Hydrodynamics Behaviour of Single and Multi Fracture with Different Orientations in Petroleum Reservoir

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Abstract- **The studying of fluid flow throughout fracture in the reservoir is one of the most vital subjects attracted much attention from engineers and geologists. In the present paper, the Dual Porosity-Dual Permeability (DPDP) model has been applied to represent the fluid flow within the fractured reservoirs. This work aimed to demonstrate the utility of the fractures in the petroleum reservoir and how could be used the positive effect of these fractures on the productivity as well. The productivity of single-phase fluid flow within the single horizontal fracture, multi horizontal fractures, and inclined fracture with different orientations (20^o, 30^o, 45^o, and 70^o) have been implemented by using ANSYS-CFX program and compared with the productivity of conventional (without fractures) reservoirs. In addition to, visualize the velocity streamlines within fracture and matrix zones for the DPDP model. To verify this work the comparison has been made with published paper, which studies the fluid flow through fractures, and a good agreement has been obtained with each other. The study indicates that the presence of macro scale fractures in petroleum reservoirs contributes to increasing the total productivity of these reservoirs. Clearly, the productivity index of multi-horizontal fractures domain is more than twice of nonfractured domain. It is also clear that, when comparing the fractured and nonfractured reservoir, the improvement percentage of the productivity index reaches to (71.8) for a single horizontal fracture with 9 ft length. While this percentage would be about (116.88) if the fracture is inclined with 20^o.**

keywords :- CFD, Fracture, Orientations, Petroleum Reservoir.

Nomenclature

k	Permeability [Darcy]
s	The phase saturation
P	The phase pressure [Pa]
k_r	Relative permeability
g	Gravity acceleration vector [m/s^2]
u	Phase flux [m/s]
h	Fracture aperture [ft]
q^{m-f}	Volumetric flux from the matrix to the fracture domain
q^{f-m}	Volumetric flux from the fracture to the matrix domain
t	Time [s]
J	Productivity index [BBL/psi.Day]
Q	Flow rate [BBL/Day]
∇P	Pressure drop [psi]
Greek Symbols	
ψ	Volumetric source term
ϕ	Porosity
ρ	The density of uid [Kg/m^3]
θ	Angle
μ	Dynamic viscosity [Pa:s]

1. Introduction

To make a comprehensive idea about the fractured reservoir, it should have a simple idea about what is a fracture in advance. The definition of fracture; is a discontinuity of mechanical origin surface. So, the fracture is the rock deformation that obtaining from applied stresses. The fractured reservoir takes more attention from both geologists and reservoir engineers. According to geologists, a reservoir with fracture is first and foremost a reservoir containing a structural discontinuities obtaining from a given paleostress history. While from the engineer's point of views, a reservoir with the fracture is foremost and first a reservoir which the flow affected with structural discontinuities. Naturally fractured reservoirs (NFRs) comprise fractures that naturally occurring. Actually, NFR exists in all reservoirs, and it has been very much debated in the literature [1]. The fluid flow modeling has been the most important part of the process to interpret the role of natural fractures in reservoir performance. Three commonly approaches have been used to model field scale flow of fluid in naturally fractured petroleum reservoirs, as shown in Fig. 1. The first model is a dual porosity (DP) with reservoir idealization, where a typical elementary representative volume (REV) of the rock of reservoir is assumed to contain a large number of equal size matrix blocks separated by interconnected fracture planes. The second model is a dual porosity/dual permeability (DP/DP) reservoir idealization, where, opposing to the first one, the matrix blocks be in touch with each other; therefore, there is matrix-to-matrix flow in addition to the matrix-to-fracture flow. The third model is the discrete fracture model (DFM), the most recent method, which depends on the three-dimensional spatial mapping of fracture planes to erect an interconnected network of fracture surfaces. Any 3D reservoir rock volume, surrounded by fractures is, therefore, a matrix block. It is very important to understand the fluid flow mechanism in a reservoirs with fracture. Barenblatt et al. were the first whose deal with this issue. They established the basic concepts of pseudo steady state fluid flow in naturally fractured rock for single phase depending on the dual porosity approach [2]. Warren and Root improved the Barenblatt et al. notion to including a shape factor, which was ignored in the earlier work [3]. Depending on the Warren and Root model, Kazemi et al. developed a 3D numerical simulator to simulate both the single and the two-phase fluid flow in fractured reservoirs [4]. Since that time, many studies described the dual porosity models of fluid flow through a naturally fractured reservoir [5-10]. Abdassah and Ershaghi explained that the DP model unable to predict the flow of fluid in the fractured reservoirs that contains vuggy formations. Meanwhile, they proposed a triple porosity model to deal with those reservoirs [11]. However, The multiple-continuum model discussed extensively by many authors [11-14]. Choi et al. proposed that by using dual porosity-dual permeability model and for high oil and water productivity, the more accurate result has been achieved when the Darcian and nonDarcian flow combined with each other, whereas all the previous issues subjected Darcy law in fracture and matrix zones. In their model, the fluid flow in Matrix has been subjected to Darcy law, while they used Forcheimer equation to explained the flowing of fluid through fractured zones [15]. Furthermore, the more credible behavioral for fluid flow in fractured reservoirs have been achieved by DFM method. It is so complex method, where the fluid flow in fractures and sub-fractures have to be considered [16-19].

