Journal of Petroleum Science and Engineering ∎ (∎∎∎∎) ∎∎∎–∎∎∎

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

History matching of naturally fractured reservoirs based on the recovery curve method

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ARTICLE INFO

Article history:
Received 3 February 2014
Accepted 5 December 2014

Keywords:
naturally fractured reservoir
dual porosity
matrix–fracture interaction
history matching
neighborhood-Bayes algorithm
genetic algorithm

ABSTRACT

The discrete fracture network (DFN) and Multiple-Continua concept are among the most widely used methods to model naturally fractured reservoirs. Each faces specific limitations. The recently introduced recovery curve method (RCM) is believed to be a compromise between these two current methods. In this method the recovery curves are used to determine the amount of mass exchanges between the matrix and fracture mediums. Two recovery curves are assigned for each simulation cell, one curve for gas displacement in the presence of the gravity drainage mechanism, and another for water displacement in the case of the occurrence of the imbibition mechanism. These curves describe matrix–fracture mass transfer more realistically and therefore can be of great use when obtaining historical production data.

This paper presents the potential of the RCM within the framework of history matching of naturally fractured reservoirs to determine the appropriate recovery curves. In particular, the phase contact positions of a sector model, extracted from a real fractured reservoir, are matched throughout the production history using the RCM. Therefore, the main contribution of this work is using the historical data of contact positions to obtain a better description of the matrix–fracture communication. The distribution of an ensemble of the history matched models was illustrated by Boxplot, and the Genetic Algorithm (GA) and the Neighborhood-Bayes technique (NAB) were utilized for optimization and uncertainty quantification, respectively. The calculated recovery curves results are in good agreement with the production history of the model and the Bayesian credible interval (P10–P90) of the proposed method is satisfactory. This work also confirmed the potential applicability of the combined GA and NAB method for optimization and uncertainty quantification purposes.

1. Introduction

One of the most widespread hydrocarbon formations around the world are naturally fractured reservoirs (Aguilera, 1995; Al-Kobaisi et al., 2009; Fadaei, 2008; Wu et al., 2004). The inhomogeneous nature of these kinds of reservoirs makes reliable modeling and simulation extremely challenging (Al-Kobaisi et al., 2009). Two common approaches to modeling naturally fractured reservoirs are the DFN and Multiple-Continua concepts. In the DFN approach fractures and matrix blocks are modeled individually based on statistically created fracture distribution maps. In the Multiple-Continua concept typically two distinct continua for matrix blocks and fracture networks are considered, each overlapping the other and each with its own set of properties (Aguilera, 1995; Wu et al., 2004). If the matrix–matrix flow is significant in the Multiple-Continua concept then the dual porosity/dual permeability model is used, otherwise the dual porosity model is employed (Aguilera, 1995; Warren and Root, 1963; Wu et al., 2004). The dual porosity concept was introduced by Barenblatt et al. (1960) and Warren and Root (1963). In this approach a fractured model with a highly interconnected set of fractures is idealized and homogenized to a regular network of matrix and fractures (Fig. 1).

For the connected matrix and fracture media two continuity equations can be written that are linked to each other by a term called the matrix–fracture transfer function. Actually, mass transfer between matrices and fractures is governed through the transfer function (Barenblatt et al., 1960). This term is a key factor in dual porosity models (Al-Kobaisi et al., 2009; Ramirez et al., 2009). The various current formulations of the dual porosity model differ mainly in the way this transfer function is defined. The general form of the transfer function valid for oil, water, and

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http://dx.doi.org/10.1016/j.petrol.2014.12.002
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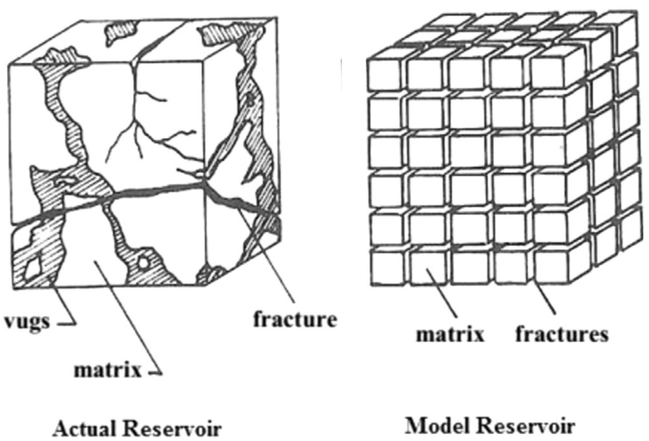

Fig. 1. Idealization of a NFR system (after Warren and Root (1963)).

free gas is

$$q_{\alpha_{mf}} = \frac{\sigma K k_{r_\alpha}}{\mu_\alpha B_\alpha}(\Phi_{\alpha,f} - \Phi_{\alpha,m}) \tag{1}$$

where α denotes the phase: oil (o), water (w) or gas (g), K is the average matrix permeability, μ is the viscosity, B is the formation volume factor, k_r is the relative permeability, Φ is the phase potential in the fracture (f) and in the matrix (m), and σ is the shape factor which represents the geometry of the matrix elements.

