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A sequential model of shale gas transport under the influence of fully coupled multiple processes

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ABSTRACT

Shales have complex microscopic pore structures which significantly affect shale gas production. Effects of microscopic pore structure on flow regimes have been widely investigated. The pressure dependent permeability in shales has been also observed in laboratory and it may cause more significant variation in apparent permeability than flow regimes does. Therefore, numerical models combining flow regimes and pressure dependent permeability are required to describe the gas flow behaviour in shales. In this study, based on literature experimental observations, a numerical simulation model for shale gas transport was built. The model includes the main gas flow characteristics in shale: (1) sequential flow process of different flow regimes for different pores; (2) variation of apparent permeability resulted from both flow regimes and stress variation in shale; (3) permeability change with respect to strain. Nine sets of literature experimental data were used to verify this numerical simulation model, which was shown to be able to accurately describe the data. Using this numerical simulation model, shale gas flow behaviour was analysed and the following conclusions were found: (1) the effect of shale deformation on gas production is significant. Compared with other factors, it is a considerably important factor controlling the apparent permeability evolution during shale reservoir depletion; (2) natural fracture plays a significant role in gas transport inside reservoirs. Although its porosity is much less than those of other pores, it could obviously enhance shale gas recovery rate because of its higher permeability; (3) natural fracture permeability, natural fracture porosity, inorganic pores permeability and Young's modulus have positive correlations with shale gas recovery rate. However, the percentage of adsorbed gas has a negative correlation with shale gas recovery rate.

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1. Introduction

The production behaviour of shale gas may have an inherent link with its diversity of minerals and the complexity in microscopic structure. Shales normally contain quartz, clays, carbonates, and organic material (e.g. kerogen) (Wang and Reed, 2009; Sondergeld et al., 2010). They are also consisted of pores with a wide range of sizes (Nelson, 2009; Loucks et al., 2012). Characteristics of shales make the gas storage and flow in shale different from other porous media. For instance, majority of methane stores as adsorbed phase in coals, while both free gas and adsorbed gas have considerable amount in shales (Curtis, 2002; Olsen et al., 2003). In laboratory, a huge difference in methane release behaviours between shales and coals was observed (Javadpour et al., 2007).

In shale-gas systems, the microscopic pore structure contains matrix-related pores and natural fractures. The matrix-related pores are composed of nanometre-to micrometre-size pores. The natural fracture connects to hydraulic fractures and its network plays an important role in shale gas production (Gale et al., 2007). The unique microscopic structure of shales affects gas production in two main aspects. First, the process of gas release from shales experiences several flow regimes due to its complex network of flow path in shales. The flow regimes for different size pores could be significantly different. To classify them, the Knudsen number, the ratio of the mean-free-path of gas to the pore diameter is used to distinguish these regimes from the free-molecule flow to the

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continuum flow (Roy et al., 2003). Secondly, pores in shales would experience complex geomechanical deformations during shale gas depletion. The geomechanical deformations significantly affect apertures of flow paths which determine permeability. Therefore, an effective numerical simulation model should contain all these effects of microscopic structure on shale gas production.

To involve deviation of gas flow regimes, many numerical simulation models for gas transport in shales have been proposed and Knudsen number is widely used to differentiate the flow regions in shales (e.g., Civan et al., 2011; Javadpour, 2009; Ye et al., 2015). Non-Darcy equations for gas flow, which include Knudsen diffusion and slip flow, have also been proposed and studied (e.g., Guo et al., 2015; Javadpour, 2009; Moghadam and Chalaturnyk, 2014). However, flows in different regions are not only different but also interacting with each other. Early work considering interactions between different flow paths is dual-porosity model for porous media proposed by Warren and Root (1963). Such dual-porosity approach has been adopted to describe flow in shales (Carlson and Mercer, 1991). Nevertheless, dual-porosity models treat the fluid in matrix as a source of the flow in fractures and ignore fluid flow in matrix. Other work tried to account for flows in different flow paths. For instance, multi-continua at the naturally fractured reservoirs was developed and applied (Bear and Bachmat, 1990). For shale reservoirs where gas flows in both matrix pores and fracture system, a multi-scale model combining dual-porosity concept and multi-continua theory for gas transport in shales has been proposed (Kang et al., 2011; Akkutlu and Fathi, 2012). The advantage of these models is that interactions between different flow paths can be mathematically described. Other method to include interactions between different flow regions is the multiple interacting continua (MINC) method (Pruess, 1985). In the MINC method, each matrix block is subdivided into several nested "sub-cells" and interactions in matrix blocks are defined by connecting factors between these sub-cells. Rubin (2010) used this method to investigate shale gas production. This method was improved by determining inter-cell connecting factors (Ding et al., 2014). To account for effect of microscopic structure on gas flow, the apparent permeability (k_{app}) is applied in all studies mentioned above. However, they only focused on the correlation coefficient (k_g) between k_{app} and intrinsic permeability (k_∞), which is assumed to be constant. Nevertheless, it is not appropriate to assume constant intrinsic permeability because the intrinsic permeability significantly changes during shale gas depletion.

