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NUMERICAL SIMULATOR FOR NATURALLY FRACTURED RESERVOIRS USING PERMEABILITY TENSORS AND TIME DEPENDANT FACTORS

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ABSTRACT

Understanding the behavior of Naturally Fractured Reservoirs (NFR) has been one of the biggest challenges assumed by many researchers worldwide working in the field of reservoir characterization, modeling and simulation. Due to the high number of NFRs around the world and consequently the significant quantity of oil and gas contained within them, these reservoirs are a very attractive target for the oil industry. However, due to the degree of complexity involved in their modeling, they require a considerable investment of both time and money. Construction of a numerical simulation tool that implements two more recent technological concepts namely tensor permeability and time dependant form factors have a great impact when modeling more realistically the NFR performance. ***SIMYNF*** is able to characterize permeability in the three dimensions of the fractured system and the inter-porous flow present in matrix-fracture systems; based on finite differences for black oil reservoir with double porosity and/or double permeability, three phases, three dimensions, Darcy's flow and isothermic conditions. It is capable of modeling vertical, horizontal and deviated wells; simulate recovery mechanisms such as gas in solution, water thrust, gravity segregation and imbibition mechanisms.

KEYWORDS: Simulation, Naturally Fractured Reservoir, Permeability Tensor, Form Factor, NFR.

Resumen

El entendimiento del comportamiento de los yacimientos naturalmente fracturados (YNF) ha sido uno de los más grandes desafíos asumidos por varios investigadores a nivel mundial que trabajan en las áreas de caracterización, modelamiento y simulación de yacimientos. Debido al gran numero de YNFs a nivel mundial y consecuentemente la cantidad de aceite y gas contenidos dentro de ellos, estos yacimientos son un objetivo muy atractivo para la industria del petróleo. Sin embargo, debido al grado de complejidad involucrada en su modelamiento, se requiere una gran inversión en tiempo y dinero. La construcción de una herramienta de simulación numérica que tenga en cuenta el tensor de permeabilidad y el factor de forma dependiente del tiempo tiene un gran impacto cuando se desee modelar de manera más realista el desempeño de los YNF. SIMYNF es capaz de caracterizar la permeabilidad en tres dimensiones de sistemas fracturados y el flujo interporoso presente en el sistema matriz-fractura, basado en diferencias finitas para un yacimiento de aceite negro con doble porosidad y/o doble permeabilidad, de tres fases, tres dimensiones, flujo Darcy y condiciones isotérmicas. SIMYNF permite modelar pozos verticales, horizontales y desviados, simular mecanismos de recobro como gas en solución, empuje de agua, segregación gravitacional y mecanismos de imbibición

Palabras Clave: Simulación, yacimientos

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INTRODUCTION

The growing number of reservoirs classified as NFR, and high depletion rates of reservoir production considered as conventional at early stages, has driven the development of new characterization methodologies capable of identifying geologic and engineering parameters that describe the behavior, and allow the optimization of production with a lower degree of uncertainty. In this study a software simulation tool has been developed along with a new mathematical model for correcting time dependant form factors that describe the rate of inter-porous flow in matrix-fracture systems. Through this approach we improve the NFR modeling approach when considering non-lineal pressure gradients and matrix block saturation; as well as allowing the definition of reservoir fracture patterns. Furthermore, the concept of the permeability tensor models the flow of fluids in highly heterogeneous reservoirs with directional permeability zones obtaining results that show that this can be critical to predict in a more effective way the recovery factor and help to identify the optimal exploitation strategy.

THEORETICAL FRAMEWORK

The objectives of a reservoir simulator is to predict a reservoir's future performance based on its current status and previous performance (i.e. the history match), in order to determine exploitation methods and scenarios that allow increasing hydrocarbons final recovery at a minimum cost. A successful characterization exercise and its implementation within a numeric simulation model, will maximize hydrocarbons recovery by improving production strategies, minimizing drilling of unnecessary wells and improving future prediction of the reservoir's performance (Ordoñez et al, 2001).

