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Effect of flow mechanism with multi-nonlinearity on production of shale gas

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ABSTRACT

Different from oil reservoirs, variations of gas properties (such as viscosity, Z-factor and gas compressibility) under different pressures is strongly nonlinear and non-Darcy effect is significant in fractures due to high rate. Shale gas reservoirs are extremely tight with nanopores, where Darcy's law breaks down and the flow behavior is significantly influenced by pore scale and pressure. 20%–80% of the shale gas in place (in-situ) is adsorbed to organic matters and the desorption is a nonlinear process varying with pressure. Furthermore, hydraulic fractures and natural fractures close gradually, as the production proceeds, resulting in a non-linear relationship between permeability and pressure. However, the multi-nonlinear flow mechanism, as well as its effect on gas production, in the process of shale gas development is always overlooked by both laboratories and industrial analyses.

Based on the five-region model, finite difference method is applied to get numerical solution in this paper. Afterwards, the effect of nonlinear mechanism on production is analyzed, according to which, the enhanced ultimate recovery (EUR) schemes are proposed. The results show that the effects of compressibility, multi-scale flow, stress sensitivity and non-Darcy flow in fractures on production are significant during early stage and should be considered in well testing model. For middle and late production stages, the effects of compressibility, multi-scale flow, stress sensitivity in natural fractures should be considered in the Rate Transient Analysis (RTA) model and long-term production prediction model. The negative effect of stress sensitivity and non-Darcy flow can be reduced or mitigated by optimizing schedule and controlling early pressure drawdown. Furthermore, some nonlinear factors can be used positively by refracturing, which reduces formation pressure and consequently leading to the increase of gas compressibility, desorption compressibility and apparent permeability.

1. Introduction

Based on a large number of mathematical models built to obtain type curves, unsteady well testing and RTA were used to calculate formation properties as well as production prediction. As shale gas wells typically exhibit a long period of linear flow, Bello and Wattenbarger (2008; 2010a; 2010b) built a dual linear model with convergence skin. Based on their work, Ozkan et al. (2011), Brohi et al. (2011) and Xu et al. (2013) extended the model considering the supply of unfractured region. Furthermore, Stalgorova and Mattar (2013) presented a general five-region model with isolated SRV (Stimulated reservoir volume).

Source function model is used to solve the problem of simple fractures and interconnected complex fracture network and offers a semi-analytical solution. Guo et al. (2012), Zhao et al. (2013), Wang (2014) presented Green function models assuming dual porosity in infinite reservoir and linear flow in fracture. Zhao et al. (2014) , Zhou et al. (2014) took SRV into consideration and extended the previous work to composite reservoir or interconnected fractures, making it possible to simulate flow in complex fracture network.

Although there have been many ways to get analytical/semi-analytical solutions of mathematical models, nonlinearity was neglected in most of them. Gas properties change significantly under different conditions, among which nonlinear viscosity and Z-factor are generally considered with the concept of pseudo-pressure. However, the nonlinearity of gas compressibility has not

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been well solved yet, on the contrary, gas compressibility under original formation conditions is adopted in the current mathematical models. The effect of nonlinearity on production is significant and thus results in huge errors (Zhang et al., 2014). Agarwal (1979) presented pseudo-time to involve nonlinearity of μc product with average pressure. However, it's difficult to choose an average pressure appropriately and this may needs tedious iteration (Tabatabaie et al., 2013; Behmanesh et al., 2014). Based on Boltzmann transformation, Kale and Mattar (1980), Kabir and Hasan (1986) used perturbation theory to treat nonlinearity of μc product, however, it could only be applied to a vertical well in an infinite formation. Mireles and Blasingame (2003) considered nonlinear compressibility by building convolution, simplifying μc product as a parameter changes with average pressure and transforming nonlinear compressibility from real space to Laplace space. The method is practical in theory but actually depends on average pressure changing with time, therefore it's not as simple as pseudo-time but has similar problems. Barreto et al. (2012a; 2012b) treated nonlinear terms as nonlinear source and solved it by one iteration using Green function. However, the calculation of these complex integral under infinite space is still a time consuming task. It is still difficult to treat nonlinearity of μc product for analytical solution, but it may have great effect on production and should not be neglected.

