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Three dimensional pressure transient behavior study in stress sensitive reservoirs

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ABSTRACT

Stress sensitivity is a phenomenon that affects reservoir rock properties, such as permeability and therefore changes the well pressure transient behavior. This paper aims to study these behaviors in stress sensitive reservoirs and evaluate the pressure loss in such reservoirs during the process of hydrocarbon production. A power model is used to correlate the changes in permeability with pore pressure. A novel semi-implicit three-dimensional finite element method has been employed to numerically solve the flow problem. The numerical results have been validated by analytical results obtained in a non-sensitive reservoir. Pressure drawdown test for different scenarios has been studied. The presented numerical method could contribute to better understanding the stress-sensitivity phenomenon and its effect on reservoir performance.

1. Introduction

Detailed information about the reservoir behavior and performance is a crucial necessity for efficient reservoir management. Well pressure transient study (WPTS) is an effective technique employed to gather this information. Reservoir rock properties and fluid characteristics can be obtained by WPTS. Moreover, this study can determine reservoir domain and well completion efficiency. Therefore, WPTS helps to have an efficient reservoir management. WPT is under the influence of the stress sensitivity phenomenon. The sensitivity of reservoir rock properties to a change in stress field is called stress sensitivity. This phenomenon affects reservoir rock skeleton and changes the properties of rock such as permeability. Geological parameters change reservoir rock skeleton. Strata properties, water content and reservoir depth are among these geological parameters. Depletion throughout the reservoir lifetime can also change the rock skeleton.

Numerous researchers have investigated the effects of stress sensitivity on pressure transient behavior. Pedrosa (1986) developed an analytical solution based on perturbation technique for stress sensitive problem (Pedrosa, 1986). Kilmer et al. (1987) presented a log-log relation for permeability changes with net overburden pressure in gas reservoirs (Kilmer et al., 1987). Sayers (1990) studied the permeability tensor anisotropy due to stress in fractured rocks (Sayers, 1990). Drawdown and buildup solutions for stress sensitive reservoirs have been obtained using the concept of permeability modulus by Zhang and Ambastha (1994). Permeability modulus means that permeability is an exponential function of pressure (Zhang and Ambastha, 1994). In addition, the effects of permeability reduction on pressure buildup solution has been studied by Ambastha and Zhang, 1996 (Ambastha and Zhang, 1996). A skin factor relation has been recommended by Jelmert and Selseng (1997) for stress sensitive reservoirs (Jelmert and Selseng, 1997). Chin et al. (2000) developed a coupled geo-mechanics and single-phase flow model to calculate the impact of changes in rock properties such as porosity and permeability on well analysis in stress sensitive reservoirs (Chin et al., 2000). Well test curve of stress sensitive reservoirs is under the influence of permeability and compressibility alternation according to Pinzon et al. (2001). Scholes et al. (2007) proposed a model for the effects of compressive stress on permeability anisotropy in porous media (Scholes et al., 2007). Chen and Li (2008) provided a mathematical model for production prediction based on reservoir skeleton deformation (Chen and Li, 2008). The relation between permeability and geological stress has been presented by Wang et al. (2010) in fractured reservoirs (Wang et al., 2010). Zhang et al. (2010) simulated well testing for stress sensitive reservoirs with heterogeneity and non-uniform thickness (Zhang et al., 2010). A method for analyzing transient linear flow in tight oil and gas reservoirs with stress sensitive permeability and multi-phase flow has been developed by Qanbari and Clarkson, (2012, 2014). High resolution three-dimensional simulations have been presented by Shaoul et al., 2015 in a tight gas reservoir based on stress sensitive permeability data obtained from core testing (Shaoul et al., 2015). Zhao et al. (2014) simulated the flow behavior of

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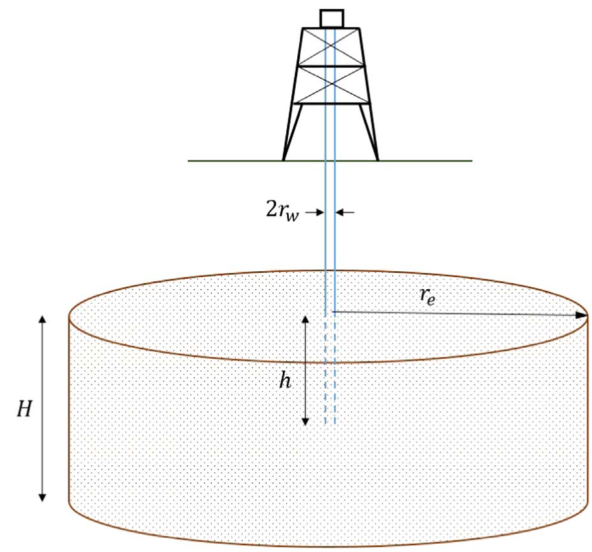

Fig. 1. Schematic diagram of the reservoir geometry.

a horizontal well using the perturbation technique (Zhao et al., 2014, 2016).