SIMYNF, is a 3D, 3 phase black oil simulator, based on the finite difference method. It is built on the pillars of the BOAST Simulator, of public domain, distributed by the Department of Energy of the United States (DOE). It was developed to work with personal computers and Windows environment. It was created on C++ Builder 6.0, which provides a friendly dynamic interface for the user and the potential of the C++ programming language. The system of fractures added to the tool can be used to simulate production and injection of any combination of vertical, horizontal and deviated wells in a NFR represented by a model of double porosity and double permeability (Peñuela, 2002 and Gupta et al. 2000). The simulator solves a system of partial differential equations that describe the flow of multiphase fluids in the porous media (Peñuela, 2002).

SIMYNF simulates a Darcy 3-dimensional flow, under isothermic conditions; it assumes that fluids of the reservoir can be described by three phases with constant composition, whose properties are only a function of pressure. Among the oil/gas recovery mechanisms implemented within SIMYNF are fluid expansion displacement, gravity drainage and imbibition, using form constants factors to describe inter-porous flow rate. In addition, for 1D flow in oil-water systems, based on which it calculates the inter-porous flow rate. (Peñuela, 2002).

SIMYNF uses implicit formulation in pressure - explicit in saturation formulation (IMPES) to solve the differential equations systems. As time passes, the method finds the pressure distribution and then saturation distribution. To solve the system of pressure equations it uses the iterative solution technique LSOR (Line Successive Over-relaxation). This method requires less storage capacity and it is usually faster to solve problems of large magnitude. For the fractures pattern definition, it uses the permeability tensor concept that models flow fluids in highly heterogeneous reservoirs with directional permeability zones (Gupta et al., 2000). The simulator within its characteristics allows to perform bubble point follow up, material balance solutions stability check up, pressure maintenance, time lapsing automatic control, wells flow/pressure and secondary recovery operations restrictions.

The graphic tool interface is integrated by a launcher as the main module, from where all pertinent operations can be initiated in managing the data required for building the reservoir model, performing a simulation run, and subsequently visualizing results through two-dimensional and three-dimensional tabulated graphs.

Besides the simulation process module, the tool has pre and post data processing modules that facilitate managing and interpreting data. The pre-processor, called BUILDER NFR, is in charge of building the reservoir model by defining its dimensions, control parameters, and other information required to the start simulation. The runs execution is in charge of the NFR 2004 SIMULATOR processor. Display of results is carried out by the REPORT RESULTS post-processors in tabulated form, RESULTS GRAPH through two-dimensional graphs and RESULTS 3D in three-dimensional graphs.

The tool can be used through keywords like any other commercial simulator, allowing editing files in any word processor. The interface has relevant comments that help user recall types of data and units for each reservoir's parameter. The main advantage of this data input procedure is that it simplifies preparation, review, and data's visual confirmation, minimizing input errors.

SIMYNF can generate four types of reports during the simulation process, in order to have greater control over the simulation's parameters and results: 1) materials balance, which delivers original volumes on site (in standard conditions) for each phase; 2) Wells reports, are detailed at any time of the simulation's run and it is made up of production injection rates, accumulated volumes for each layer and each well; 3) Total Report, which contains concise information of injection and production performance including: average reservoir's pressure; oil, gas, water production rates and accumulated production; water and gas injection rates and cumulative injection; time lapsing and material balance for oil, water and gas. All this allows the user to rapidly review the reservoir behavior and determine if the model works correctly; 4) Variables distribution, it presents the distribution of pressure, saturation, and bubble point pressure for matrix and fracture systems at any time.

In addition as the simulation advances, ***SIMYNF*** shows a graph with oil and water flow production, and oil inter-porous flow rate between the matrix and the fractures. It also provides a report (during the run) of the variables: number of time steps, total time simulation, reservoir's average pressure, oil, water and gas rates, oil, water and gas accumulated production, GOR, WOR, water cut, inter-porous flow rates and number of iterations for convergence at the LSOR.

