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Paper Title: **Modeling and Simulation of Gas and Water Flow in Tight Fractured Porous Media**

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ABSTRACT

The considered porous media in this paper belong to gas reservoirs characterized by a low permeability matrix and high permeability fractured system. The mathematical model differentiates between two flow regions, one representing the discrete matrix and the other representing the continuous fracture network. Fracture is characterized by a much smaller volume than the pores (low storage). The model utilization was demonstrated by solving a three-dimensional isothermal transient two-phase flow of gas and water in a low permeability porous media which has been developed from the general conservation laws of mass and momentum. Darcy's and nondarcy's laws were incorporated into the equations to couple them by a fluid transfer term which depends on the potential difference between the two specified regions. The specific problem to which the numerical solution was applied assumes a single horizontal fracture perpendicular to the flow direction in a quite small geometry. Accounted for are fluid incompressibility and immiscibility, the effect of capillary pressure and relative permeability. A numerical solution was obtained using the modified CFX-Flow3D code. The simulation was applied to some obtained results in the laboratory experiments and predicted two-phase flow behavior. Calculated two-phase flow rates reflect the sensitivity of fluid flow to gas and liquid permeability in tight porous media. Also the results indicated that the multilayer reservoir provides a better estimate of post-fracture performance compared to a more conventional, single-layer reservoir description.

KEYWORDS: Modeling; Simulation; Tight Reservoir; Fracture; Two-Phase Flow.

Introduction

Richardson et al. [1] provided the overall summary of multiphase flow in porous media research accomplished prior to 1973. West et al. [2] were among the first who studied one-dimensional radial and linear flow in a gas/oil system, including the role of dissolved gas but neglecting gravity and capillary pressure. Later, the studies were extended to two- or three-dimensional cases. The majority of numerical simulations were performed with black oil models that assume that the reservoir hydrocarbons consist of only two components: oil and gas.

There are only a few studies in the literature regarding the theoretical analysis or simulation of single- and two-phase flow. Newberg et al. [3], and Arastoopour et al. [4, 5] were among the first who developed a mathematical model to describe single- and two-phase flow in a low permeability porous medium. Chen [6] modified the Black Oil Applied Simulation Tool (BOAST) computer code for two-phase flow of gas and water through low permeability tight sand reservoirs. In his modification, fluid velocities were assumed to follow Darcy's law. Later, Wang [7] modified Chen's model by incorporating the non-Darcy equation for both gas and liquid phases. Pakdel [8] developed a computer program to study a one-dimensional flow of nitrogen and water in low permeability porous media. She found that her model is sensitive to variations in volume fraction, flow rate, pressure, rock physical characteristics, and overburden pressure.

This paper presents the application of general model equations to two-phase flow through low permeability porous media, where the momentum transfer between the fluids and rock matrix is represented by Darcy and non-Darcy equations for the water and gas phases, respectively, Khlaifat [9 and 10]. Also the capillary pressure forces were incorporated into the model, and the gravity effect was neglected. The imbibition, drainage, and two-phase flow of gas and liquid through low permeability tight sand porous media were simulated using the CFX-F3D program. The calculated flow behavior agrees reasonably well with experimental two-phase flow behavior.

Mathematical Model and Constitutive Equations

A three-dimensional, isothermal, two-phase flow through porous media model was developed to study the behavior of homogeneous and rigid tight porous media. In order to simulate this phenomenon, we had to modify the multi-fluid model of CFX-F3D to account for capillary pressure effect. The experimental values of capillary pressure as a function of concentration of each phase were included in the code. Darcy and non-Darcy expressions for water and gas phases were used as interfacial forces between the phases and porous media.

Continuity equation:

$$\frac{\partial}{\partial t}(\phi S_\alpha \rho_\alpha) + \nabla \cdot (\phi S_\alpha \rho_\alpha \mathbf{U}_\alpha) = 0 \tag{1}$$

Momentum equation:

$$\frac{\partial}{\partial t}(\phi S_\alpha \rho_\alpha \mathbf{U}_\alpha) + \nabla \cdot (\phi S_\alpha (\rho_\alpha \mathbf{U}_\alpha \otimes \mathbf{U}_\alpha - \boldsymbol{\tau}_\alpha) = \phi S_\alpha (\mathbf{B}_{r\alpha} - \nabla P_\alpha) \tag{2}$$

where, α denotes phase (water or gas), ϕ is porosity, ρ_α density, S_α saturation, $\mathbf{U}_\alpha$ velocity vector, $\boldsymbol{\tau}_\alpha$ viscous stress tensor, $\mathbf{B}_{r\alpha}$ interfacial momentum transfer between the rock matrix and phase.

