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A new mathematical model considering adsorption and desorption process for productivity prediction of volume fractured horizontal wells in shale gas reservoirs

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ABSTRACT

It has proved that seepage flow of shale gas reservoirs is much more complicated compared to most conventional reservoirs due to massive multistage, multi-cluster hydraulic fracturing stimulations. It becomes crucially essential to develop new methods to better stimulate such a complex system, further understand the recovery mechanisms, and perfect optimization development plans of shale gas reservoirs. The published three linear flow models simplified the complex process and got very good results. However, desorption and adsorption mechanism, which is the key mechanism of shale gas reservoirs, was ignored. Consequently, in this paper, a numerical model considering desorption and adsorption process was established and solved under the polar coordinates and the Laplace space respectively to predict productivity of volume fractured horizontal wells in shale gas reservoirs. Single well productivity formula and bottom hole pressure formula of shale gas reservoirs were developed. In addition, based on the new established numerical model and its analytical solution, productivity of a volume fractured horizontal wells in a shale gas reservoir of Western China were calculated and compared with both the actual production data and results predicted by Eclipse simulator. Results showed that the predicted results are in good agreement with the field test. Although the simplifications resulted in errors to some extend, the improved trilinear model can also be recommended for the production prediction of the fractured horizontal wells in shale gas reservoirs. It is concluded that computational convenience of the trilinear-flow solution makes it a practical alternative to more rigorous but computationally intensive and time-consuming solutions.

1. Introduction

Economic production can be only achieved by massive stimulation treatments in shale gas reservoirs because of the ultra-low permeability of the rock. Horizontal wells are considered to be more cost effective in achieving commercial production. The limited field experience with multiple hydraulic fractures in horizontal wells indicates that significant increase in initial production can be achieved as the number of hydraulic fractures is increased (Clarkson and Pederson, 2010). However, the production performance, particular over longer time periods, is not well established. And modeling fluid flow in such complex reservoirs remains challenging (Obinna and Hassan, 2014).

Production of horizontal wells from unconventional shale reservoirs is a result of flow in shale matrix, in the reservoir fracture network, and in hydraulic fractures (Brown et al., 2009a,b). Triple-porosity models can be classified into pseudo-steady and transient state models based on matrix–fracture interaction. It could comprise two fracture networks and one matrix or two types of matrix and one fracture network. Liu et al. (2003) analyzed the pressure behavior of fractured reservoir including fractures, matrices and cavities. Based on this model, Wu et al. (2004) simulated the flow and transport processes. Dehghanpour and

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Shirdel (2011) extended the transient dual-porosity model of Ozkan et al. (2010) and pseudo-steady model of Warren and Root (1963), which could used to explain the unexpected high gas production in some shale gas reservoirs. Al-Ahmadi (2010) extended the linear dual-porosity model of Bello and proposed four dual-fracture triple porosity models for linear reservoirs.

Although it is possible to develop detailed analytical (Chen and Raghavan, 1997; Raghavan et al., 1997) and numerical models (Mediros et al., 2008) to represent transient fluid flow toward a multiple-fractured horizontal well in shale gas reservoirs, the drawback of these models includes the increased computational requirements, the implicit functional relationships of key parameters, and the inconvenience in their use in iterative applications. If, however, the natural-fracture network is a result of shear slippages because of hydraulic fracturing and localized around the horizontal well then some simplifications are possible.

Natural gas within the shale gas formations is present both as a free gas phase and as adsorbed gas. Carbon-rich components are the mainly adsorbed space. Total organic content (TOC) in shale and reservoir pressure are two of most important factors. Generally, the adsorbed gas represents significant quantities of total gas reserves (20–80%) as well as recovery rates, which cannot be ignored in any model or modeling analysis.

Unconventional reservoirs are often characterized by dual porosity model (Warren and Root, 1963). Shale gas reservoirs are one of the most typical representatives. Natural gas within the dual porosity reservoirs exists in both rock matrix and fractures. Matrix has lower permeability but contains most of the gas, while fractures have greater permeability and is the main flow channel. Theoretical research and field tests showed that both hydraulic fractures and natural fractures play important roles in production performance in shale gas reservoirs.