Fundamentals of the mathematical model

The Model assumes that the fractured system can be represented by two continuous systems that are superimposed on each other, with different porosity and permeability values. The matrix is made up of a porous rock intersected by a second porous medium defined as the fractured system. The equation of flow for phase p in the matrix system, it is given by:

$$\nabla.\left[\frac{\bar{k}_m k_{rpm}}{\mu_{pm} B_{pm}}\left(\nabla p_{pm} - \rho_{pm} g \nabla D\right)\right] = \frac{\partial}{\partial t}\left(\phi_m \frac{S_{pm}}{B_{pm}}\right) + \tilde{q}_p \tag{1}$$

Where $\tilde{q}_p$ is the inter-porous flow rate by unit of rock volume. The sub-index p represents the phase to which it is applied (water, gas, oil). In equation (1) gas solubility at the oil phase, is not indicated in search of simplicity. However, in this development the presence of gaseous phase was not considered. Only the water and oil phases were considered in implementing the flow correction factors and they were derived for interporous flow of these two phases.

It is assumed that the fractured system is made up of interconnected fractures that provide the most important flow paths for fluids production. This means that only the interconnected fractures are considered part of the fractured system and therefore, disconnected fractures are part of the matrix system (Peñuela, 2002). The flow equation in the fractured system for the phase p is:

$$\nabla.\left[\frac{\bar{k}_f k_{rpf}}{\mu_{pf} B_{pf}}\left(\nabla p_{pf} - \rho_{pf} g \nabla D\right)\right] = \frac{\partial}{\partial t}\left(\phi_f \frac{S_{pf}}{B_{pf}}\right) + \tilde{q}_p \tag{2}$$

An important characteristic of the fractured medium is its the permeability anisotropy. For this reason, the components of the permeability tensor should be used in equation (2), upon considering this variation (Gupta et al., 2000).

If the properties of the matrix, the fracture and the fluid are known, the system of equations given by the equations (1) and (2) can be solved along with the equations that define the matrix phases saturation and the fractured system, that should be equal to one:

$$\sum_p S_{pm} = 1 \tag{3}$$

$$\sum_p S_{pf} = 1 \tag{4}$$

Likewise, with the independent relationships of capillary pressure for the primary porosity, and for fractures as a function of saturation:

$$P_{cowm} = P_{om} - P_{wm} = f\left(S_{wm}\right) \tag{5}$$

$$P_{cgom} = P_{gm} - P_{om} = f\left(S_{gm}\right) \tag{6}$$

$$P_{cowf} = P_{of} - P_{wf} = f\left(S_{wf}\right) \tag{7}$$

$$P_{cgof} = P_{gf} - P_{of} = f\left(S_{gf}\right) \tag{8}$$

Equations (1) to (8) are a modification of traditional equations for simple porosity models, comparable to the Model proposed by Evans (1982) for naturally fractured reservoirs. The permeability tensor and the rate of inter porous flow was included, assuming initially constant and variable form factors, initially assuming constant and variable forms for flow in only one direction.

Implementation of the form factor

The implemented model is based on a matrix block being flooded by water through a fracture to which it is in contact. The rate of inter porous oil flow is given by the sum of the oil produced through the area that has not been exposed to water, and the area where the imbibing process is occurring. In general, the total oil rate is given by:

$$q_o = q_o\big|_{1p} + q_o\big|_{2p} \tag{9}$$

Where, sub-indexes 1p and 2p refer to the mono-phase and two-phase regions, respectively. The oil produced in region 1p is mainly due to viscous forces stated through the pressure gradient, while the oil in region 2p is the result of capillary forces due to the saturation gradient. The equation obtained is:

$$q_o = 2F_c\big|_{1p} A_o k_m \frac{k_{ro}}{\mu_o}\bigg|_{1p} \frac{\overline{p}_{om} - p_{of}}{L} + 2F_c\big|_{2p} A_w k_m \frac{k_{ro}}{\mu_o}\bigg|_{2p} \frac{\overline{p}_{om} - p_{of}}{L} \tag{10}$$

Where effective flow areas are calculated as lineal functions of the saturation phase in the fracture, as follows:

$$A_o = S_{of} A \tag{11}$$

$$A_w = S_{wf} A \tag{12}$$

Where: Ao+Aw is the interfacial total area matrix/fracture, A.