In this study, the comprehensive workflow of using dual porosity-dual permeability approach has been adopted to show the fluid flow through the fractured porous media. Where the behaviour of flow in single and multi fractures with different orientations are investigated numerically using soft package CFX.

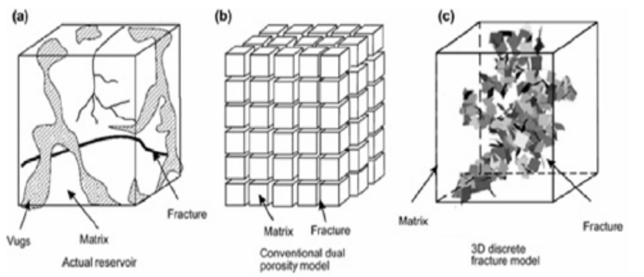

Figure 1: Fractured limestone cube; (a) actual porosity model,(b) sugar cube representation, and (c) discrete fracture model for a fractured reservoir [20].

2. Methodology

The most conventional method that simulated fractured rock is the Dual-Continuum Model, and it's widely used in the industry. It assumed that two contina exist in the same space, both fill the space completely without gaps and overlaps. One continuum represents the fractures and the other one represents the matrix [1]. Fig. 2 illustrates the fluid flow mechanism for both Dp and DP/DP models.

The model that utilized in this study is based on the following presumptions; Newtonian fluid (viscous), three dimensions, steady state flow, single phase flow, constant properties of the fluid (incompressible), homogeneous porous media, and Dual Porosity-Dual Permeability approach.

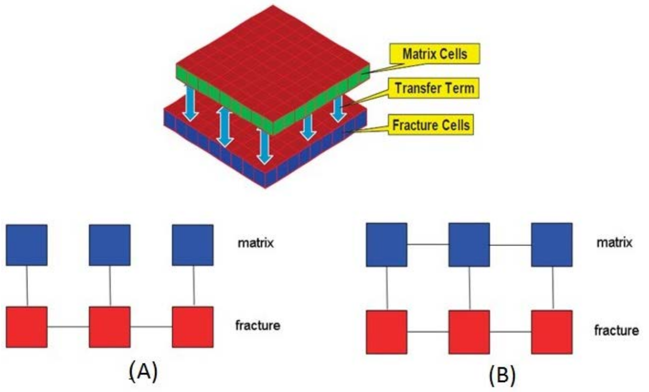

Figure 2: Illustration of a dual continuum model, A- The notion of Dual porosity Model B- The concept of Dual porosity -Dual permeability Model [1].

