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Full Length Article

A multiscale-multiphase simulation model for the evaluation of shale gas recovery coupled the effect of water flowback

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ABSTRACT

After fracturing operation, hydraulic fractures and induced fractures are created within the shale reservoir. A lot of treatment water is stored in fractures network and flow back into the surface during the gas recovery process. The gas production performance is affected by the water flowback because two phase flow occurs within fractures zone. For the created reservoir scale, we propose a multiscale- multiphase simulation model, which defines the whole domain as three sections. Section A contains the organic and inorganic matrix, which stores both the free gas and adsorbed gas. Flow processes are defined in the components of inorganic minerals and kerogens, respectively. For the section B and C, gas phase and water phase are existed together. Under this framework, a set of partial differential equations are derived to define various liquid transport processes: (1) gas flow in the kerogen system of matrix; (2) gas flow in the inorganic system of matrix; (3) gas-water two phase flow in fractures zone and (4) gas-water two phase flow in the hydraulic fracture system. Dynamic permeability models and mass exchanges between them are coupled for all systems. The model was verified against field production data from the Barnett Shale. Model simulation results show that flowback of treatment water can significantly affect the gas production rate at the early stage. Firstly, the increase of maximum water relative permeability can raise the water flowback rate and gas production rate but increasing non-wetting phase entry pressure will decrease the fluids flow rate. Secondly, the impact of fractures zone width on gas production performance is unstable and increasing initial water saturation can increase the water flowback rate but decrease gas production rate. Overall, the dynamic performances of water phase within fractures zone have significant impact on the short and long time shale gas recovery.

1. Introduction

In order to improve the unconventional natural gas recovery for shale reservoirs, hydraulic fracturing and horizontal well are the key approaches to be applied in field production. Hydraulic fracturing can create many bigger fractures within the reservoir and increase the contact area of matrix to the high permeability areas. In the previous study [10] the whole reservoir simulation is divided into two sections. One is the hydraulic and induced fractures and the other is shale matrixes between hydraulic fractures. The fully coupled model can predict the shale gas production performance accurately. However, it ignored the impact of the water flowback on the gas production behaviors, which makes that the prediction of reservoir simulation is a little higher than the actual field data at the early stage of production [10]. In this study, we proposed an improved multiscale-multiphase simulation model for shale reservoirs, which takes the impact of water flowback into account. The whole domain is divided into three sections namely section A, section B and section C on the basis of different flow mechanisms as shown in Figs. 1and 2. For the evaluation of shale gas recovery, it is critical to consider the different flow mechanisms within different scales.

Continuum mechanics theory is applied to investigate the gas transport within shale reservoirs for many years. Both the single porosity single permeability model [24] and dual porosity dual permeability model [29,31,32,26] are used to analyze the gas transport behaviors. The single porosity model ignores the differences between kerogen system and inorganic matrix system. Thus, dual porosity model seems more applicable for the gas shale reservoirs because there are many differences between inorganic matrixes and kerogens [19,30]. For both the kerogen and inorganic matrix, slippage effect is an important factor for gas transport mechanisms. Thus, dual porosity dual permeability model is used

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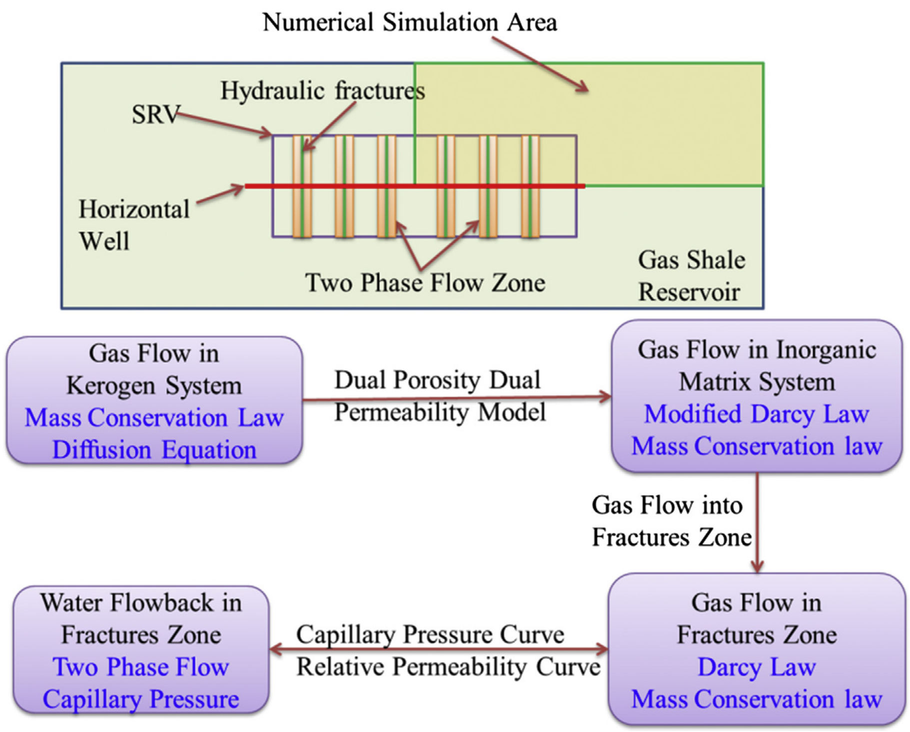

