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A fractional decline curve analysis model for shale gas reservoirs

Lihua Zuo, Wei Yu *, Kan Wu

Department of Petroleum Engineering, Texas A&M University, College Station, TX, USA

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ABSTRACT

In the past several decades, in order to have quick and direct methods to perform production forecasting and reserves estimation in practice, petroleum engineers have designed various techniques to interpolate the production rate both analytically and numerically, among which many decline curve analysis models have been proposed and widely used because of their simplicity and efficiency. Although all decline curve analysis models could be employed in some cases under certain assumptions, each has its own limitations and is not applicable for all cases. With the increasing interest in shale gas reservoirs, engineers have found a common long-tail behavior for gas production profile of shale gas wells, which cannot be well described by the current decline curve models. In this paper, based on the anomalous diffusion phenomena that also have the long-tail behavior, we developed a new fractional decline curve (FDC) model with three fitting parameters using the general solution of the fractional diffusion equations, which is a special case of so-called Mittag-Leffler function. In addition, we proposed a four-step scheme according to the asymptotic properties of the Mittag-Leffler function to quantify the three parameters. We verified the new FDC model against a numerical reservoir model. In addition, we applied the FDC model to perform history matching and production forecasting for five actual shale-gas wells from the Fayetteville Shale. The results show that the new model is easy to use and provides a reliable estimated ultimate recovery (EUR), which can help the petroleum industry to perform data analysis rapidly and forecast production more accurately in shale gas reservoirs.

1. Introduction

Shale refers to a fine-grained sedimentary rock, which was formed from the compaction of silt and clay-size mineral particles (EIA, 2015). In general, shale formation is characterized by very low porosity and permeability (nano-Darcy) and contains organic materials, which cannot be produced economically without any stimulation. However, the combination of horizontal drilling and multi-stage hydraulic fracturing has made the commercial development of Barnett Shale, which led to the development of the other shale reservoirs in the U.S. such as Marcellus, Utica, Eagle Ford, Haynesville, and Fayetteville Shale.

Over the past decade, large volumes of natural gas have been produced economically from shale formations. U.S. Energy Information Administration (EIA, 2013) reported that the United States has 665 trillion cubic feet (TCF) technically recoverable shale gas resources. It is predicted that shale gas production will increase from 40% of total U.S. dry gas production in 2012 to 53% in 2040 (EIA, 2014). Until now, tens of thousands of horizontal wells have been drilled in the United States. Hence, it is important to accurately and efficiently perform production forecasting and reserves estimation for these shale gas wells.

Hydraulic fracturing treatments in shale gas reservoirs often create complex fracture geometry. The gas present in the fracture system is produced at the early time. After that, the gas stored in the matrix system dominates the long-term production due to the contributions of various gas transport mechanisms, including gas slippage, gas diffusion, and gas desorption (Sakhaee-Pour and Bryant, 2012; Akkutlu and Fathi, 2012; Xu, 2014; Javadpour et al., 2015; Naraghi and Javadpour, 2015). In general, the production of a shale-gas well declines rapidly at the early time and then slowly over time. Additionally, shale gas wells often have a long-duration transient flow before reaching the boundary dominated flow regime, which could continue for several years due to low permeability. Accordingly, it is challenging to accurately perform production forecasting and reserves estimation in shale gas reservoirs.

In recent years, there are significant improvements to develop advanced numerical models to simulate shale gas production (Mirzaei and Cipolla, 2012; Olorode et al., 2013; Wu et al., 2014; Sun et al., 2015; Sun and Schechter, 2015; Du et al., 2015). However, the flow behaviors in shale gas reservoirs are still not fully understood. One of the challenges is that the numerical models are difficult to simulate the complex fracture system efficiently. Another challenge is that the existed multiple gas transport mechanisms make it not easy to determine which one controls the gas transport. Furthermore, the shale formation properties such as permeability and relative permeability are very difficult to be measured accurately. In practice, we often need to

* Corresponding author.
E-mail address: yuwei127@gmail.com (W. Yu).

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perform history matching with a large number of wells in a short period of time. However, the advanced numerical models require more time and effort to achieve this goal (Lee and Sidle, 2010). Hence, simple analytical or empirical models can play an important role in performing production analysis and reserves estimation. Since 1920s, researchers started to apply decline curve analysis to history match production data and forecast estimated ultimate recovery (EUR) in conventional reservoirs (Johnson and Bollens, 1927). Also, it has been presented that projection of production decline curve is the most widely used approach for forecasting production from shale gas wells (Lee and Sidle, 2010).

In the literature, several decline curve models have been applied to perform production forecasting in shale gas reservoirs, including Arps model (Arps, 1945), power law exponential decline model (Ilk, et al., 2008), stretched exponential production decline (SEPD) (Valkó and Lee, 2010), Duong model (Duong, 2011), logistic growth model (LGM) (Clark et al., 2011), and Weibull growth model (Mishra, 2012). Each of these models has its own strengths. Among the models mentioned above, the Arps model is the most utilized method for rapid evaluation of well production data. However, the Arps model often leads to the optimistic reserve estimates for shale gas wells due to the assumption that the well is under boundary dominated flow and produces at constant bottomhole pressure (Shahamat et al., 2015). However, most shale gas wells rarely reach the boundary dominated flow. The other models generally can provide better results than the Arps model under some conditions while they may produce unreasonable reserve estimations if without considering the associated assumptions (Shahamat et al., 2015). In addition, the complex fracture geometry and matrix systems may cause a long-tail phenomenon at later time of shale well production, which cannot be well described by the models above. Nevertheless, it has been studied in the fields of geology that the long-tail phenomenon is statistically caused by the so-called anomalous diffusion (Nakagawa et al., 2010).

