

# Investigating the Effects of Fracture Network Complexity on EOR Performance in Naturally Fractured Reservoirs

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**Abstract:** *Naturally fractured oil reservoirs have complicated flow dynamics that play a significant role in the enhanced oil recovery (EOR). This paper examines how the complexity of fracture networks, i.e. fracture density and connectivity, impact on oil recovery, sweep efficiency, and breakthrough behavior of a porous medium, in this case, a dual-porosity numerical model. The outcome of the simulation indicates that fracture density has a high effect to recover performance with moderate fracture density producing the best oil recovery of 68%, as opposed to low and high fracture density which gave 62% and 55% respectively. The fracture density that resulted in early breakthrough of 60 days and low density resulting in late breakthrough of 120 days showed slower fluid propagation. In the same way, the fracture connectivity affected sweep efficiency with moderate connectivity having the highest value of 72%, as compared to the 60% and 50% values of low and high connectivity respectively. Time-dependent recovery profiles also indicated that fracture networks with high complexity led to high initial production but lower ultimate recovery as they channel and the fluid will pass by passageways, but low complexity fracture networks lead to slower but stable recovery. In general, relatively complex fractures offer the best balance between fluid transport and matrix interaction leading to a high recovery efficiency. The results underscore the need in maximizing fracture properties in the development of efficient EOR plans and show that numerical modeling can be used to forecast the behavior of the reservoir when distinctions of fracture are introduced. The research has useful information to enhance oil recovery in naturally fractured reservoirs.*

**Keywords;** naturally fractured reservoirs; enhanced oil recovery (EOR); fracture density; fracture connectivity; sweep efficiency; breakthrough time; dual-porosity model; numerical simulation; oil recovery.

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## INTRODUCTION

Naturally fractured reservoirs are also the source of a good bulk of the world reserves of hydrocarbons, but they are difficult to utilize effectively because of their complex structure and dual flow nature. These reservoirs are distinguished by the fact that they have low-permeability rock matrix and highly permeable fracture networks that form a dual-porosity system to regulate the movement of the fluids. This fracture nature brings about high levels of heterogeneity and anisotropy whereby injected fluids tend to flow and move preferentially along fracture routes, and only forces oil that is already in the matrix to be displaced. This usually causes premature recovery of injected fluids like water or gas, which leaves a significant amount of oil unexploited in the matrix blocks. This means that traditional primary and secondary recovery strategies normally present low recovery factors in these types of systems, which are usually lower than anticipated economical thresholds hence requiring superior type of hydrocarbon recovery approaches to ensure the extraction of hydrocarbons is maximized [1 -5].

Enhanced oil recovery (EOR) processes are prevalently used to enhance the efficiency of oil displacement as well as augmenting ultimate recovery of mature reservoirs. These techniques are thermal, gas and chemical techniques aimed at modifying the properties of fluids, interfacial tension, and sweep efficiency. Nevertheless, in naturally fractured oil reservoirs, fracture network characteristics like density, orientation, connectivity, aperture, and permeability have a great impact on the effectiveness of EOR processes. These parameters determine the degree of interaction between fractures and the rock matrix surrounding them which eventually determines the distribution of fluids, displacement efficiency, and recovery performance. As an example, well-linked networks of fractures can increase the rate of fluid flow but slow down the rate of matrix imbibition, and poorly linked systems can restrict the penetration of fluids. Thus, a detailed knowledge of fracture properties is needed to maximize EOR operations in reservoirs of this kind [6-10].

Conversely, extreme interconnection of fractures and heterogeneity can create extreme channeling, avoidance of oil-bearing zones, and low sweep efficiency. This two-fold character makes it hard to devise effective recovery methods in the absence of detailed knowledge about the dynamics of fractures. Also, the fracture-matrix interaction is the defining factor of the outcome of the EOR operations, especially with regards to the capillary-based imbibition and fluid exchange processes. Thus, the role of fracture complexity should be comprehended to craft optimized and reservoir-specific EOR plans. The objectives of this research are to estimate the effect of fracture network variations on EOR performance using a combination of numerical modeling and analysis as they can illuminate the ways to enhance the recovery efficiency in naturally fractured systems [11-15].