The viscous stress tensor may be expressed as:

$$\boldsymbol{\tau}_\alpha = \mu_\alpha (\nabla \mathbf{U}_\alpha + (\nabla \mathbf{U}_\alpha)^T) \tag{3}$$

and equation of state as:

$$\rho_\alpha = \rho_\alpha (T_\alpha, P_\alpha) \tag{4}$$

in addition:

$$S_w + S_g = 1 \tag{5}$$

The liquid-rock interfacial force was expressed in the form of Darcy's equation:

$$\mathbf{B}_{rw} = \frac{\mu_w \varepsilon_w}{k_w} \mathbf{U}_w \tag{6}$$

and the gas-rock interfacial force was expressed in the following form:

$$\mathbf{B}_{rg} = \frac{\mu_g \varepsilon_g}{k_g} \mathbf{U}_g + \beta_g \rho_g \varepsilon_g (\mathbf{U}_g)^2 \tag{7}$$

where, ε_α is the volume fraction $(\varepsilon_\alpha = \phi S_\alpha)$, k_α effective permeability, and β_α is a coefficient accounting for local flow non-uniformities, and usually is a function of pore size, pore size distribution, and pore structures.

Equations (1, 2, 4, and 5) represent eleven equations and twelve unknowns $\rho_g, \rho_w, U_g, V_g, W_g, U_w, V_w, W_w, P_g, P_w, S_g$ and S_w. We need one more equation to close the system. This equation is given by capillary pressure (P_c):

$$P_c = P_g - P_w \tag{8}$$

In our study, the capillary pressure (in Pascal) was defined experimentally CER [11] as a function of wetting fluid (water) saturation as shown in the following expression:

$$P_c = 97480 (S_w)^{-2.2658} \tag{9}$$

Geometry and Topology

Computational domain is a collection of blocks that are connected together across inter-block boundaries. The underlying grid structure of each block is contained in a region which is topologically a cuboid. This means that each block may be considered conceptually as a rectangular array of "bed strings," which may be distorted to fit the boundary of a desired physical domain. This distortion defines a "mapping" from "computational space," with coordinates given by the integer indices (I,J,K) of cell vertices, to the desired region of "physical space". The only restriction to the mapping is that cells do not overlap.

We created the required physical domain for our simulation using Mesh-Build. The created geometry has the same dimensions of the sample used in our experimental studies as shown in Figure 1. The geometry has a length of 0.0905 m, a diameter of 0.0381 m, and a grid of 10x10x30.

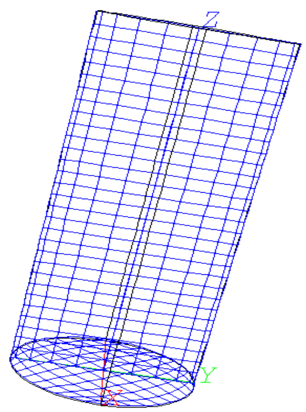

Figure 1: Schematic Representation of Porous Core Sample with Grid Definition

Boundary Conditions

At the wall the standard no slip conditions were used. We used the inflow and outflow pressure boundaries because only pressure was known experimentally. For pressure boundary, pressure is specified and Neumann conditions are applied to the velocities, $\partial \mathbf{U} / \partial n = 0$, where n is the normal direction to the inlet or outlet cells.

Results and Discussion

The mathematical model described above was solved using CFX-F3D for two kinds of geometry: the geometry shown in Figure 1, and a geometry consisting of three blocks representing fractured porous media. In the single geometry (Figure 1) we have two pressure patches, one is the inlet and the other is outlet. The boundary conditions used for this geometry are tabulated in Table 1. The effects of capillary pressure and interfacial momentum transfer were incorporated into the code through the subroutine USRBF (user body force). Different cases of two-phase flow simulations have been conducted for both physical domains with the conditions stated in Table 1. One example of the simulation describes when the two-phase flow simulation was performed for the case when our tight sand initially was saturated with 99 % water $(S_{w-initially} = 0.99,\ t = 0)$. The inlet saturation for both phases was set to be the same $(S_w = S_g = 0.5,\ t > 0)$. The saturation and velocity vector profiles versus the length of the core sample are shown in Figure 2.