Likewise, the inter-porous flow rate for water is calculated as the result of the interaction of capillary and viscous forces. However, it is assumed that the forces act simultaneously, initially prevailing capillary forces. Once the capillary pressures are equal in the matrix and the fracture, the viscous forces control the inter-porous flow of water. This can be expressed as follows:

$$q_w = 2F_c\big|_{2p} A_w k_m \frac{k_{rw}}{\mu_w}\bigg|_{2p} \frac{\overline{p}_{wm} - p_{wf}}{L} \tag{13}$$

The effective area for water to flow is given by equation (12).

The correction factor for inter porous flow F_c, is similar to the form factor used in calculating porous for the double porosity model. In this paper the factor obtained by Peñuela was implemented (2002), which can be represented as follows:

$$F_c = 2.47\left(1 + \frac{0.0133}{t_D}\right)^{0.5} \tag{14}$$

$$t_D = \frac{k_m}{\phi_m \mu c_t L^2} t \tag{15}$$

Permeability tensor

To appropriately model the inherent anisotropy to the fractured system, a tensor of permeabilities should be used. Peñuela (2000) developed a method where the orientation of the fracture is used to build the permeability tensor (Ordoñez et al., 2001). A mathematical model of the parallel plates was used (Snow, 1969), to derive an equation that can be evaluated if appropriate seismic data, well logs and pressure tests are available (Gupta, 2000).

Tool application

Example 1. To evaluate the importance of the permeability tensor in simulation, a case study was implemented based upon available information from the literature (see **Table 1**), the PVT data and the fluid and rock properties, with the exception of capillary pressure data, were taken from Thomas et al. (1983). Capillary pressure data was taken from Firoozabadi and Thomas (1990). This example was run under two scenarios: homogeneous and heterogeneous. The last one takes into account the permeability tensor. The Model is an areal reservoir with 4 water injection wells located on each corner of a Cartesian grid and a producing well in the center of the same grid, as shown in **Figure 1**.

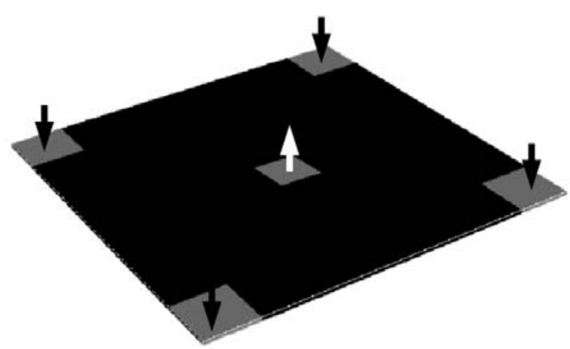


Fig. 1. Example 1 Grid .

Table 1. Basic Data – Example 1

Number of cells in the x direction	15	Kxx (md)	20.875
Number of cells in the y direction	15	Kyy (md)	20.875
Number of cells in the z direction	1	Kzz (md)	0
Dx (meters)	70,71	Kxy (md)	0
Dy (meters)	70,71	Kxz (md)	0
Dz (meters)	15,24	Kyz (md)	0
f_m	0,29	Pressure at the WOC (Kilopascal)	41368
K_m (md)	1	Depth of the WOC (pies)	685,8
ff	0,01	Injection rate (m³/d)	127,18
W_f (meters)	0,015	Production rate (bpd)	397,44
Lf (meters)	1,524		

For the heterogeneous case, which takes into account the permeability tensor, the values shown **Table 2** were used; the remaining data was not modified.

Table 2. Permeability tensor

Kxx (md)	20	Kxy (md)	3
Kyy (md)	9.4	Kxz (md)	0
Kzz (md)	0	Kyz (md)	0

Example 2. In order to evaluate the importance of the time depending form factor use, we took the same case as in example 1, adjusting the grid to one dimension, since this parameter only applies to one-dimensional models. The model has ten cells in the X direction, with a well that produces 900 bpd of oil, located at cell (1,1) and another, through which 1000 barrels of water per day are being injected, is located in cell (10,1) (See **figure 2**). The modified data is as follows (Table 3):

