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A semi-analytical mathematical model for predicting well performance of a multistage hydraulically fractured horizontal well in naturally fractured tight sandstone gas reservoir

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ABSTRACT

Multiple fractured horizontal well (MFHW) is one of the key technologies to exploit low permeability reservoirs. The accuracy of productivity evaluation after fracturing not only affects the effectiveness of fracturing treatment, but also affects the optimum design of parameters in horizontal wells. This paper is the first investigation into the semi-analytical mathematical modeling for gas productivity calculation of multi-staged horizontal wells in fractured tight sandstone gas reservoirs that emphatically considers the impact of flow in fracture network (natural fracture system). Herein, a production forecast model of complex hydraulic fractures was created where the impact of nature fractures was simulated, and a semi-analytical solution was obtained by using Gaussian elimination method. As extension of historical work, this novel model could be applicable to more actual conditions such as fractures at arbitrary angles and unequal, asymmetric fractures.

In the subsequent work, a numerical simulation of a simple conceptual model has been conducted, which validated the accuracy of this novel model. Then a real case application was successfully implemented. The modeling calculation result and actual production data of well X in Surig gas field is in good accordance. Besides, the impact of reservoir parameters upon production and morphology optimization were specifically analyzed. Using this new model, the production performance decline curves were drawn up based on computing results and were thoroughly analyzed for the sensitivity of reservoir parameters, especially the natural fractures. As presented in the performance curves, the post-frac production is greatly influenced by the change of permeability in fracture network, also confirming the applicability of this new model in fractured tight sandstone gas reservoirs.

1. Introduction

Naturally fractured tight sandstone gas reservoir refers to dual medium reservoir which consists of large scale of fracture network and complex porous matrix (Warren and Root, 1963; Gilman and Kazemi, 1982; Flamenco-Lopez and Camacho-Velazquez, 2001). It is characterized by the low porosity and low permeability with local high porosity and high permeability (Hareland and Rampersad, 1994; Brown et al., 1995). Owing to these unique characteristics, it cannot obtain economic benefits without horizontal well multi-staged fracturing technology. Hence, great scientific interest has been generated and extensive research was carried out (Dan, 2015).

Three main productivity evaluation methods have been used along with the application process of MFHWs since 1980s: (1) Physical modeling. It was first proposed by Giger in 1985, noting that electrolysis experiments can be used to simulate the production process of horizontal wells. Sand-pack model is another physical one to conduct some simple simulations. (2) Analytical solution. Based on a highly abstract physical model, the researchers describe the flowing state of reservoir fluid through a set of mathematical methods, and then an analytical solution could be acquired. (3) Numerical simulation. Solution of numerical simulation mainly includes finite difference method (FDM) and finite element method (FEM), where FEM is more widely used for its flexibility and accuracy on meshing (Marcondes et al., 2013;

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Abushaikha et al., 2015). Studies show that physical modeling is only applicable in some simple reservoirs, and the existence of non-Darcy flow exacerbate the experimental error (Roberts et al., 1991); in the early stage of oilfield exploitation, there is no advantage to use numerical simulation in production forecast owing to its insufficiency of geological data. Hence, analytical formulas got the favor of researchers due to its convenience and quickness (Raghavan and Joshi, 1993; Rahman, 2008).

One of the analytical methods is based on equivalent diameter principle. In the basis of conformal transformation and elliptic disturbance, the wellbore and each fracture could be regarded as a production segment of a vertical well, respectively (Settari et al., 2002; Smith et al., 2004; Miskimins et al., 2005; Guo and Yu, 2008; Wang et al., 2015). Complex potential theory and superposition principle are the foundation of another analytical method (see Fig. 1). Coupling the reservoir fluid, fracture fluid and wellbore fluid, this method can calculate the unsteady productivity of horizontal wells. Besides, taking into consideration of the fracture disturbance also improves its accuracy.

Conlin et al. (1990) firstly established a 1/4 model of hydraulic fracture to predict production performance of horizontal well multistage fracturing. Sennhauser et al. (2011) modified Conlin's model with the consideration of reservoir characteristics and seepage characteristics in fractures. Zerzar and Bettam (2004) calculated the analytical solution with the application of boundary element method and Laplace transformed method. As extension of previous works, Ozkan et al. (2006) derived an analytical solution of single fracture, obtaining the post-fracturing production by superposition principle. Nevertheless, historical works simplified the fracture conditions. The following assumptions were made while creating those models: the hydraulic fractures are perpendicular to the horizontal wellbore; the fractures are symmetrically distributed and the mutual interference among fractures can be ignored.