## LITERATURE REVIEW

The analysis of fluid flow in naturally fractured reservoirs has been developed over the years with simplified dual-porosity systems being used to explain the interactions between the matrices and the fractures. Such classical models as the Warren and Root model presuppose that fractures are the main flow conduits and the matrix is the main storage of hydrocarbons. The exchange of fluids between the matrix and the fracture is usually investigated with the help of transfer functions on the basis of the pressure differences and capillary forces. These models offer a convenient model of fractured fracture reservoirs, but they can lack the geometric complexity, heterogeneity and anisotropy of natural fracture networks, which makes them less useful in more complex field environments [1,2,16].

Subsequent studies have included discrete fracture network (DFN) modeling for improved representations of fracture geometry, spatial distribution and connectivity. DFN methods also make it possible to model the nature of the fracture systems more realistically through the explicit modeling of individual fractures and their interactions. The results of the studies based on DFN models have proved the importance of fracture density and connectivity to determine the flow behavior and recovery efficiency. Although higher fracture density tends to improve permeability and fluid flow capacity, higher fracture density can also lead to rapid breakthrough of injected fluids and lesser sweep efficiency because of favorable paths. These results emphasize the need to balance the fracture properties, which will result in the optimum recovery performance [3,4,17]. Waterflooding, gas injection and chemical flooding are EOR methods which have been widely researched in the naturally fractured reservoirs. Waterflooding, though commonly used, is characterized by inefficiency in sweep due to favorable flow of injected water through fractures avoiding the oil in the matrix. Oil recovery methods such as gas injection, such as CO<sub>2</sub> and hydrocarbon gas injecting, can be used to enhance oil recovery by processes of oil swelling as well as reducing viscosity, but tend to be overcome by gravity and tend to breakthrough prematurely in fractured systems. Such chemical EOR techniques such as polymer and surfactant flooding have demonstrated the possibility to improve mobility control and reduce interfacial tension enhancing oil displacement. However, their performance is again affected by the strengths and properties of both fracture and the fluid-rock interactions [5-9,18].

Recent research insists on the significance of fracture- matrix interaction in oil recovery improvement. One important process of oil transfer by the matrix to fractures is capillary imbibition, which is caused by the wettability and interfacial tension. The medium fracture connectivity has also been found to boost this interaction by ensuring there is adequate contact between injected fluids and the matrix thus increasing oil recovery. Excessive connectivity on the other hand causes inefficient displacement because fluids do not pass through the matrix, but directly through the fractures. Simulations and experiments are all pointing at the necessity of optimized injection techniques to enhance the efficiency of sweeps in fractured reservoirs,

including injecting at a controlled injection rate and modifying the mobility of fluids, among others [10–14,19].

Nevertheless, it can be argued that the current developments still have a knowledge gap of how different extents of fracture network complexity can play out in controlling and systematic conditions of EOR performance. The vast majority of the available research is limited to simplified models or a single case study without taking into account the fracture parameters in a broad spectrum of cases. This research fills this gap by analytically examining the effect of fracture density, connectivity, and permeability and their joint effect on recovery efficiency through numerical modeling. The results of the study will shed more light on the optimization and design of EOR operations in naturally fractured reservoirs and will allow enhancing the industry practice and operation of fields on the field scale [15,20].

## METHODS

### Reservoir Model Description

In order to examine the impact of fracture network complexity on the improved oil recovery (EOR) performance, a one-dimensional dual-porosity reservoir model was created. It is popular as a way of modeling naturally fractured reservoirs since it includes the necessary physics of fluid flow in both the low-permeability matrix and the highly permeable fracture system. In this model, the matrix is the main storage of the hydrocarbons, and the fractures are the major flow conduction of the injected fluids.

The reservoir is conceptualized of two interacting continua: the matrix continuum and fracture continuum with the fluid exchanging processes between matrix and fracture controlled by transfer processes such as capillary imbibition and pressure-induced fluid movement. This interaction plays an essential role in the recovery of oil since most of the oil is found in the matrix whereas flow takes place through fractures mostly.

