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A semi-analytical model to evaluate productivity of shale gas wells with complex fracture networks

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ABSTRACT

With the increasing of clean energy demands and the maturing of shale gas extraction technology, multiple fractured horizontal well (MFHW) has become the most key technology for shale gas development. After hydraulic fracturing, fracture networks, which consist of natural fractures, hydraulic fractures and secondary fractures, are formed around the wellbore. Compared to conventional gas reservoirs, shale gas reservoirs are characterized by the complex fracture networks and gas adsorptions in shale matrix. Therefore, it is essential to propose a new productivity evaluation method for shale gas wells to handle these characteristics.

In this paper, to account for special characteristics of MFHW, a complex fracture model for shale gas reservoirs is established. With the new method, shale reservoirs are depicted by De Swaan dual porosity model, where the secondary fractures and hydraulic fractures are characterized by discrete units. Therefore, together with micro-seismic data, fracture networks can be exactly described using this new model. With a well-depicted facture network, Green function and superposition method are then adopted to model the flow in the reservoir, and finite difference method is used to solve the equations of one-dimensional flow in fracture system. Besides, to deal with the complex flow in the fracture intersection, star-delta transformation is applied Finally, the equations of reservoir and fracture system, the solution in Laplace domain is obtained, which can then be transferred to real domain using the Stehfest algorithm.

Comparisons were made between the results of the proposed model and that of a numerical model accomplished by commercial simulator Eclipse for a specific case to verify the accuracy of the model. Results show that the semi-analytical method is more efficient than numerical method by reducing the computing time without losing accuracy. Moreover, the semi-analytical productivity evaluation method can describe fracture networks more exactly. Then, a field case from Sichuan Basin of China is applied in the analysis. The results shows that desorption gas takes up 10%-30% of the total production in this case. Besides, the effects of storage capacity ratio and inter-porosity flow coefficient on type curves were analyzed based on the production decline curves. In addition, pressure profiles of different production times are obtained by the superposition of pressure potential.

1. Introduction

In recent decades, shale gas reservoirs around the world have been effectively developed and utilized due to the successful application of MFHWs (Mayerhofer et al., 2008; Cippolla, 2009; Guo et al., 2015; Williams-Kovacs and Clarkson, 2016).

The classical shale gas production evaluation model is the Partition Method, where the shale gas reservoir is divided into different flow regions based on the liner flow assumption. Bello and Wattenbarger (2010) established a dual porosity production model for fractured shale gas wells. The effect of near-wellbore confluence was considered, and the yield equation was corrected by employing skin factor. On the basis of Bello's liner flow model (Bello and Wattenbarger, 2010), Alahmadi (2010) established a triple-porosity model which consists of artificial fractures, natural fractures and matrix, assuming that artificial fractures are symmetrical wings, and natural fractures and artificial fractures are perpendicular to each other. Then, Tivayanonda et al. (2012) simplified Alahmadi (2010)'s model, based on the assumption that the fracture is infinite diversion. Ozkan et al. (2011) proposed a mathematical model of the tri-linear flow. In their model, the reservoir is divided into two different regions: the outer zone and the inner zone. The inner reservoir is a dual medium, while the outer reservoir is a single medium. Based on the tri-linear flow model, Brohi et al. (2011) obtained the type curves by considering a constant outer boundary pressure. Xu et al.

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(2013) further improved the mathematical model of Brohi et al. (2011), by considering the existence of abundant natural fractures in the outer zone, which is also assumed to be a dual medium. Stalgorova and Mattar (2013) regarded the SRV to be isolated, and established a more generalized model, which divides the control volume of a single fracturing stage into five regions.

Although the partitioned model can calculate the productivity conveniently, it cannot reflect the shale gas flow behavior under complex fracture networks. The inversion of micro seismic data can be used to obtain the fracture morphology in shale gas reservoirs (Wu et al., 2015; Song et al., 2015), which makes shale gas production forecasts more accurately. Guo et al. (2012), (Zhao et al., 2013, 2014), and Wang (2014) assumed that the fractures are perpendicular to the wellbore and with infinite conductivity. Besides, the adsorption and desorption characteristics of shale gas are accounted for by Langmuir isotherm. By applying point source function and mass conservation method, the seepage flow model of a fractured dual-porosity reservoir is also established, where the production decline curves are produced by numerical inversion. Zhou et al. (2014) divided the fractures into several nodes, and solve the production capacity which couples the flow in the matrix and fracture, based on the point-source solution in real space. Jia et al. (2015, 2017) dealt with complex fractures by applying star-delta transform method. With this method, the flow function in the fractures is calculated by finite difference method, while the flow function in the matrix is calculated by source function.

For the seismic data acquisition in the complex fracture network of MFHWs, there is still an unsolved problem on how to evaluate the productivity and to make production performance forecasts more accurately. Therefore, it is very important to establish a mathematic model to evaluate productivity of shale gas wells with complex fracture networks.