Table 1 Characteristics and Boundary Conditions of the Simulations

Three Dimensions

Gravity Effect is Neglected

Isothermal, Laminar, Transient, and Incompressible Flow

Volume Porosity $\phi = 0.07$

Inlet and outlet Pressures $P_{inl} = 4.237\,\mathrm{MPa}$, $P_{out} = 0.1\,\mathrm{MPa}$

Resistance Constants. In order to find these constants we have used the single-phase experimental values of permeability at an overburden pressure of 3000 psig (20.70 MPa) $R_w = 1.547E + 14\,\mathrm{Pa.s.m}^{-2}$, $R_g = 6.785E + 11\,\mathrm{Pa.s.m}^{-2}$

Coefficient β, also was found from single-gas phase experimental data at the same operating conditions $\beta = 1.14E + 14\,\mathrm{m}^{-1}$

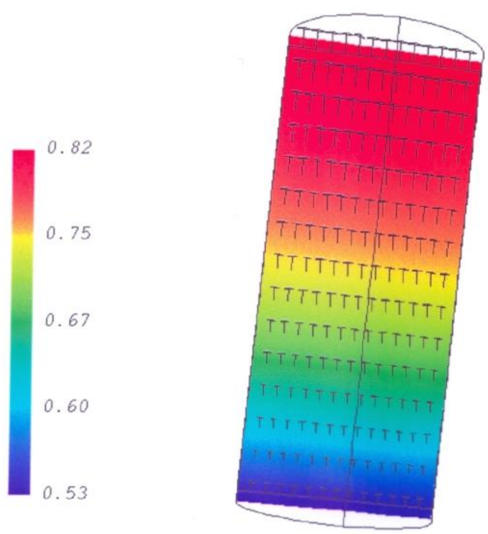

Figure 2: Water Phase Saturation and Velocity Vector Profiles in Tight Gas Sand after 13.89 hrs

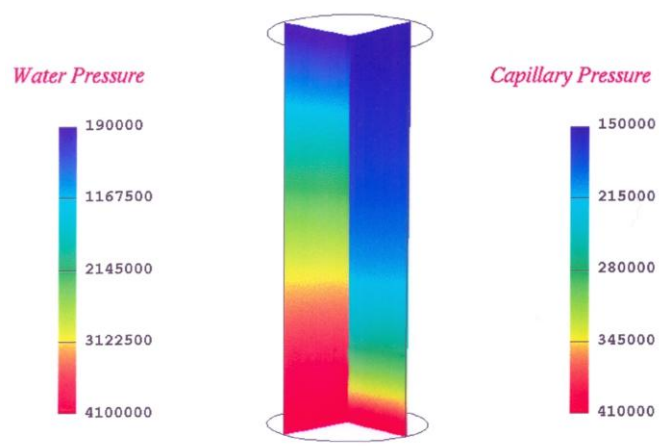

Figure 3: Water Phase Pressure and Capillary Pressure Profiles in Tight Gas Sand after 13.89 hrs

From Figure 2 it can be seen that, as time goes on, water phase saturation is decreased while the gas phase saturation is increased until it reached the inlet condition. Figure 3 shows both capillary and liquid pressure distributions. It is obvious that at steady state the capillary pressure becomes constant and the liquid pressure profile becomes linear. All other simulation scenarios for both geometries and parametric studies will be presented at the conference.

Conclusions

The transient, three-dimensional two-phase flow through tight formations of porous media was studied. The modified CFX-F3D code considered the Darcy equation for the liquid phase and the non-Darcy equation for the gas phase as interfacial momentum transfer terms between the solid matrix and each of the fluids. For flow through low permeability porous media, capillary force has significant effects on the flow patterns of both the gas and water phases.

Two-phase flow, drainage, and imbibition simulations gave reasonable results for flow through homogeneous low permeability porous media.

Performing the simulation of two-phase flow through a porous medium consisting of several porous blocks with different permeabilities and porosities showed that the production is higher when the fluid flows first through a low permeability medium followed by a high permeability medium. This means hydraulic fracturing around the production well significantly enhances gas production from tight sand formations.

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