Figure 2. Grid used in Example 2

Table 3. Basic Data of Example 2

Number of cells in the x direction	10	Kxx (md)	90
Number of cells in the y direction	1	Kyy (md)	90
Number of cells in the z direction	1	Kzz (md)	90
Dx (meters)	60,96	Kxy (md)	0
Dy (meters)	304,8	Kxz (md)	0
Dz (meters)	15,24	Kyz (md)	0
f_m	0,1	Pressure at the WOC (KiloPascal)	41762
K_m (md)	0,3	Depth of the WOC (meters)	685,8
ff (fraction)	0,01	Injection Rate (m³/d)	158,97
W_f (meters)	0,0152	Production rate (m³/d)	143,08
Lf (meters)	3,048		

Analysis of results

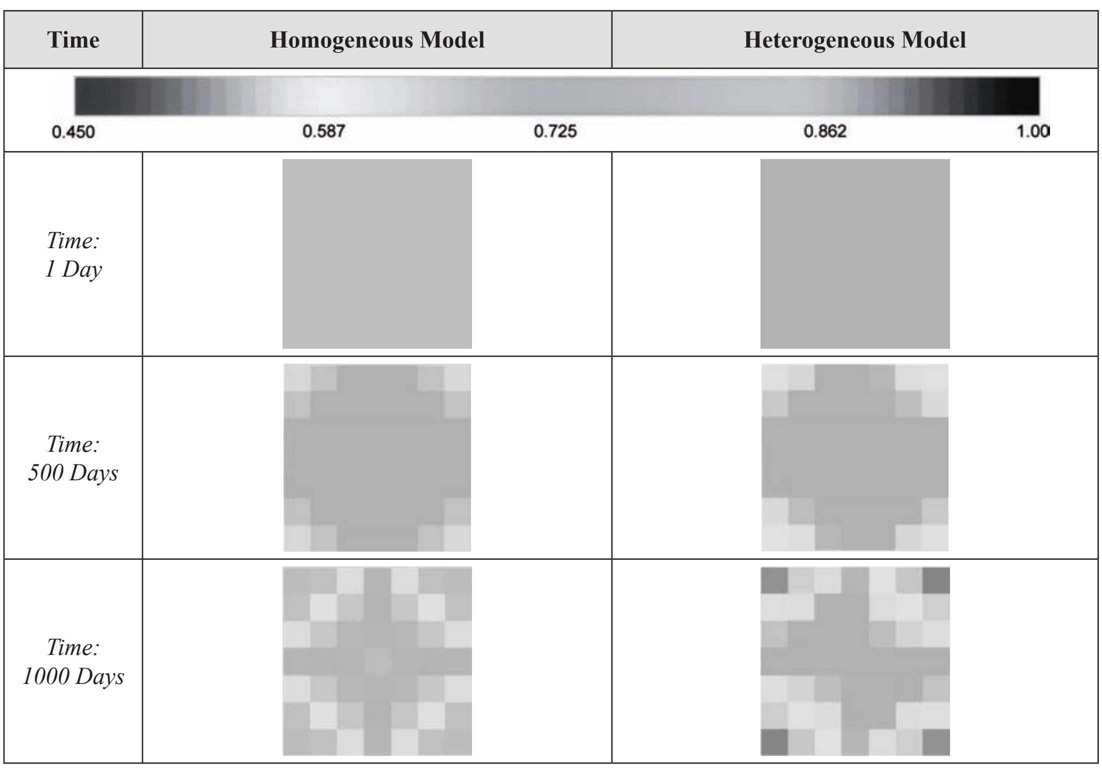
Results of the simulation for example 1 are shown in Figures 4-7. According to the results obtained from these simulations, it appears that inclusion of the fractured system permeability tensor significantly influences the simulation process of a NFR, since through this parameter you can have a better approach to the porous medium heterogeneous characteristics. For this example, by taking into account that the tensor provides higher oil saturation values at the matrix system as it is observed in **Figure 3** that leads to lower recovery factors as shown in **Figure 6**.

For the fractured system it is observed that water and oil saturations change faster than in the matrix system, due to fractures that make up channels through which fluids flow easily. The oil saturation value varies from 100% to 0% during the simulation period in neighboring blocks to the injection wells, since the fracture contributed with all the oil it contained, being assisted by the injection process, as shown in **Figure 5**. At the end of simulation process, lower oil saturation was obtained in the heterogeneous system in cells near to the producing well due to oil contained in the fractures and the oil contributed by the matrix, toward the same cells, flowing more easily.