Almost all previous studies have utilized an exponential model to correlate the permeability changes with pore pressure. New experimental researches demonstrate that a power model better describes stress sensitive behavior than the classical exponential model (Ren and Guo, 2014). Stress-sensitivity models correlate rock permeability with the reservoir pore pressure. These models are based on many experimental measurements from different rock types. Curve-fitting techniques are used to implement these experimental data into the mathematical equation which govern the flow inside the reservoir rock. One of the widely used curve-fitting techniques is the exponential model.

In the present work WPT behavior in three-dimensional stress sensitive reservoirs using a power model and the Galerkin variational method with finite element discretization is simulated. It should be mentioned that poroelastic effects are not considered in this work and experimental relations are used to model the effect of stress sensitivity on rock skeleton. This work aims to study the effects of stress-sensitivity on rock permeability reduction and the wellbore pressure in different scenarios. Pressure drawdown test under several situations, such as different degrees of stress sensitivity and well penetration ratios is investigated. All of the reservoir rock properties except permeability are assumed to remain unchanged. Moreover, it is assumed that fluid properties are independent of stress and remain constant.

This paper is organized as follows: First, the mathematical formulation of the problem and a description of the numerical method is presented. Results and discussion section consists of four different cases. The first case is a WPT analysis without the effects of formation damage, partial well completion, wellbore storage and stress sensitivity, and is carried out in order to evaluate the accuracy of the method. In the second case, the influence of skin factor and wellbore storage on WPT is investigated. In the third case, the effects of stress sensitivity is added to the second case. And lastly, the combined effects of stress sensitivity and partial well completion on WPT is studied in the fourth case.

2. Mathematical Formulation

In the following subsections, the assumptions used in solving the flow problem are described. Moreover, mathematical formulae governing the problem are established. The numerical method and computational grid used to solve the flow equations are also presented.

2.1. Assumptions

The reservoir is initially a homogeneous and isotropic cylinder and is bounded by impermeable walls on all outer boundaries. The fluid is single-phase and slightly compressible and fluid flow obeys Darcy's equation. The producing well is a one dimensional line which is situated at the center of the reservoir. Production rate is held constant and wellbore storage and skin effects are taken into account. Gravitational effects are neglected. It is assumed that all of the reservoir properties except permeability, are independent of stress and remain constant. Although, it should be mentioned that properties such as porosity and compressibility have some degree of dependency on stress, but their changes over the pressure range are small compared to that of permeability and therefore it is reasonable to treat them as constants. A schematic diagram of the reservoir geometry is shown in Fig. 1.

2.2. Governing Equations

Flow equation for single-phase slightly compressible fluid in porous media is given by Eq. (1).

$$\nabla.\left(\frac{k}{\mu}\nabla P\right) = \phi c\frac{\partial P}{\partial t}+q$$

$$c = c_r + c_f \tag{1}$$

Where P is the pore pressure, k is the reservoir rock permeability, ϕ is the porosity, c_f is the fluid compressibility, c_r is the rock compressibility, c is the total compressibility and q is the volumetric flow rate. In Eq. (1), permeability is a function of pore pressure. Several models have been developed to express permeability in terms of pore pressure. In this work, the relation between pressure and permeability as proposed by Ren et al. (2014) is modelled using a power model as shown in Eq. (2).

$$\frac{k}{k_i} = \left(\frac{P_{ob} - P}{P_{ob} - P_i}\right)^{-\gamma} \tag{2}$$

Where P_{ob} is the overburden pressure and γ is the dimensionless stress sensitivity coefficient, which depends on reservoir rock type. The stress sensitivity coefficient can be determined by experimental core testing.

The wellbore pressure decreases due to formation damage. Eq. (3) is used to model the effect of formation damage on the wellbore pressure.

$$P_w = P'_w - \Delta P_s \tag{3}$$

$$\Delta P_s = \frac{q_{sf}B\mu}{kH}S = q_{sf}s$$

Where P'_w is the wellbore pressure without formation damage, P_w is the corrected wellbore pressure, ΔP_s is the pressure loss due to formation damage, S is the skin factor, s is the skin factor per unit volumetric flow rate and H is the reservoir thickness.

Whenever there is a change of production rate, part of the production due to the wellbore fluid volume changes. This is known as the wellbore storage effect and is modelled by Eq. (4).

$$q_{sf} = q + \frac{C_s}{B}\frac{dP_w}{dt} \tag{4}$$

Where C_S is the wellbore storage coefficient, q is the production rate, q_{sf} is the reservoir flow rate and B is the formation volume factor. Combining Eqs. (1), (3) and (4), fluid flow equation for wellbore nodes becomes:

$$\frac{1}{\mu}\nabla.\left\{k\nabla\left[P_w+s\left(q_{sf} + \frac{C_s}{B}\frac{dP_w}{dt}\right)\right]\right\} = \phi c\frac{\partial P_w}{\partial t} + \left(q + \frac{C_s}{B}\frac{dP_w}{dt}\right) \tag{5}$$

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