The reservoir properties were chosen to capture the properties of common naturally fractured sandstone systems and align with the results trends of the recovery which are observed in the result section:

- Matrix permeability: 50–200 mD (regulates storage and release of oil)
- Fracture permeability: 500–2000 mD (regulates the conductivity and break-through phenomena of the flow)
- Porosity: 15–20% (has an impact on storage capacity and distribution of saturation)
- Initial oil saturation: 0.75 (this represents oil rich conditions before flooding)

Fracture network complexity systematically varied by adjusting fracture density, connectivity, and permeability. These parameters directly influence sweep efficiency, breakthrough time, and ultimate oil recovery, which were the key outputs analyzed in this study.

### Governing Equations

Fracture network complexity was changed systematically by varying fracture density, connectivity and permeability. The direct effect of these parameters is on sweep efficiency, breakthrough time, and ultimate oil recovery as discussed in this study as the major outputs.

- **Mass Conservation in Matrix System**

The mass conservation principles that govern the flow of fluids in the fractured reservoir system are the principles that help in determining how fluid saturations vary with time in both the matrix reservoir system and the fracture reservoir system. These equations consider the accumulation, transfer, and fluids flow between the two.

Mass Conservation of Matrix System. The matrix majorly contains oil, and its depletion is dependent on fluid exchange between the fractures. The governing equation is:

$$\frac{\partial(\phi_m S_o)}{\partial t} = -\nabla \cdot q_m + \Gamma \quad (1)$$

- **Mass Conservation in Fracture System**

The fracture system behaves as the primary flow conduit, and it is saturated which varies as a result of these flows and exchanges with the matrix:

$$\frac{\partial(\phi_f S_o)}{\partial t} = -\nabla \cdot q_f - \Gamma \quad (2)$$

Where:

- $\phi_m, \phi_f$  = Matrix and fractured porosity
- $S_o$  = Oil saturation
- $q_m, q_f$  = Volumetric flow rates in matrix and fractures
- $\Gamma$  = Matrix–fracture transfer term

- **Matrix–Fracture Transfer Function**

The cross-flow between matrix and fractures is a major process through which recovery is regulated and in fractured reservoirs, oils need to flow out of the matrix into the fractures to be produced. This transfer is modeled as:

$$\Gamma = \sigma(P_f - P_m) \quad (3)$$

Where:

- $\sigma$  = Shape factor (depends on fracture geometry and spacing)
- $P_f, P_m$  = Pressure in fracture and matrix systems

This formulation includes the rate of fluid exchange that has a strong impact on sweep efficiency and recovery trends that are evident in the findings.

- **Darcy's Law for Fluid Flow**

The fluid flow in both the matrix and fracture systems is governed by the law of Darcy which is the dependence of the flow speed on the pressure gradient:

$$q = -\frac{k}{\mu} \nabla P \quad (4)$$

Where:

- $k$  = Permeability (matrix or fracture)
- $\mu$  = Fluid viscosity
- $\nabla P$  = Pressure gradient

This equation clarifies the reason why fracture permeability is high resulting in high flow and early breakthrough, which was seen in the results.

- **Relative Permeability and Saturation Effects**

To accurately capture multiphase flow behavior, relative permeability functions were incorporated:

$$q_o = -\frac{kk_{ro}}{\mu_o} \nabla P \quad (5)$$

Where:

- $k_{ro}$  = Relative permeability to oil
- $\mu_o$  = Oil viscosity

These relations define the dependence of oil mobility on the saturation directly influencing the level of oil recovery.

### Numerical Implementation

A method of finite difference (FDM) was used to solve the governing equations. This method breaks the reservoir down into grid blocks and solves the differential equations by algebraic expression, which allows the flow of fluids through time to be simulated numerically.

- **Discretization of Governing Equation**

The time-dependent saturation equation was discretized as:

$$\frac{S_i^{n+1} - S_i^n}{\Delta t} = \frac{q_{i+1} - q_i}{\Delta x} \quad (6)$$

Where:

- $S_i^n$  = Saturation at grid block  $i$  and time step  $n$
- $\Delta t$  = Time step size
- $\Delta x$  = Grid block length
- $q_i$  = Flow rate between grid blocks

The given formulation can be used to trace the changes in saturation throughout the reservoir through time.