Shale gas reservoir is tight with nanopores, in which gas flow can not be well characterized with conventional Darcy flow or Fick diffusion. Although gas flow in nanopores can be described by molecular simulation, Monte Carlo and Lattice Boltzmann method, the combination of the existing models and commercial simulators is still difficult and time consuming, which makes equivalent apparent permeability more practical. Ertekin et al. (1986), Beskok and Karniadakis (1999), Javadpour et al. (2007), Javadpour (2009), Civan (2010), Civan et al. (2011), Darabi et al. (2012), Shi et al. (2014) presented corrected models using apparent permeability, which deviates from Darcy flow as Knudsen number increases resulting from decreasing pressure and pore diameter. Liu et al. (2014, 2015) analyzed gas flow considering diffusion and Klinkenberg effects coupled with deformation and adsorption. In addition, shale gas productivity decreases along with the decreasing fracture permeability (especially natural fractures) on account of stress sensitivity. Apparent permeability and stress sensitive fracture permeability are functions of pressure, and their nonlinearity can both be represented by pressure dependent permeability. Ozkan et al. (2011) and Apaydin (2012) integrated nonlinear terms into a newly defined pseudo-pressure, but tedious iterations are required and the definition of pseudo-pressure on the interface of matrix and fracture is mismatched. Aybar et al. (2014) solved the problem caused by stress sensitivity of natural fracture permeability, however, the average pressure solution depends on finite difference method, which itself can actually solve the problem of stress sensitivity and no iteration is required. Eshkalak et al. (2014) investigated the effect of multiple nonlinear parameters with finite difference method, but he had not thought over all of the nonlinear parameters, especially nonlinear compressibility.

In this paper, the effect of multi-nonlinearity is considered and finite difference solution is applied, based on Five-Region Model (Stalgorova and Mattar, 2013), to investigate the effect of multi-nonlinearity on shale gas production. Multi-nonlinearity mechanism in production process is firstly introduced and treated as a parameter varying with pressure. Furthermore, nonlinearity is coupled into Five-Region Model for numerical solution with finite difference method, which is then validated with analytical solution. Sensitivity analysis and EUR optimization are conducted considering multi-nonlinearity mechanism. This paper is aimed at building a simplified mathematical model to investigate the effect of multi-nonlinearity on production, to predict long-term shale gas production more efficiently and to give suggestions for enhanced ultimate recovery.

2. Flow mechanism with multi-nonlinearity

2.1. Viscosity and Z-factors

Gas property varies under different conditions. For instance, gas viscosity increases along with pressure and as pressure rises, Z-factors will first decrease and then increase. The numerical approximate method presented by Lee et al. (1966) and Dranchuk and Abou-Kassem (1975) is used to calculate gas parameters in this paper, as shown in Fig. 1(a). Pseudopressure, which involves the nonlinearity of viscosity as well as the Z-factors, is in one-to-one correspondence with the pressure. And it is easy to convert between pressure and pseudopressure, as shown in Fig. 1(b). The pseudopressure can be expressed as follows:

$$m(p) = 2\int_0^p \frac{p}{\mu Z} dp \tag{1}$$

2.2. Gas compressibility and desorption compressibility

Like viscosity and Z-factors, gas compressibility changed a lot with different pressure, which is a significant factor neglected by most of the models or simulator. The compressibility of real gas is defined by Eq. (2), and it is calculated with numerical approximate method presented by Lee et al. (1966) and Dranchuk and Abou-Kassem (1975). As shown in Fig. 2, the compressibility increases as the pressure drops, the change is significant when it comes to low pressure conditions.

$$C_g = \frac{1}{\rho}\left(\frac{\partial \rho}{\partial p}\right)_T = \frac{1}{p} - \frac{1}{Z(p)}\left(\frac{dZ(p)}{dp}\right)_T \tag{2}$$

In shale reservoir, organic material could absorb a large amount of methane, which constitutes 20–80% of the geological reserves (Sang et al., 2014). Therefore, it has great influence, especially in late period of development, on the production of shale gas. The Langmuir adsorption is adopted here (Eq. (3)), and it is believed to be the easiest and the most commonly used model for characterization of the absorption and desorption of shale gas.

$$V = \frac{V_L P}{P + P_L} \tag{3}$$

The Langmuir adsorption is usually considered and added to total compressibility (Bumb and McKee, 1988). Desorption compressibility is defined as follows:

$$C_d = \frac{T P_{sc} Z V_L P_L}{T_{sc}\phi_m (P_L + P)^2 P} \tag{4}$$

As the pressure changes, the nonlinearity of gas compressibility as well as the desorption compressibility is remarkable and should not be neglected (Fig. 2): under low pressure conditions, both of the two compressibility increase extremely as pressure drops. It would be very inappropriate for some models to take only the desorption compressibility into consideration while treat gas compressibility as constant. As a matter of fact, the effect of a changing gas compressibility may outweigh the desorption compressibility.

According to Eq. (3), the difference of adsorption under different pressure is considered to be the cumulative desorption, so the contribution of desorbed gas can be evaluated. Based on the