From the view of statistical physics, “normal diffusion” is based on Brownian motion of the particles. The spatial probability density function evolving in time, which governs the Brownian motion, is a Gaussian distribution whose variance is proportional to the first power of time. In contrast, several experiments have found “anomalous diffusion” that is characterized by the property that its variance behaves like a non-integer power of time. For example, Adams and Gelhar (1992) presented that some field data which show anomalous diffusion in heterogeneous aquifer cannot be simulated well by the classical diffusion equation. Also, Nakagawa et al. (2010) illustrated that in the soil contamination process there is a big difference between the actual diffusion profile of contaminants underground and the theoretical one predicted by conventional diffusion equations.

The corresponding equations predicting the anomalous diffusion are called fractional diffusion equations. Many researches have been working on the anomalous diffusion and the corresponding fractional diffusion equations. For examples, Chaves (1998) derived a fractional diffusion equation to describe Levy flights, and Metzler and Klafter (2000) illustrated a fractional diffusion equation with respect to a non-Markovian diffusion process. Zhou and Selim (2003) showed that subdiffusion in porous media, such as a heterogeneous aquifer, can be characterized by a long-tailed profile in the spatial distribution of densities. On a more theoretical level, Nigmatullin (1986) first considered the fractional initial boundary value problem, which led to several theoretical and numerical results. Mainardi et al. (2001) constructed a fundamental solution in free space for time/space fractional diffusion equations, respectively, by employing the so-called Wright function. Luchko et al. (2009, 2010) obtained the maximum principle and the unique existence of the generalized solution. Sakamoto and Yamamoto (2011) studied the uniqueness of weak solutions and the asymptotic behavior. Luchko and Zuo (2014) studied the explicit form of the forward functions for subdiffusion equations. Many numerical approaches to solve non-local equations based on fractional derivatives have been proposed. On the inverse problem side, Jin and Rundell (2012) considered the identification of a potential term from the lateral flux data at one fixed time instance corresponding to a complete set of source terms, and established the unique determination for ‘small’ potentials. Rundell et al. (2013) studied the recovery of a nonlinear boundary condition from the lateral Cauchy data using an integral equation approach, and a convergent fixed point iteration method was suggested. The influence of the imprecise specification of the fractional order α on the reconstruction was examined. Luchko et al. (2013) showed the uniqueness of recovering a nonlinear source term from the boundary measurement, and developed a numerical scheme of fixed point iteration type. And recently, Jin and Rundell (2015) presented a tutorial of various inverse problems for time-fractional and space fractional diffusion equations.

In this study, we first presented a review of three popular decline curve models, Arps, SEPD and Duong model. Then, based on the same long-tail behavior between the shale gas flow rates and the anomalous diffusion, we introduced the fractional diffusion equations which can model the anomalous diffusion phenomenon. The new fractional decline curve model was proposed using the general solution for the fractional diffusion equations, which is a special case of the Mittag-Leffler function. The asymptotic behavior of the Mittag-Leffler function was then used to design a four-step procedure to build the fractional decline curve model, which was direct, reliable and easy to use. We used a numerical reservoir simulator to verify our model. Then the field production data of five horizontal wells from Fayetteville Shale were selected to show the applicability and efficiency of our model, illustrating that the fractional decline curve could produce reliable reserves estimation.

2. Methodology

2.1. Review of popular decline curve models

Decline curve analysis (DCA) has been an effective and efficient method to analyze well production history and predict EUR for several decades in the petroleum industry. In the literature, three decline curve models, including Arps decline model, SEPD, and Duong model, are widely applied to analyze well performance in unconventional oil and gas reservoirs, which are briefly summarized and discussed in the following subsections.

2.1.1. Arps decline model

Arps decline model is the most classical method, using hyperbolic function with three fitting parameters to describe the relationship between the well production rate and time. According to the observations on a large amount of production data, Arps (1945) proposed the assumption that “first differences of the loss ratios are approximately constant”, which can be described in the following mathematical form:

$$\frac{d\left(\frac{q}{dq/dt}\right)}{dt} = -b, \tag{1}$$

where q is well production rate, t is time, and b is a positive constant. Through integrating Eq. 1 twice, we can obtain a hyperbolic rate-time relationship as follows:

$$q = q_i\left(1+\frac{bt}{a_i}\right)^{-1/b}, \tag{2}$$

where q_i is the initial production rate and a_i is the initial loss ratio.

If we let $D_i = \frac{1}{a_i}$, then we arrive at the following more popular form of Arps decline model:

$$q = q_i(1+bD_it)^{-1/b} \tag{3}$$