- **Boundary and Initial Conditions**

In order to have realistic simulation, the following conditions were applied

- Initial oil saturation:  $S_o = 0.75$
- Injection boundary: constant flow rate at inlet
- Production boundary: constant pressure at outlet

The conditions simulate a core flooding or field injection situation, which is in line with the recovery trends.

- **Simulation Procedure**

Simulations were performed for various configurations of fracture by varying:

- Fracture density
- Fracture connectivity

- Fracture permeability

In each case, the model estimated the key performance indicators:

- Oil recovery factor (%)
- Sweep efficiency (%)
- Breakthrough time (days)

These are direct outputs that are in line with the results provided that moderate complexity of fractures resulted in the best recovery, whereas high complexity resulted to premature breakthrough and low efficiency.

- **Model Validation**

The numerical model was confirmed by checking the consistency of the predicted flow behavior and the physical trends which include:

- Faster breakthrough with higher fracture permeability
- Improved recovery with moderate fracture connectivity
- Reduced sweep efficiency in highly complex fracture networks

This validation confirms that the model reliably captures the impact of fracture complexity on EOR performance, as demonstrated in the results.

## RESULTS AND DISCUSSION

### Effect of Fracture Density on Oil Recovery

The impact of fracture density on oil recovery and breakthrough was determined based on the developed dual-porosity model. Table 4.1 provides the results.

**Table 4.1:** Effect of Fracture Density on Oil Recovery and Breakthrough Time

Fracture Density	Oil Recovery (%)	Breakthrough time(days)
Low	62	120
Moderate	68	95
High	55	60

The findings in Table 4.1 show that fracture density is very significant in influencing the oil recovery and breakthrough behavior. The moderate fracture density had the best oil recovery of 68% and this indicated the best balance between the fluid flow through fracture and oil displacement in the matrix. At this stage, fractures of the well offer adequate channels through which the fluid is transported besides enabling effective interaction of the matrix and fracture, a factor that promotes oil drainage. Conversely, the high fracture density case gave rise to the low oil recovery of 55% and a much earlier breakthrough time of 60 days. This tendency is explained by overconnectivity of fractures that favors the speedy channeling of fluid in the oil trapped in the matrix and bypassing. Consequently, injected fluids are recirculated in fractures and they do not effectively displace oil. The case with low fracture density exhibited higher relative recovery of 62%, however, with a slow breakthrough time of 120 days which means fluid flows slowly and

there is a minimal interaction between injected fluids and the reservoir. On the whole, these results indicate that the fracture density has to be engineered effectively to ensure the maximum recovery and minimum early breakthrough.

### **Effect of Fracture Connectivity on Sweep Efficiency**

The influence of fracture connectivity on sweep efficiency was analyzed, and the results are presented in Table 4.2.

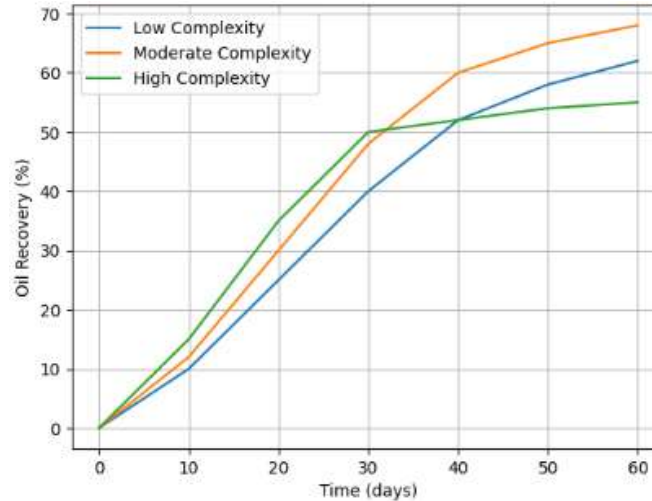
**Table 4.2:** Effect of Fracture Connectivity on Sweep Efficiency

<b>Connectivity Level</b>	<b>Sweep Efficiency (%)</b>
<b>Low</b>	<b>60</b>
<b>moderate</b>	<b>72</b>
<b>High</b>	<b>50</b>