Rosa and Cavalho (1988) extended the horizontal well solutions to dual porosity systems for the first time. Lu et al. (2009) concluded that there exist a number of flow regimes but some of them could be simplified or even eliminated depending on reservoir parameters. The flow regimes include the early radial flow (in vertical direction) and it has short duration in thin or high vertical permeability reservoirs. The next flow regimes is known as intermediate linear flow regime and is developed because the length of horizontal well is often much greater than the formation thickness. Subsequently, the transition period becomes dominant, and finally late radial flow period is observed. Ozkan et al. (2009) and Brown et al. (2009a,b) introduced the concept of trilinear flow for hydraulically fracture horizontal wells. They indicated that the contribution of micro-darcy formation beyond the stimulated volume is negligible and flow is mainly linear perpendicular to the hydraulic fracture. The trilinear flow couples three linear flow regions including the hydraulic fracture, the inner area between the fractures, and the area beyond the tip of the fracture.

The specific objectives of this paper are to develop a novel mathematical model and its analytical solution using production data, and to improve basic understanding of the production performance of horizontal wells with multiple hydraulic fractures in shale gas formations. In addition, the applicability of the newly developed model are validated and demonstrated by a field example in productivity of a shale gas well.

2. Model

2.1. Trilinear seepage model and its assumptions

For hydraulically fractured horizontal wells in shale gas reservoirs, the contribution of the reservoir beyond the stimulated volume is usually negligible (Mediros et al., 2008; Mayerhofer et al., 2010). Despite the complex interplay of flow among matrix, natural fractures, and hydraulic fractures, the key characteristics of flow convergence toward a multiply-fractured horizontal well within the SRV may be preserved in the trilinear-flow model presented by Ozkan et al. (2009) and Brown et al. (2011).

The model is not applicable if the regions beyond the well tips dominate the well response when the shale-matrix permeability is well above the macroDarcy (mD) range or the bottom-hole pressure or rate is unrealistically low. Other than that, the trilinear model can be used whenever the use of an analytical model is warranted by the complexity of the problem and the availability of data. For pressure transient-analysis purposes, analytical models are preferred if they can represent sufficient details of fluid and reservoir characteristics.

As shown in Fig. 1, the trilinear flow model couples linear flows in 3 contiguous flow regions (Brown et al., 2011):

- The outer reservoir beyond the tips of the hydraulic fractures
- the inner reservoir between hydraulic fractures
- the hydraulic fracture

Each region can have distinct properties. The inner reservoir may be homogenous or naturally fractured, and the hydraulic factures may have finite conductivity. To derive a practical model, some idealizations and simplifying assumptions are made.

1. The model is derived for single-phase flow of a constant-compressibility fluid. Single-phase gas flow is handled through pseudo-pressure transformation. Flow from the reservoir into the horizontal well is only by virtue of the hydraulic fractures; that is, the production directly from the surface of the horizontal well is assumed to be negligible.
2. Hydraulic fractures are assumed to have identical properties and are equally spaced by a distance, d_F, along the horizontal well. This assumption can be removed by an approach similar to that used by Raghavan et al. (1997); however, creating equally spaced hydraulic fractures of similar properties is a common field practice and, unless there is significant contrast in individual-fracture properties, the use of the average fracture properties should be sufficiently accurate. Moreover, our ability to discern individual-fracture properties from pressure-transient analysis is meaningless.
3. Flow in the inner reservoir between hydraulic fractures and flow in the outer reservoir beyond the tips of the hydraulic fractures are both assumed to be linear. Linear flow in the inner reservoir is a result of assuming either a non-perforated horizontal well between fractures or that the hydraulic fractures dominate production. The bisector of the distance between two hydraulic fractures is a no-flow boundary because of the assumption of identical hydraulic fractures.

Under the conditions assumed in the paper, parameters were defined as Fig. 1 shows.

- The subscripts m and f are used to denote the matrix and fracture media of the dual-porosity reservoir.
- The fracture is located centrally in the closed rectangular drainage area. The no-flow boundaries parallel to the fracture are located at the half-distance between two fractures, which is y_e, half of spacing between perforation clusters d_F.
- The lateral boundaries perpendicular to the fracture plane are at a distance x_e from the center of the fracture, which is half length of volume fracturing area.
- The number of fractures is $n_F = L/d_F$, where L is the length of horizontal section. Therefore, the drainage area of the fracture