Upon analyzing the overall reservoir (matrix system + fractured system) set out in this example, it can be concluded that lower recoveries are obtained when using the permeability tensor, as shown in **Figures 6 and 7**. This result is essential in selecting exploitation strategies of naturally fractured reservoirs, and it reaffirms the importance of modeling them using a permeability tensor where the natural fracture system creates a significant proportion of cross flow permeability (e.f. Kxy). In the event that the fracture system comprises two orthogonal sets aligned to the simulation grid, there is a reduced necessity to represent the fracture permeability as a full tensor, with simple directional permeability values being adequate.

In example 2, we show the influence of using the time dependant factor in calculating the matrix-fracture inter-porous flow, on the hydrocarbon recovery contained in the reservoir. In this case's simulation, it was observed that in short-time periods (smaller than 100 days), whether or not you take into account the time dependant from factor, it provides similar results as those observed in **Figure 5**, **Figures 8, and Figure 9,** since the water injection process has not affected the producing well's drainage area. For times periods longer than 100 days, the use of the time dependant form factor provides production rates different to those obtained when using a constant form factor; in this particular case larger production rates were obtained and consequently a greater recovery factor with the use of the time dependant form factor; this variation is mainly due to capillary forces. The time dependant factor of inter-porous flow provides a better matrix-fracture flow model because it is a function of variables that control the imbibition process. Thus, the importance of using the time dependant form factor in simulation of NFR reservoirs, since it significantly affects (positively or negatively) hydrocarbon recovery, from the start of the short time modeling process, which influences appropriate planning of production strategies of naturally fractured reservoirs in order to maximize their recovery.

Fig 3. Oil saturation in the matrix **(**Example 1)



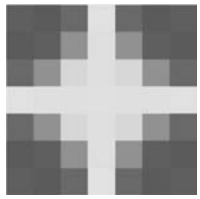
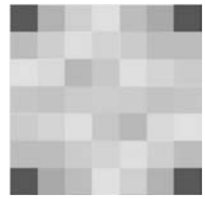
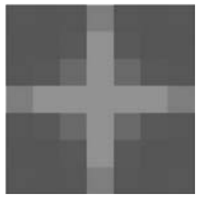
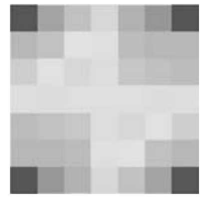
Time: *1500 Days*		
Time: *1800 Days*		

Fig 4. Oil saturation in the fracture system (Example 1)