The governing equations of Dual Porosity-Dual Permeability model can be written for two domains as following [21]:

1- The governing equation for the solid deformation (matrix blocks) is given by:

$$\frac{\partial \emptyset^m s^m}{\partial t} + \nabla u^m = q^{f-m} + \psi^m \qquad (1)$$

$$u^m = -\frac{k_r^m k^m}{\mu}\{\nabla P^m - \rho g\} \qquad (2)$$

2- The governing equation for the fluid phase (Fractured zone) is given by:

$$\frac{\partial \emptyset^f s^f}{\partial t} + \nabla u^f = q^{m-f} + \psi^f \qquad (3)$$

$$u^f = -\frac{k_r^f k^f}{\mu}\{\nabla P^f - \rho g\} \qquad (4)$$

Where, the superscripts; f and m denote to the parameters which defined in fracture and matrix domains, respectively. The permeability of a single fracture and laminar fluid flow, can be given as [22]:

$$k = \frac{h^2}{12}\cos\theta \qquad (5)$$

And the Darcy's law of the flow of fluid through porous media can be written as :

$$Q = -\frac{1}{\mu} kA \frac{\nabla P}{L} \qquad (6)$$

The mean filter velocity in (6), is the Darcy velocity v_d which is related to the average pore velocity v_b by the relation [23]:

$$v_d = \emptyset\, v_p \qquad (7)$$

The productivity index (J) is defined as the ratio of the flow rate to the pressure drop, It can be given as:

$$J = \frac{Q}{\nabla P} \qquad (8)$$

The Computational Fluid Dynamic techniques (CFD) implemented in this study to represent the fluid flow in different types of fracture orientations. Fig. 3

illustrates the domains for all models that implemented in ANSYS program. In these models, the properties of the working fluid, the sandstone, and other important data are given in Table I.

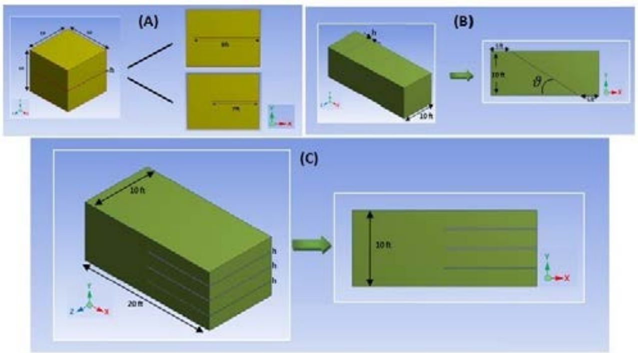

Figure 3: The model of fractures: (A) Single horizontal fracture with different length, (B) Single inclined fracture with different orientations, (C) Three horizontal fractures.

TABLE I

The data that used that for simulation of fluid flow in fractures

Paramteres	*BaseCase*
Fluid density	$0.8g/cm^3$
Fluid Viscosity	5centipoises
Fracture spacing(h)	0.1 ft
Fracture porosity	1
Matrix porosity	0.2
Matrix permeability	0.01 Darcy
Inlet pressure	3000 psi