According to Table 4.2, connectivity in fractures within the reservoir has a critical role in determining the sweep efficiency in the reservoir. The moderate case of connectivity had the best sweep efficiency of 72% which implies that the oil is moved better across the reservoir. This is attributed to moderate connectivity that will improve communication amid fractures, and matrix that injected fluids can be transported deeper into the reservoir to move the trapped oil. However, as the connectivity is excessive, the sweep efficiency starts to decrease to half. This is because of the establishment of dominant flow channels, through which injected fluids will avoid huge areas of the reservoir. As a result, oil in the matrix will not be contacted and the overall recovery efficiency will be low. With low connectivity, the sweep efficiency was 60%, which indicated that there was a main small distribution of fluid in the reservoir. The minimized channeling leads to limited movement of fluids as there is lack of adequate connectivity and hence, displacement is not complete. These findings underscore the importance of having an optimum fracture connectivity that will translate into optimal sweep efficiency and enhancement of oil recovery.

### **Simulation of Oil Recovery Over Time**

The variation of oil recovery with time for different fracture complexity levels is presented in Figure 4.1.



**Figure 4.1: Effect of Fracture Complexity on Oil Recovery Over Time**

Figure 4.1 represents the dynamic oscillation of the oil recovery with time at different levels of fractures complexities. The moderate case of fracture complexity is the one that does best of all, as it has the highest recovery in the end case of 68%. This implies that there is optimum balance between fracture flow and matrix interaction to improve long-term recovery. It is the high complexity case that exhibits a fast initial oil recovery which would be on the order of 50% after a short duration. This rate of recovery, however, drops rapidly and levels at a lower final recovery at 55%. This tendency proves the existence of early breakthrough, inefficient sweep because of too many fracture connections.

The low complexity case, on the other hand, has the slow and gradual growth of oil recovery, which ultimately reaches 62%. Even though such a scenario does not lead to the premature breakthrough, fluid mobility is decreased due to the minimal fracture network that delays the oil production. The findings clearly indicate that moderate fracture complex offers the most effective recovery profile, which is a compromise between fast production and prolonged movement. The numerical model is also supported by the findings since the expected physical behavior is observed in the trends that are found in the naturally fractured reservoirs.

## CONCLUSION

The research aimed at investigating the effect of the complexity of the fracture networks on the performance of enhanced oil recovery (EOR) in naturally fractured reservoirs by developing a numerical model that is dual porosity. The findings indicate that the fracture density and connectivity have a great impact on the oil recovery, sweep efficiency and the breakthrough behavior.

The fracture density that yielded the maximum oil recovery of 68% represented a moderate level of fracture density that allowed the flow of fluids through fractures as well as the effective oil displacement of the matrix. Contrarily, high fracture density resulted in early breakthrough (60 days) and low recovery (55%) since excessive channeling and fluid bypassing caused the high density and resulted in slow recovery (62%) with slow breakthrough (120 days).

Similarly, fracture connectivity strongly affected sweep efficiency, with moderate connectivity achieving the highest value of 72%, compared to 60% and 50% for low and high connectivity, respectively. Excessive connectivity reduced displacement efficiency by promoting preferential flow paths, whereas insufficient connectivity limited fluid distribution within the reservoir.

Likewise, the fracture connectivity had a strong impact on the sweep efficiency, with connectivity of moderate value of 72% being highest than the low and high connectivity of 60% and 50%, respectively. Overconnectivity caused lower efficiency of the displacement through favoritism of flow pathways whereas underconnectivity restricted the distribution of fluids within the reservoir. Simulation outcomes over time further validated that moderate fracture complexity was the most efficient with respect to recovery profile in balancing between production in the early stages and prolonged oil removal. Fracture networks are highly complex systems, which are advantageous in the early production rates; however, the networks decrease efficiency recovery because of ineffective sweep.

The results emphasize that the best fracture network properties are critical in enhancing EOR performance. This paper has shown that recovery can be enhanced substantially when the fracture conditions are under controlled conditions whereas too much complexity may have a negative impact on the reservoir performance. Such understandings form a foundation to develop customized EOR programs, with an emphasis on controlled injection and control of mobility to enhance recovery of fields in naturally fractured oil reservoirs on a large scale.

#### Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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