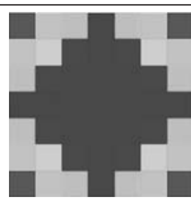
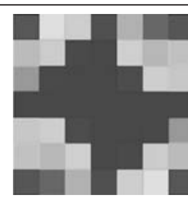
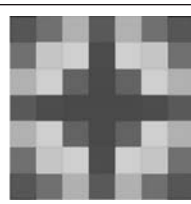
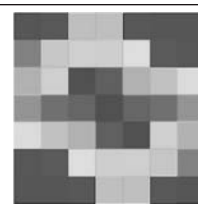
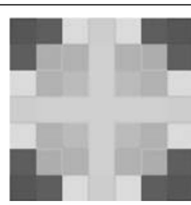
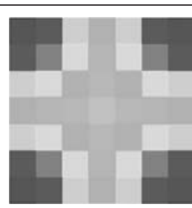
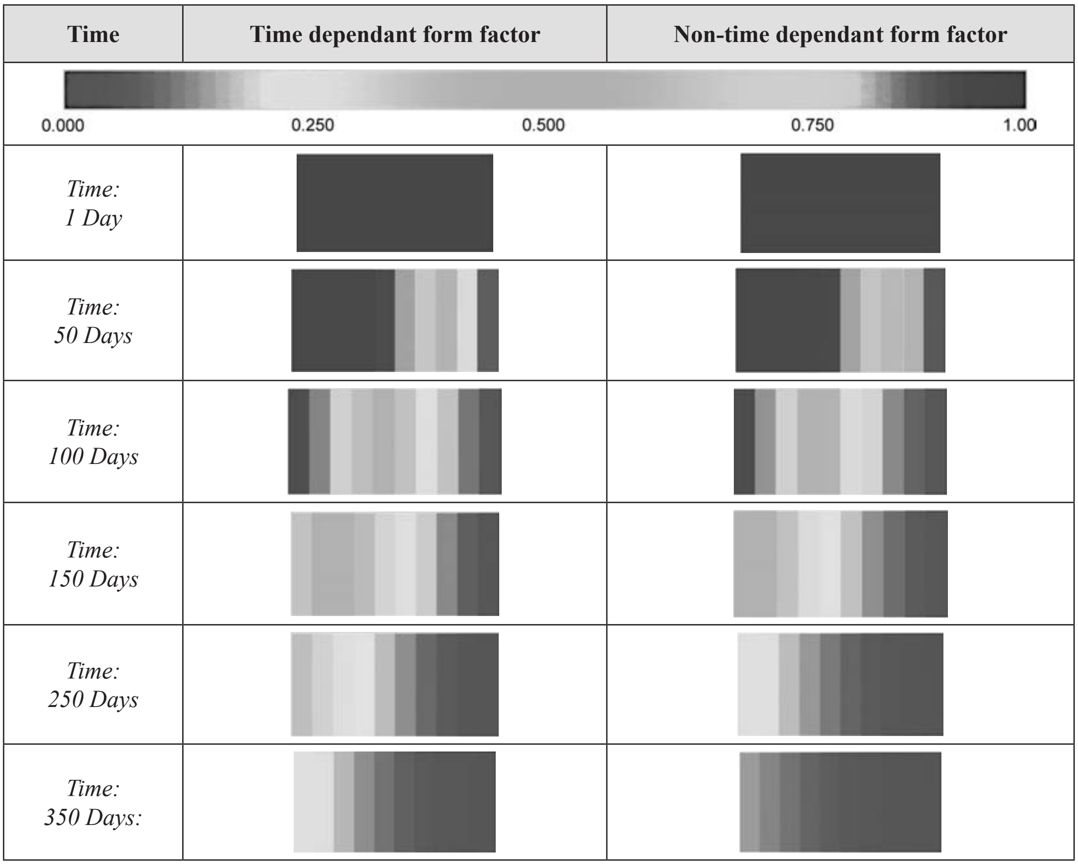
Time	Homogeneous Model	Heterogeneous Model
		
Time: *1 Day*		
Time: *500 Days*		
Time: *1000 Days*		
Time: *1500 Days*		
Time: *1800 Days*		