2. Mathematical model

2.1. Physical description and assumption

After hydraulic fracturing, complex hydraulic fractures and secondary fractures will be formed in shale gas reservoirs. According to the characteristics of fractured shale reservoir, it can be simplified into a dual-porosity system composed of matrix and primary fractures, as well as a discrete fracture system composed of secondary fractures and hydraulic fractures. As shown in Fig. 1, the only difference between the secondary fractures and the hydraulic fractures is conductivity, so their treatment is consistent with artificial fractures.

The basic assumptions of the model are as follows:

(1) The reservoir is assumed to be horizontal, infinite, homogeneous, equal thickness, and with the upper and lower boundary closed;
(2) The primary fractures and the matrix are simplified to the De Swaan dual-porosity model. Gas is assumed to flow from the matrix to the primary fractures and then to the discrete fracture system;
(3) The effects of gas desorption and slippage are considered, the gas is assumed to be single phase and unstable flow in shale matrix and fracture;
(4) The secondary fractures and the artificial fractures are with finite conductivity and interfere with each other; gas flow in the secondary fractures and hydraulic fractures is assumed to be linear flow, and the fractures' tips are handled with closed boundaries.

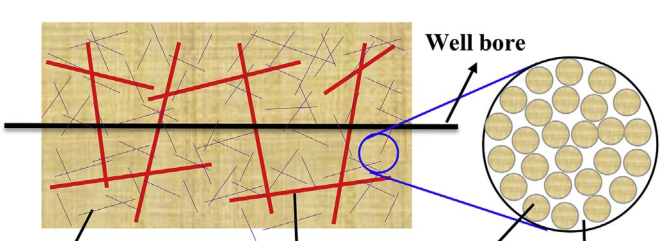

Fig. 1. The schematic of the physical model.

Therefore, the flow of shale gas from the reservoir to the wellbore is transient flow, and the fluid flow can be divided into two parts: the flow from the reservoir to the secondary fractures and hydraulic fractures, and the flow within the fracture system. Pressure transient type curves under constant production rate condition and the production decline curves under constant pressure condition can be obtained by coupling the pressure and flow of the two parts on the fracture surface. At the same time, the pressure field diagram near the well region can be plotted by superposition principle.

2.2. Mathematic model in reservoir

Adsorption gas accounts for 20 to 80 percent of the geological reserves of shale gas reservoirs, which affects the composition of production, especially in the later production stages (Sang et al., 2014). The Langmuir adsorption model is the most common and simple model for characterizing adsorption and desorption of shale gas. The Langmuir adsorption capacity is usually added to the system total compressibility in the form of desorption compressibility (Zhang et al., 2015), as shown in Eq. (1).

$$C_d = \frac{Tp_{sc}zV_Lp_L}{T_{sc}\phi_m(p_L + p)^2 p} \tag{1}$$

The total compressibility can be expressed as Eq. (2):

$$C_t = C_g + C_R + C_d \tag{2}$$

As shown in Eq. (3), pseudo-pressure are introduced to characterize the changes in gas viscosity and deviation factor with pressure:

$$m = 2\int_0^p \frac{p}{\mu(p)z(p)}dp \tag{3}$$

In this paper, we use the method of Javapour (Javadpour, 2009), Swami and Settari (Zhang et al., 2015) to characterize the slippage flow and the Knudsen diffusion of shale gas during matrix infiltration.

$$k_{app} = 10^{-9}C_g D\mu + Fk_D \tag{4}$$

$$F = 1 + \left(\frac{8\pi RT}{M}\right)^{0.5}\frac{\mu \times 10^{-3}}{p_{avg} \times 10^6 r_n}\left(\frac{2}{\alpha} - 1\right) \tag{5}$$

Defining the pseudo-time is as follows:

$$t_a = \int_0^t \frac{\mu_{gi}C_{ti}^*}{\mu_g(p)C_t^*(p)}dt \tag{6}$$

Therefore, considering desorption, slip flow and diffusion, a mathematical model of seepage in the matrix in the form of polar coordinate is established:

$$\frac{\partial^2 m_m}{\partial r^2} + \frac{2}{r}\frac{\partial m_m}{\partial r} = \frac{\phi_m\mu_{gi}C_{mti}^*}{3.6 \times 10^{-3}k_m}\frac{\partial m_m}{\partial t_a} \tag{7}$$

$$\left.\frac{\partial m_m}{\partial r}\right|_{r=0} = 0 \tag{8}$$

$$m_m(r, t)|_{r=r_1} = initial \tag{9}$$

$$q = -\frac{3}{r_1}\frac{Mk_m}{RT}\left.\frac{\partial m_m}{\partial r}\right|_{r=r_1} \tag{10}$$

When shale gas flows into the primary fractures from the matrix, the seepage control equation is: