 2 and 1000 mD. Results of fracture upscaling; the fracture porosity ranges
between 0.0004 and 0.06 p.u. fracture-matrix coupling (sigma) ranges between 0 and 1 [ft]2.

Key words: Fractured modeling, DFN, intensity, Middle East, fracture, appear, systematically

INTRODUCTION

Fractured reservoirs are challenging to model due to the complexity of processes involved in the construction
and preservation of the fracture network as well as the heterogeneity reservoir. An understanding of stress
directions and natural fracture patterns within the basin are imperative in well design and completion. By
exploiting natural fractures with an optimum well design, an operator can ensure maximum hydrocarbon recovery.
The fracture model is used to build a dual porosity model in Petrel that incorporates both matrix and fracture
properties. Using regional fracture trends and available field data a fracture model for tertiary formation in Khabaz
field.

In this study, the discrete fracture network modeling provides a geologically sound representation based on
parameters (fracture orientation, length, aperture) and the means for up scaling is to a dual medium model that can
be simulated using it is a stochastic representation that can be used to estimate the uncertainty and the
heterogeneity of the output variables (fracture porosity, permeability, etc.)

Discrete fracture networks will be upscale into the developed matrix model of similar resolution by Oda (1985)
to generate the fracture porosity, the three permeability tensors and the matrix to fracture coupling factor.

Theoretical background

The Discrete Fracture Network (DFN) approach is commonly used to estimate fracture permeabilities. DFNs
are stochastic representations of the fracture network constrained by a wide range of reservoir data. The DFN
approach is an efficient and geologically consistent way, to model multiscale fractures as it can capture the
connectivity and scale dependent heterogeneity of the fracture system (Dershowitz et al., 2000; Wei, 2000;
Makel, 2007; Spence et al., 2014). In a DFN Model, fractures are represented by planar elements. To build a
DFN constrained by deterministic observations of fractures, five geometrical fracture characteristics that
control the interconnectedness of the subsurface fracture network are required. These characteristics include
the fracture intensity/density, orientation, aperture, length and aspect ratio. Multiple equiprobable realisations of
the fracture system can then be generated stochastically with a given set of input parameters to account for
uncertainties in the fracture network characterisation. For example, the fracture intensity in a given reservoir may
be generated as a result of faulting and hence cluster around faults (fault related intensity), may be part of a more
stratigraphically confined fracture system giving rise to layered high fracture permeability (bedding related

Corresponding Author: Adnan A. Abed, Department of Petroleum Engineering, University of Kirkuk, Kirkuk, Iraq
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intensity) or part of a pervasive background fracture
system (regional intensity). Analysing the influence of
fracture intensity scenarios on hydrocarbon production
in a given reservoir will enable us to link flow patterns to
the fracture network characterisation, especially, for EOR
simulation. Hence, a systematic and integrated analysis of
the fracture network geometry can provide a pathway
to better understand the fracture system, fracture
ctribution to subsurface fluid displacement, the best
way to accurately model the fracture flow impact and to
develop the reservoir accordingly.

Discrete fracture network upscaling: In standard
reservoir simulation applications that use
conventional finite difference formulation, the DFN
fracture representation is employed in dual continuum
models. The effective properties for the fracture medium
are obtained via. analytical or flow based fracture
upscaling methods (Dershowitz et al., 2000). Analytical
upscaling methods such as the Oda (1985) method are
usually preferred for field-scale applications due to the
significant computational efficiency compared to
flow-based upscaling but can be inaccurate for poorly
connected fracture networks (Elfeel and Geiger, 2012).
Generally, the upscaling of the DFN must be done with
utmost care to ensure that geological uncertainties
captured in the DFN are not masked by uncertainties in
the upscaling step. The effective fracture porosity, \( \phi_f \) is
calculated as Eq. 1:

\[
\phi_f = \frac{P32*af}{932}
\]  

(1)

where, P32 represents the volumetric fracture intensity
(total fracture area per unit volume) and a f denotes the
fracture aperture.

Oda fracture permeability upscaling: Oda (1985) to
compute the effective fracture permeability for a specific
simulation grid cell from a DFN Model, a permeability
tensor, \( F_f \) which denotes flow along the fracture’s unit
normal, n, needs to be estimated. The tensor is calculated
by summing over the individual fractures, f in the grid cell
provided the fracture area, \( A_f \) and transmissibility, \( T_f \) are
known Eq. 2:

\[
F_f = \frac{1}{V} \sum_{i=1}^{n_i} A_i T_i n_i n_f
\]  

(2)

where, the number of fractures is denoted by N, the
fracture unit normal representing its direction and
orientation is represented by \( n \) and the total fracture pore
volume is represented by V. If \( F_f \) is rotated into the planes
of the permeability tensor by multiplication with \( \delta_f \),
the fracture permeability can be approximated as
(Dershowitz et al., 2000) Eq. 3:

\[
k_f = \frac{1}{12} \left( F_f^2 \delta_f F_f \right)
\]  

(3)

where, \( F_f \) defines the principal directions of the
permeability. The application of Oda’s method is based on
equation above is the assumption that fractures of any
length will contribute to the upscaled permeability even if
fractures do not form a percolating network in the grid
block. Therefore, a modified version of Oda’s method was
introduced for situations where fractures are not
connected in a grid block (Anonymous, 2010) Eq. 4:

\[
k_f = M \left( F_f^2 \delta_f F_f \right) + MC \left( F_f^2 \delta_f F_f \right), C \geq C_0
\]  

