Journal of Natural Gas Science and Engineering 46 (2017) 387–397

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

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

Reconstruction of porous structure and simulation of non-continuum flow in shale matrix

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ARTICLE INFO

Article history:
Received 30 January 2017
Received in revised form
19 August 2017
Accepted 20 August 2017
Available online 24 August 2017

Keywords:
Image reconstruction
Pore network
Non-continuum flow
Surface diffusion
Apparent gas permeability

ABSTRACT

Distribution and connectivity of pores in shale is difficult to characterise due to their nano-micro multiscale characteristics. Flow in the porous structure is correspondingly controlled by multiple mechanisms and thus it is challenging to estimate the flow properties of shale gas. In view of this, the pore network was employed in this study to represent the porous structure and carry out flow simulation in an organic-rich shale matrix. A self-similarity based stochastic method, which combines the advantages of μ-CT and SEM, was used to characterise the porous structure with a resolution of 10 nm. A pore network of size of $10 \times 10 \times 10$ μm^3 was constructed by the maximum ball algorithm and the multi-physics flow (including the wide range non-continuum bulk flow and surface diffusion) was simulated in the reconstructed network. The simulation results show that the apparent gas permeability increases by a factor of 3.16, with 36% contribution arising from surface diffusion when the downstream pressure depletes from 9 MPa to 2 MPa. Sensitivity analyses imply that the apparent gas permeability is dependent on the size and shape of throats, compressibility factor of gas, Langmuir adsorption parameters and reservoir conditions.

1. Introduction

Commercial production of shale gas in the U.S. has ushered in a new era of unconventional energy extraction and inspired the industry to exploit the shale gas throughout the world. Intensive interests in understanding flow mechanism in shale have also led to development of new techniques for economic extraction of shale gas. As a fundamental property, permeability of shale gas attracts particular attention due to its importance in modelling and predicting gas production. In order to avoid the time-consuming laboratory measurement, analytical and numerical estimation of shale gas permeability becomes a favourable alternate. A consensus on the estimation method, however, has not yet been fully realised because of the complex porous structure of shale matrix and multiple mechanisms governing flow at multiple scales. Pores residing in organic and inorganic matters have been characterised as having heterogeneous connectivity (Loucks et al., 2012) and wide distribution of size (0.3–300 nm) (Ambrose et al., 2012). In these nanopores, mean free path of gas molecules becomes comparable to the pore size, resulting in velocity slip along the wall. Characterised by Knudsen number *Kn*, which is the ratio between mean free path of gas molecules and size of pores, flow within shale matrix is divided into four regimes: continuum flow ($Kn < 0.001$), slip flow ($0.001 < Kn < 0.1$), transition flow ($0.1 < Kn < 10$) and free molecular flow ($Kn > 10$) (Tsien, 1946; Yuan et al., 2016a, b). Traditional Darcy equation is valid to describe continuum flow while fails to capture the enhanced slip velocity in the non-continuum flow ($Kn > 0.001$) (Yuan and Rahman, 2016). In addition, since kerogen is randomly distributed in the matrix, the associated adsorption/desorption and surface diffusion pose difficulties in describing flow behaviour.

Both analytical and numerical models have been developed to estimate the apparent permeability of non-continuum gas flow in tight porous media like shale. In order to capture the slippage effect for the slip flow, Klinkenberg (1941) proposed a gas slippage factor to linearly correlate the apparent gas permeability and the intrinsic liquid permeability. This method is widely applied to the gas flow simulation but not applicable beyond the scope of slip flow. For free molecular flow, Knudsen diffusion is used to take into account of the increased collision between gas molecules and pore walls (Knudsen, 1909; Do, 1998), while for the transition flow, there is a general lack of understanding of the flow mechanism. Surface

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http://dx.doi.org/10.1016/j.jngse.2017.08.009
1875-5100/

diffusion is driven by the concentration gradient of adsorbed gas on the wall of kerogen and can be described by Fick's law (King, 1980; Medveď and Černý, 2011). Although equations have been derived to describe the individual flow mechanism, the occurrence of multiple flow regimes leads to the difficulty of simulating gas flow in the porous structure of shale. In order to resolve this difficulty, analytical equations have been developed on the basis of advection-diffusion model (ADM) and dusty gas model (DGM), and widely applied to estimate the gas permeability of shale. For example, Javadpour (2009) formulated an apparent gas permeability model which accounts for both the slip flow and Knudsen diffusion; following this, surface diffusion was incorporated into Javadpour's model by Zhang et al. (2015a, b). Alternatively, based on a general slip boundary condition, Beskok and Karniadakis (1999) proposed a semi-analytical model (termed as B-K equation) to describe the flow within entire range of *Kn*. Later, the authors (Yuan et al., 2015; Yuan and Rahman, 2016) implemented this slip boundary condition by a lattice Boltzmann method (LBM) to simulate flow in micro-channel with *Kn* up to 10. Because of its sound physical basis, the B-K equation has been widely adopted by researchers to estimate the shale gas permeability (Civan, 2010; Ziarani and Aguilera, 2012). It is notable that these models (Civan, 2010; Ziarani and Aguilera, 2012) are developed on the basis of a single straight capillary. The porous structure of shale, however, is complex in terms of wide range of pore size distribution, tortuous flow path and heterogeneous connectivity. Simulation results from a single capillary, therefore, cannot realistically describe flow behaviour in the complex porous structure of shale.