3. Results and Discussions

Understanding fluid flow in fractured rocks according to dual porosity-dual permeability approach is one important target of this work. A mesh independence study for computational domains has been explained in Fig. 4, where the best mesh has been held at 3000000 nodes. Different orientations fractured is studied to visualized the fluid flow through the fractured reservoirs. The fluid used in this study is an incompressible fluid with a density equal to (0.8 g/cm^3), and viscosity equal to (5 cp). The contours of global pressure across the computational domains is explained in Fig. 5, where different types of fractures have been illustrated. The high permeability of a fracture gives a pressure propagation with high diffusivity along the fracture; however, because of a significant contrast between fracture permeability's and matrix, the matrix that surrounding by fractures has a delayed response to the changes of pressure comparing to that change of pressure in these fractured zones. The pressure contours for single horizontal fracture have been explained in Fig.(5: A and B), where the pressure distribution depends on the difference of fracture length. Fig.(5: C, D, E, and F) show the distribution of global pressure with different fracture orientations. Where a uniform distribution of pressure has been noted around the inclined fracture region along the studied area. As expectation, the fluid flow throughout the porous domain (Matrix) would be focused within the fractures. This is shown in Fig. 6, where the velocity streamlines are illustrated through the matrix and fractures. Due to the high permeability in fractures, the fluid flow will be high in fractured zones compared to matrix zones. As shown in Fig.(6; A and B), due to the high permeability of the fractures, the matrix zones contribute their fluid to the fractured zone. In Fig. (6; C, D, and E) where different orientations have been used, the fluid will flow from the first Matrix zone towards the fracture, which in turn will increase the flow rate within the Matrix area behind the fracture. Fig. (6; F), the matrix zones have been contributed their fluid to the three horizontal fractures, as exemplified in the figure. The velocity vectors through the fractured zones are visualized in Fig. 7. Fig.(7; A, and B) show the velocity vectors for horizontal fracture starting from 1 ft and 3ft of the beginning, respectively. The formation of two cells of different sizes can be seen inside of the space. The small cell is initially located while the other covers most of the space, this occurs because of the secondary flow effect and also due to the difference of pressure between the matrix and the flow inside the fracture zone. The secondary flow effect noted also, in three horizontal fractures as shown in Fig. (7; G). It's also cleared that the flow velocity is higher near the fractured region because of the small resistance of the flow and because of high pressure drop in the fracture region. From Fig. (7; C, D, and F) it can be seen the generation of vortices in the fracture zone when the fracture is inclined about 20^o, 30^o, and 45^o with horizontal. Actually, there are many reasons behind the vortices phenomena such as; the dual-permeability between the matrix domain and the fracture zones, the pressure change inside the fracture zone and in the interface zone between fracture and matrix, the fluid become free (without restriction) inside the fracture and the effect of gravity. In Fig. (7; F), where the angle of the fracture is increased to 70 degree with the horizon, is observed as the fluid flows from top to bottom without restriction due to the gravity force. The comparison between the productivity index of fractured and nonfractured reservoirs have been summarized in Table II. It can be concluded that the presence of fractures increases the productivity index of reservoirs. Good agreements are obtained when comparing the implementation of this program with the publisher where the study of single phase flow through different type of fractures have been studied [24]. Fig. 8, shows the comparison between our implementation and Sarkar et al. implementation for fluid velocity distribution at the middle of the fractured zone throughout the whole fracture aperture. Where, the aforementioned study used single fluid flow through a fractured rock in the parallel plate model, and they assumed that the fracture walls can be illustrated by two smooth, parallel plates, by an aperture (h=2mm) as separated.

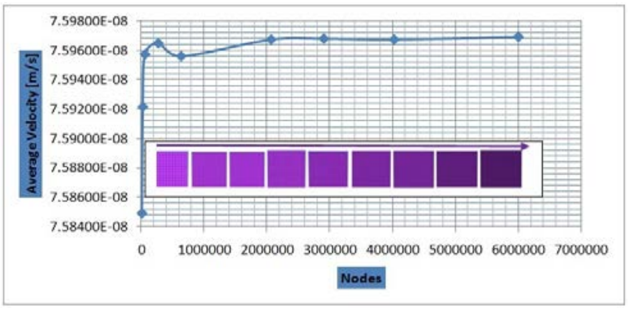

Figure 4: The Average velocity vs. different Nodes.