Fig 5. Oil saturation in the fracture system



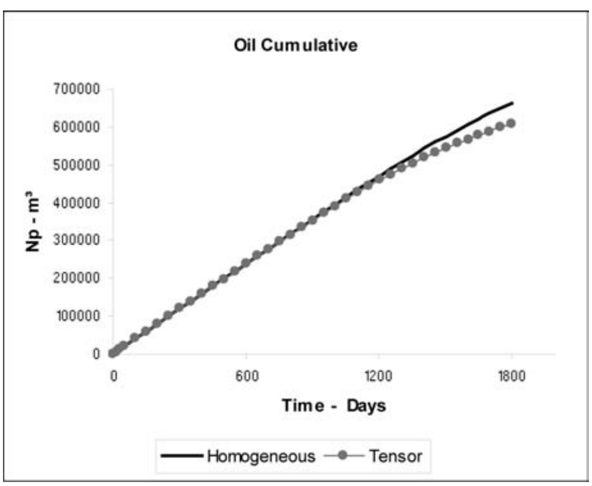


Fig 6 – Oil Production vs. Time

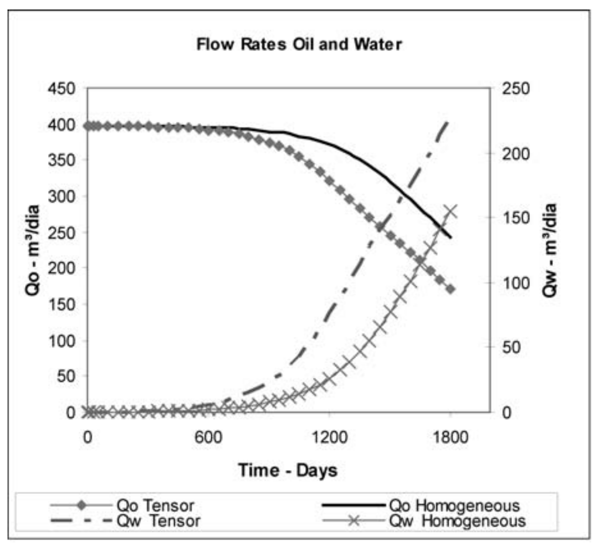


Fig 7 - Oil and water flow rates vs. Time

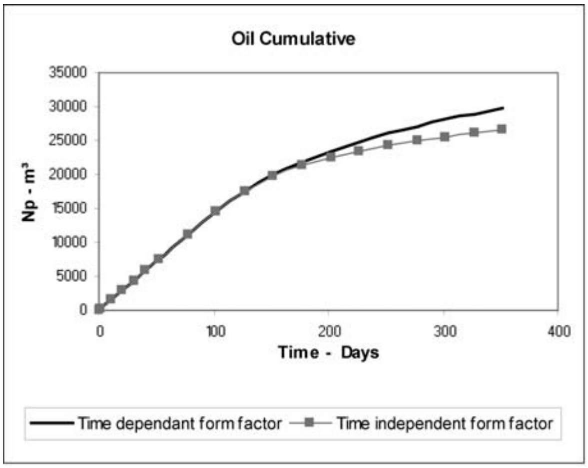


Fig 8 – Oil Production vs. Time

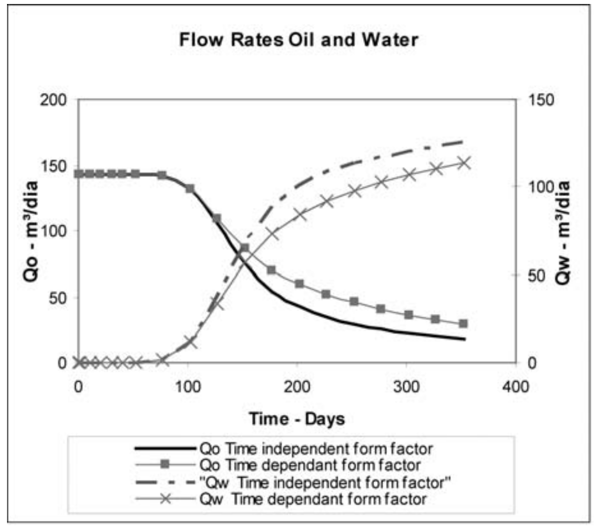


Fig 9 - Oil and water flow rates vs. Time

NOMENCLATURE

∇ = operator differential n-able
k = permeability
k_r = relative permeability
$\mathbf{k}$ = permeability tensor
μ = viscosity
B = volumetric factor
p = pressure
ρ = flow density
D = reservoir depth
ϕ = porosity
S = saturation
q = flow rate
f = fracture density
F_c = correction factor of inter-porous flow
A = effective flow total area
P_{cow} = oil-water capillary pressure oil-water
P_{cgo} = gas-oil capillary pressure
L = fracture spacing
t_D = Nondimensional time
c_t = total compressibility
t = time

Subindexes

o = oil phase
w = water phase
g = gas phase
m = matrix
p = phase
f = fracture

CONCLUSIONS

Inclusion of anisotropy in the naturally fractured reservoirs simulation through the use of the permeability tensor, provides a more realistic model of the reservoir since it better represents the permeability structure created by the natural fracture system.

The use of a time dependant form factor to model the matrix-fracture inter-porous flow provided more realistic value estimates of production rates, in the case studied the values obtained were more conservative.

It is important to include the time dependant form factor, since production rates are affected starting at short-time periods after the simulation begins.

In the naturally fractured reservoirs simulation you should keep in mind the permeability tensor and the time dependant inter-porous flow form factor, may help you to obtain more realistic answers. Of course accurately constraining these tensor values is best achieved thorough characterization supported by discrete fracture modeling techniques.

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