Some studies suggest the use of simulation results from a representative capillary to represent the property a porous medium. Kolodzie (1980) used the capillary size corresponding to the 35% of cumulative pore volume in a mercury intrusion capillary pressure (MICP) test to represent a porous medium. Ziarani and Aguilera (2012) applied B-K equation (Beskok and Karniadakis, 1999) to this capillary size to estimate the apparent gas permeability of shale. The representative size, however, varies among different studies; for example, capillary size at 25% and 10% cumulative pore volume in MICP was used by Pittman (1992) and Rezaee et al. (2012), respectively. This indicates that it is case-dependent to use a particular capillary size to represent the wide pore size distribution in the porous media. Thus, this method fails to become universally acceptable. In order to overcome this problem, Yuan et al. (2016a, b) presented a capillary model to represent the porous structure and employed the B-K equation to describe the dynamic flow process in shale. Although the model accounts for the wide size distribution and tortuosity of capillaries, it assumes that there is no connectivity between the capillaries and thus is not a realistic representation of the porous structure. Numerical analysis, *e.g.* LBM, has been implemented in the 2D porous matrix to estimate the apparent gas permeability of shale (Wang et al., 2016), but the 3D model is still in demand.

Pore network, which is extracted from images of porous structure, characterises the three-dimensional distribution and connection of pores and throats of rocks. It is thus regarded as a more realistic representation of the porous structure and adopted to simulate flow process and calculate transport coefficients, such as permeability, of porous media. The idea of network modelling was pioneered by Fatt (1956) and then used to simulate the single-phase (Koplik and Lasseter, 1984), two-phase (Koplik and Lasseter, 1985; Bryant and Blunt, 1992) and multiple-phase flow (Blunt, 2001) in conventional rocks, and recently to simulate the non-continuum gas flow in the unconventional porous media like shale. For instance, Sakhaee-Pour and Bryant (2012) employed a 2D regular square lattice network to model the effects of slippage and gas adsorption/desorption on gas flow through organic matrix of shale. It was found that the matrix permeability increases by a factor of 4.5 during production life of a well, due to the reduced thickness of adsorption layer and enhanced slippage effect. They noted, however, that this 2D network does not explicitly represent the distribution of voids in the sample. Mehmani et al. (2013) adopted Javadpour (2009)'s formulation for the single capillary into a 3D pore network, which accounts for the multiple flow mechanisms at nano- and microscale, to estimate the gas permeability of shales. Their study demonstrates that the apparent gas permeability of shale highly relies on the fraction of nanopores, *i.e.*, when nanopore fraction is over the threshold value of 0.2, the apparent gas permeability sharply decreases. Ma et al. (2014) superposed slip flow and Knudsen diffusion to describe the non-continuum flow in the single capillary and then simulated the gas flow through a stochastically constructed network of shale. Instead of ideal gas, real gas properties were used in the simulation, which leads to increased permeability by tens of percentage than that of ideal gas. In addition, network modelling of gas flow in shales has been carried out by others in similar approaches (Chen et al., 2015; Zhang et al., 2015a, b; Yuan et al., 2016a, b). These approaches can be summarised as follows: firstly, according to ADM or DGM, equations for individual flow regimes are linearly superposed to describe the non-continuum flow in the single capillary; next the coupled equation is employed in the 3D pore network, which is stochastically reconstructed from 2D images; and finally the apparent gas permeability is estimated.

There are, however, inherent problems with these approaches. Firstly, the pore network in previous studies is stochastically constructed from limited slides of 2D SEM images by Markov chain Monte Carlo (MCMC) method. By MCMC method, the reconstructed 3D porous structure is highly dependent on the properties of the 2D images and thus fails to realistically capture the characteristics of the porous medium and deliver accurate properties of gas flow. Secondly, there are contradictory views on description of non-continuum flow in the singe capillary; for example, rather than “slippage and Knudsen diffusion” (Mehmani et al., 2013; Ma et al., 2014; Zhang et al., 2015a, b), superposition of “viscous flow and Knudsen diffusion” was used by Chen et al. (2015) and Ren et al. (2016); Wu et al. (2015a, b, c) and Wu et al. (2016a, b, c) considered that instead of direct superposition, weighted factors should be multiplied to the terms of slippage and Knudsen diffusion. Thirdly, the effect of surface diffusion occurring on the adsorption layer has not yet been taken into account in the published network models, although some studies in the single capillary are carried out (Wu et al., 2016a, b, c; Yuan et al., 2016a, b). An improved method, therefore, is in demand to simulate the multiple flow mechanisms in the porous structure of shale.

In this paper, we introduce a self-similarity based stochastic (SSBS) method, which allows us to combine 2D SEM images with 3D μ-CT images, to characterise the 3D porous structure of a typical shale sample. B-K equation and Fick's equation are employed to describe the non-continuum flow and surface diffusion in the porous structure, respectively. The rest of the paper is organised as follows: the multi-mechanism of gas flow in a single capillary is described in Section 2; methodologies for construction of multi-scale pore network and flow simulation within that are illustrated in Section 3 and Section 4, respectively; sensitivity analyses are carried out in Section 5 to test the effects of controlling parameters, such as pore size and gas type, on the apparent gas permeability, which is followed by the conclusion in Section 6.

2. Flow in the single capillary

Flow in the porous structure of shale consists of non-continuum flow in the body of pores, termed as bulk flow, and the surface