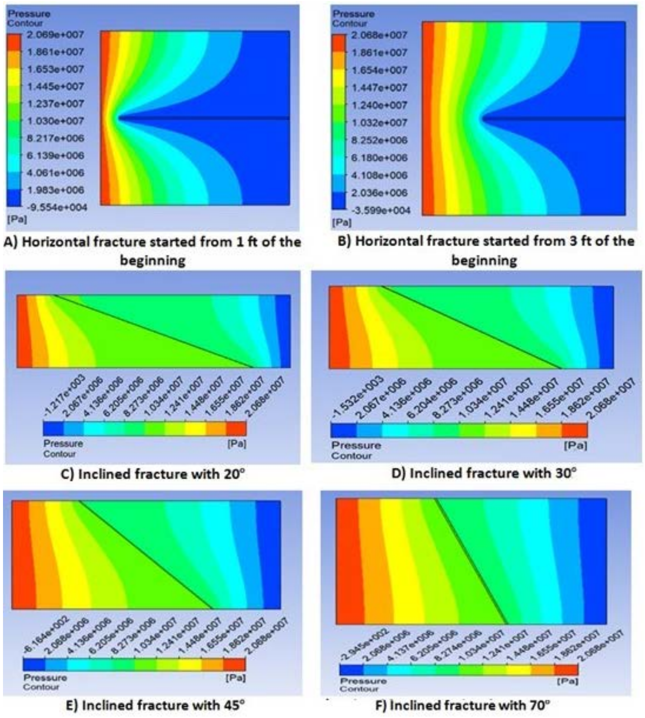

Figure 5: The Global pressure distribution throughout the domain with different fractures type.

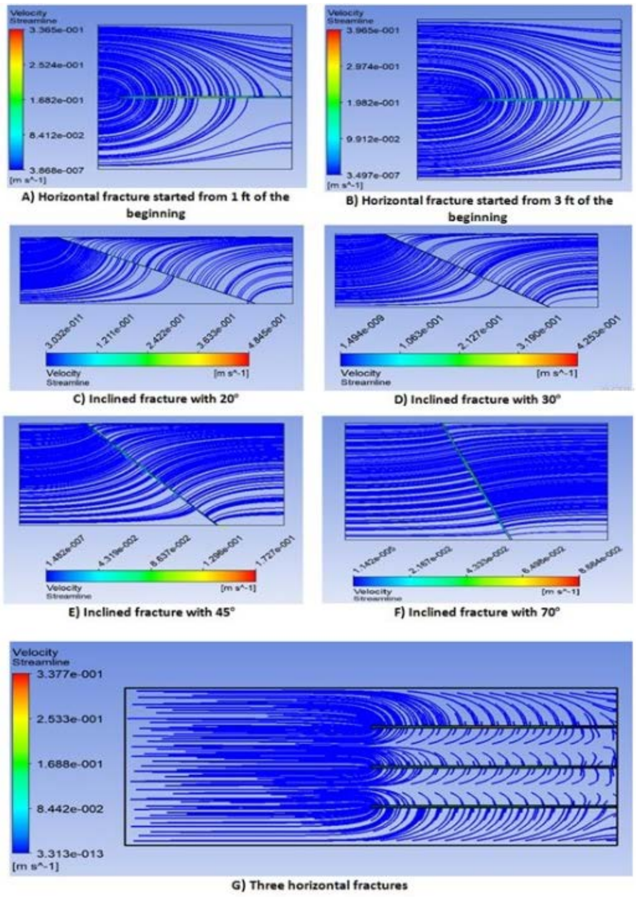

Figure 6: The velocity streamline throughout the domain with different fractures type.

TABLE II
Comparison the productivity index of the reservoirs with and without fractures

Case	J with Containing Fracture (BBL/Psi Day)	J without Containing Fracture (BBL/Psi Day)	The improvement percentage of the productivity index [%]
Case1: 9 ft horizontal fracture	0.993	0.578	71.8
Case2: 7 ft horizontal fracture	0.781	0.578	35.12
Case3: 20° inclined fracture	0.334	0.154	116.88
Case4: 30° inclined fracture	0.346	0.211	63.98
Case5: 45° inclined fracture	0.372	0.281	32.38
Case6: 70° inclined fracture	0.446	0.413	7.8
Case7: Multi horizontal fractures	0.880	0.282	212.06