(4)

Where:

\( M \) = A multiplier for scenarios where fractures are not
connected
\( C_0 \) = Determines the threshold fracture connectivity

MATERIALS AND METHODS

Loading data and fracture analysis: Loading and
fracture data analysis is the next step in the reservoir
characterization and modeling workflow. Loaded the
fracture dip and dip azimuth data of fractures from 10 wells
in the Fetel project depend on previous study of that
based upon Qara Chauq anticline analogy to build a
structural framework (faults and fractures network).
Generated fracture intensity log in these wells and
analysis of fracture by tadpole concentration at wells
interpreted fracture data was used to make stereonet
plots for tertiary formation in Khabaz field to study the
fracture orientation. The general directional rose diagram
indicates that the major part of the fractures is parallel
to the fold axis. Statistically, this direction tends to
appear over-represented with respect to the other trends
(Fig. 1 and 2).

Fracture network modeling: After loading and
fracture analysis data the discrete fracture network
modeling representation provides a geologically sound
representation based on physically measurable
parameters (fracture orientation, length, aperture) and the
means for up scaling is to a dual medium model that can

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Fig. 1: Tadpole and rose diagram for dip and azimuth of fracture in KZ-20

Fig. 2: Continue
Fig. 2: a) 2D intensity map and stereonet plot of all fracture dip angle and b) dip azimuth in tertiary reservoir

be simulated using it is a stochastic representation that can be used to estimate the uncertainty and the heterogeneity of the output variables (fracture porosity, permeability, etc.). Discrete fracture network modeling was constructed depend on fracture distribution, geometry, orientation and fracture aperture.

RESULTS AND DISCUSSION

Fracture distribution: Fracture density measurement is crucial in the discrete fracture network model generation, to be able to quantify the fracture intensity in a 3D grid.

Fracture orientation: Finally, the orientation of the fractures in terms of dip angle and azimuth is defined according to the well data; the choice of the distribution is done on the stereonet of the sets of potential flow contributing fractures with specific orientation. A different orientation is defined for each fracture set.

Fracture aperture: Fracture aperture is a perpendicular width of the fracture. Previous research showed that the fracture aperture distribution follows lognormal distribution (Keller, 1996; Gale, 1987). The lognormal distribution is described by the mean and standard deviation.

Applying the approach for discrete fracture network, field data was analyzed. Overall, the trend of all natural fracture orientations is NE-SE and some SE-SW, (Fig. 3a, b).

Three different fracture scales have been referenced generally reducing 4 principal direction trends; N135 Normal faults (identifying throw values from 10-100 m) in segmented arrays, N45 and N135, fracture swarms and background diffuse fractures (N15, N45, N105, N135). The N130 fracture repartition in the tertiary is intimately related to the proximity of large faults and the maximum density is reached in a crestal position. This direction constitutes the best represented trend over the study area.

The N35 fracture system should have a systematic distribution (tensile jointing) under the early beginning of the NE-SW shortening. Diffuse fractures and significant fracture swarms theoretically affect tertiary by the same deformation processes. Fracture density increases over some structural surfaces as Jeribe and Anah limestones which systematically appear as the most competent/“fracturable” formations.

The visible part of the Azkand (reef facies) emerges less fractured (Fig. 4).

Discrete fracture network upscaling: A discrete fracture network model is made with some fracture network attributes as described above. However, for
Fig. 3: a) 2D dip azimuth of fracture in tertiary reservoir and b) 3D dip azimuth of fracture in tertiary reservoir

Fig. 4: Streonet plot of fracture type in tertiary reservoir
Fig. 5: 3D fracture permeability in tertiary reservoir

Fig. 6: 3D fracture porosity in tertiary reservoir

practical purposes in dynamic reservoir models, these are not useful, until they are upsampled into the required grid properties that can be used for simulation. Each of these discrete fracture networks were upsampled into the already developed matrix model of similar resolution by Oda (1985) to generate the fracture porosity, the three permeability tensors and the matrix to fracture coupling factor.

**Property modeling incorporating fracture network:** Results of fracture upscaling: permeability expected consistency between the fracture corridor occurrence and the highest values of permeability. The permeability ranges between 2 and 1000 mD. Results of fracture upscaling; the fracture porosity ranges between 0.0004 and 0.06 p.u. fracture-matrix coupling (sigma) ranges between 0 and 1 1/ft^2 (Fig. 5-7).
CONCLUSION

Discrete fracture network modeling and fracture characterization were constructed depend on fracture distribution, geometry, orientation and fracture aperture which means for up scaling is to a dual medium model that can be used to estimate the uncertainty and the heterogeneity of the output variables (fracture porosity, permeability, etc.).

The N130 fracture repartition in the tertiary is intimately related to the proximity of large faults and the maximum density is reached in a crestal position. This direction constitutes the best represented trend over the study area.

Fracture density increases over some structural surfaces as Jeribe and Anah limestones which systematically appear as the most competent/“fracturable” formations. The visible part of the Azkan (reefal facies) emerges less fractured.

REFERENCES