Since the introduction of the dual porosity concept about 50 years ago, many attempts have been made to improve this concept. The formulation of Warren and Root (1963) directly extended the multiphase flow by Kazemi et al. (1976), and numerically solved the dual porosity system in three dimensions. Gilman and Kazemi (1983) modified the treatment of mobility by changing the matrix/fracture transfer function to include fracture relative permeability when the fluid is flowing from the fracture to the matrix. Thomas et al. (1983) used pseudo-relative permeability and capillary pressure curves and presented another version of a fully implicit, three-dimensional, multiphase naturally fractured simulator based on the dual porosity approach. Gilman (1986) applied the fine grid to the model to more accurately obtain the gravity forces. Lim and Aziz (1995) derived matrix–fracture shape factors for a single-phase flow by applying analytical solutions of the single-phase pressure diffusion equation for various parallelepiped geometries of the matrix blocks.

In contrast to the current Darcy-like shape-factor approach of Gilman and Kazemi (1983), some researchers investigate each displacement process separately and use a semi-analytical approach to derive transfer functions for different recovery processes (Di Donato et al., 2007; Terez and Firoozabadi, 1999). Furthermore, in many studies concerning the matrix–fracture transfer in gas/oil or water/oil systems, attempts were made to develop general transfer terms (Al-Kobaisi et al., 2009; Heinemann and Mittermeir, 2011; Lemonnier and Bourbiaux, 2010; Ramirez et al., 2009). In this area, research results are also available from laboratory investigations and related numerical simulation in a single matrix block (Mason et al., 2010; Mattax and Kyte, 1962; Zendehboudi et al., 2011).

Despite these previous efforts the dual porosity concept is still far from the reality of matrix blocks and fracture networks; likewise, the DFN approach is a long way from being applicable in the field scale. The main problem of the Multiple-Continua concept is to find the correct formulation of the fluid exchange between the matrix and fracture media. This issue is more important when the fractures are water- or gas-filled, because the current formulations of the dual porosity model are mathematically rigorous for only a single phase flow. The present matrix–fracture transfer functions have been derived under many simplified and idealized assumptions. Taking into account all of the conditions that exist during the actual mass exchange between matrix blocks and fracture networks, it is not yet possible to obtain an actual transfer function. Moreover, the main challenge of the DFN model is its calculation cost (in terms of CPU-time and memory). With current computational capabilities, modeling a typical NFR field with the DFN method is almost impossible (Amiry, 2014; Lemonnier and Bourbiaux, 2010; Sarma and Aziz, 2006; Wu et al., 2004).

Recently, the RCM has been introduced by Heinemann (2004) to deal with these challenges and to use the benefits of the two-current modeling approaches of naturally fractured reservoirs. It is believed that the RCM is a compromise between the two approaches and is an improvement over the Warren–Root sugar cube model. Pirker and Heinemann (2008) and Pirker et al. (2008) developed a very efficient numerical method to generate recovery curves for a matrix block. Amiry (2014, 2012) compared the simulation results of the RCM and the conventional transfer function method. He showed that under the same conditions the results of the recovery curve method and those of classical conventional methods are similar, and the two approaches can be combined both in space and in time. Section 2 discusses the principles of the RCM in details.

History matching or using available data to update reservoir models is one of the main techniques used during the development and management of petroleum fields. In this process the reservoir model is conditioned to the history of the production data. In other words, in history matching some parameters of the simulation model are altered to match the simulation results with real field production data. To have a reliable prediction of the future performance of the reservoir, reasonably matched models are necessary. Several data are used to build the reservoir models including well logs, well tests, and seismic data. Each of these data is associated with its own uncertainties. Hence, building the correct reservoir model to represent the various available data is very difficult (Hajizadeh et al., 2011). History matching of fractured reservoirs is even more challenging because obtaining the right data to characterize the fractures and forecasting the reservoir performance is much more difficult in fractured reservoirs. In general, history matching algorithms are classified into four categories: stochastic algorithms, gradient-based methods, streamline-based techniques, and Kalman filter approaches (Sarma et al., 2006).

Many efforts have been made to produce reasonable history matching in naturally fractured reservoirs. Watson et al. (1990) performed a history match of the production data of a naturally fractured gas reservoir. In their method a normalized time was used to modify the analytical solutions to model gas flow in finite, dual-porosity reservoirs. The proposed method suffers from some critical assumptions including only a single fluid phase and homogeneity of reservoir properties. Smith and Tan (1993) employed a three-dimensional three-phase reservoir simulator with automatic history matching capability for NFR. Furthermore, Gang and Kelkar (2006) performed history matching by modifying the fracture permeability of individual fractures and the water–oil capillary pressure curves. Suzuki et al. (2007) utilized elastic stress simulation and the probability perturbation method for history matching purposes. Moreover, conditioning the fracture intensity model to the production data was implemented by Cui and Kelkar (2005). Hu and Jenni (2005) presented a methodology for faulted and fractured reservoirs based on a generalization of the gradual deformation method for calibrating Boolean simulations to dynamic production data. Also, Paico (2008) used a gradient-based history matching procedure to a discrete fracture network

Please cite this article as: Ghaedi, M., et al., History matching of naturally fractured reservoirs based on the recovery curve method. J. Petrol. Sci. Eng. (2014), http://dx.doi.org/10.1016/j.petrol.2014.12.002