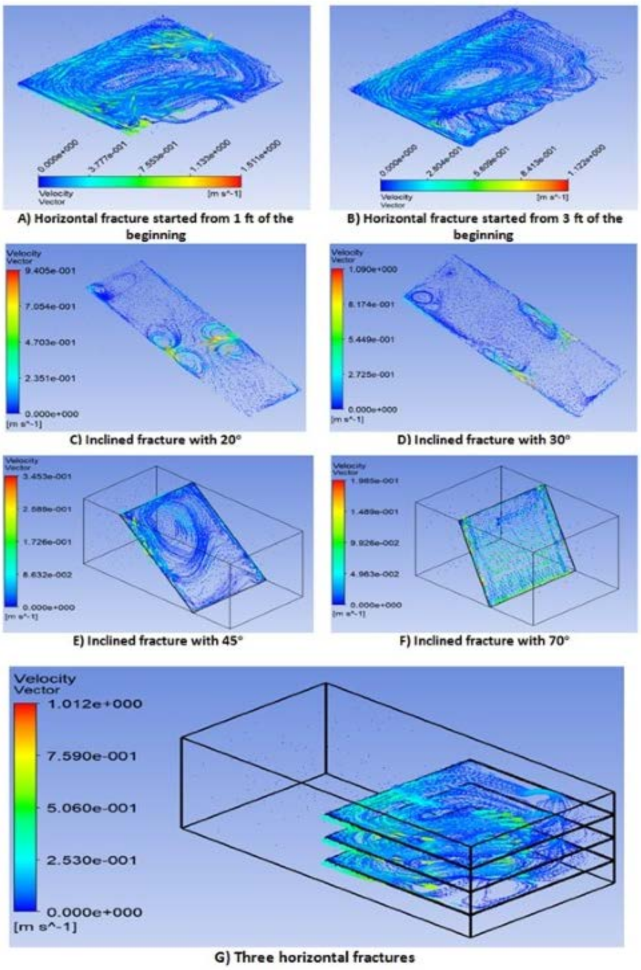

Figure 7: The velocity vectors throughout the fractures.

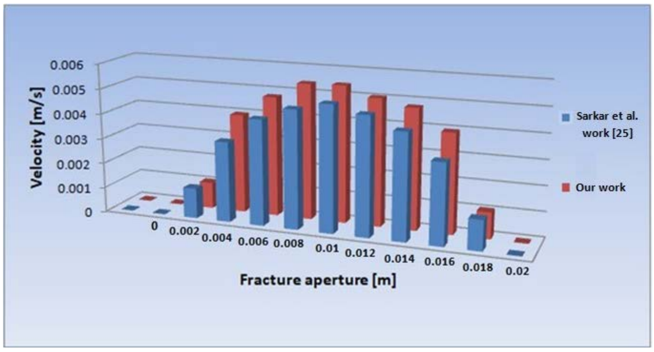

Figure 8: The velocity distribution along the fracture aperture at the middle of the domain

4. Conclusions

A realization has been conducted for improving the description of fluid flow through the fractured reservoirs. Where a three dimensional, steady state and single-phase flow in the homogeneous fractured reservoirs is implemented depending on dual porosity dual permeability model. This study concluded that the fractures with some characteristics can improve the fluid flow through the reservoir. In addition, the properties of fracture for instance; the size, the orientation, and the shape of the fracture have a significant effect of fluid flow throughout the reservoirs. All the aforementioned results are the gross end for evaluation that the fractures contribute to increasing the productivity index of the reservoirs. It also concluded that the pressure is distributed uniformly along the whole of the oblique fracture region. The percentage improvement of the productivity index for a single horizontal reaches to (71.8). Also, for inclined fracture, the angle (20^o) gives the maximum percentage improvement in productivity index (116.88) comparing with other angles (Horizontal, 30^o, 45^o, and 70^o).

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