Generally, each fracture is formed with different combinations of length, width, fracture interval and azimuth angle, etc. To overcome this deficiency in models, many studies on the impact of asymmetric distribution and irregular geometry of fractures have been performed in the last decades (Li et al., 2012; Zhang et al., 2013; Zanganeh et al., 2015; Ren and Guo, 2015). The earliest use of potential theory and superposition principle to calculate the

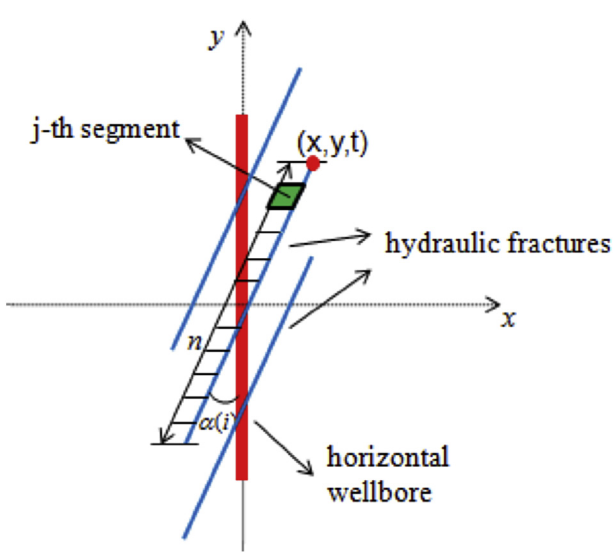

Fig. 1. Schematic illustration of hydraulic fractures divided into n segments to use superposition method.

production came from Lang and Zhang (1994). As extension of historical works, Tang (2010) and Chen et al. (2012) made a sensitive analysis of fracture morphology and its asymmetric distribution upon post-fracturing production via the establishment of production forecast model. Based on gas state equation and pseudo-pressure function, Zhong (2013) derived a mathematical calculation model of horizontal well staged fracturing in tight gas reservoirs; Rbeawi and Tiab (2013) established several models to predict productivity index for hydraulically fractured formations; Lin and Zhu (2014) developed a semi-analytical solution of fractured horizontal wells. All of them did not consider the existence of natural fractures.

Prior research has not focused on the influence of micro-fracture network, which lead to an obvious deviation in production forecast of naturally fractured tight sandstone reservoirs. Hence, a vital task is to establish a new model considering the impact of natural fractures. It is anticipated that this paper will be possibly a step forward in this area.

2. Methodology

In this paper, based on Warren-Root's model, the author combines complex potential theory, superposition principle with dual-medium gas reservoir seepage theory together to derive a productivity calculation model of a multiple fractured horizontal well, where the influence of nature fractures was emphatically considered. Then a mathematical model was extracted from the established physical model, leading to a semi-analytical solution by programming. Moreover, the impact of reservoir parameters upon production and morphology optimization was specifically analyzed through production performance decline curves.

3. Physical modeling and assumptions

Fig. 2 is the plan view of horizontal well and hydraulic fractures in fractured gas reservoir. As shown in this sketch, fractured tight sandstone gas reservoirs are naturally structured by matrix system and fracture network which have relatively independent physical properties. Thus, different formulas are employed to describe the behavior of gas flow through them. After multistage fracturing treatment, a stimulated reservoir volume (SRV) could be formed owing to the induced-stress-interference as well as the existence of natural fractures, which is presented as non-parallel or asymmetric main hydraulic fractures in Fig. 2. It is worth noting that although differences do exist, the rough orientations of main fractures are consistent (perpendicular to the minimum principal stress directions). The exaggerated expression in figures is to make a distinction.

The schematic diagram of dual medium model is shown in Fig. 3. For a given single horizontal well in the reservoir, the gas from the matrix system would eventually flow into the well bore through natural fractures and hydraulic fractures.

The transport process is the gas flows from micropores in matrix system and diffuses into fracture network (i), then flows through hydraulic fractures (ii) into well bore (iii). As shown in Fig. 3, the fluid channeling between natural fractures and well bore can be ignored (Zhang et al., 2013).

Certain assumptions and simplifications were made in order to create and solve a mathematical model analytically. The assumptions are as follows:

1. The dual medium gas reservoir is considered homogeneous, isotropic and sealed.
2. The model is isothermal; the gravitation effect and frictional resistance is assumed to be ignored.