Fig. 1. Interactions and relationships among different systems in shale gas reservoir.

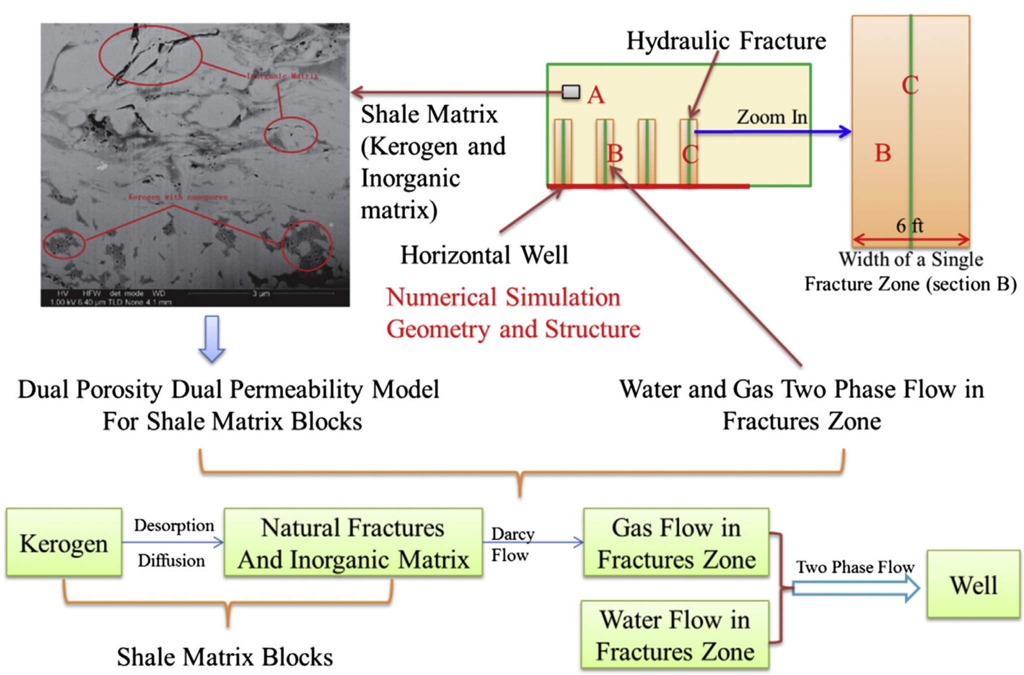

Fig. 2. Numerical simulation model for the shale reservoir (SEM graph from [5].

to formulate the gas mass transfer mechanisms for section A. The dynamic permeability models for kerogen and inorganic matrix have considered the impact of flow regimes on the permeability [23,14,8]. When the compressibility of matrix is very lower, the impact of effective stress on the permeability in section A can be ignored [11]. It is noticed that most reservoir simulation models for unconventional natural gas extraction ignore the operation of water flowback, which makes the prediction of gas production deviates from the field data. In this study, we focus on the impacts of water flowback on the gas recovery performance.

During the treatment of shale reservoir, tens of thousands of barrels of water are injected into a single well. 10–50% of the injected water can be recovered during the clean-up stage and initial period of production [22,20,7]. Most of the water will be retained in the fractures zone of reservoir. During the gas production operation, water can flow back into the horizontal well and it