The intrinsic permeability has a close relationship with diameter of pores and porosity of rocks (e.g., Nelson, 2009; Cho et al., 2013). During shale gas depletion, the geomechanical deformation of shales can dramatically affect porosity so the intrinsic permeability is often observed as pressure dependent. The pressure and field production data demonstrated evidence of pressure dependent permeability in Horn River and Haynesville shales (Vera and Ehlig-Economides, 2013). Laboratory measurements also showed that intrinsic permeability decreases with effective stress (Dong et al., 2010; Tinni et al., 2012; Heller et al., 2014; Wang et al., 2014; Ghanizadeh et al., 2015). Comparisons between Klinkenberg effect and effective stress effect on permeability of shales were investigated in laboratory as well. When pore pressure exceeds 500 psi (around 3.5 MPa), the Klinkenberg effect would not significantly affect permeability (Wang and Reed, 2009). Effective stress, ranging from 0 MPa to 100 MPa, always significantly affects shale permeability (Dong et al., 2010; Wang et al., 2014). To account for the large change in intrinsic permeability during gas production, numerical simulations require an intrinsic permeability model.

Currently, great efforts have been made to model intrinsic permeability of porous media. It has been pointed out that the change of intrinsic permeability has an exponential relationship with effective stress (Rutqvist et al., 2002) or the strain of porous media (Minkoff et al., 2003). Mechanical conditions in the field are usually assumed as uniaxial strain and constant overburden (e.g., Shi and Durucan, 2005). Under this condition, intrinsic permeability has a relationship with pore pressure (Raghavan and Chin, 2002). In order to incorporate the effect of methane adsorption into intrinsic permeability models for coal reservoirs, many models with stress-based and strain-based forms have been proposed according to the field conditions (e.g. Gray, 1987; Palmer and Mansoori, 1996; Shi and Durucan, 2005). To overcome their limits resulted from assumption of mechanical conditions, an improved permeability model was proposed by Palmer et al. (2007) and a model derived from poroelastic theory was proposed by Zhang et al. (2008). These models were valid for a single porosity medium. Shale contains several pore structures and is not a single porosity medium. Therefore, it is not applicable to use these models to describe the intrinsic permeability for shales. In general, intrinsic permeability of matrix system is several orders of magnitude lower than that of fracture system in fractured media such as coals and shales (Han et al., 2010; Ghanizadeh et al., 2015). In this case, mass transfer between fractures and matrix is a dynamic process. The importance of these interactions for intrinsic permeability has been illustrated for coal reservoirs (Harpalani and Chen, 1997; Liu and Rutqvist, 2010; Liu et al., 2011; Peng et al., 2014a). To incorporate this impact on intrinsic permeability, several numerical simulation models for coal have been proposed (Wu et al., 2010; Peng et al., 2014b).

Gas flow regimes in shales significantly affect mass transfer thus it affects intrinsic permeability change and in return, a change in intrinsic permeability will also significantly influence gas flow behaviours in different flow regions. Traditional multi-scale models for shale gas flow only consider complex gas flow regimes. Intrinsic permeability models rarely consider characteristics of gas flow in shales. To fully represent gas flow in shales, considering the mutual influence of flow regimes and intrinsic permeability would improve gas production prediction. In this paper, a multi-scale numerical simulation model with mutual influence was proposed. To achieve this, several gas flow equations of different flow regimes as well as intrinsic permeability model were developed and coupled with a deformation equation controlling deformation of shale reservoir included. Using experimental data, the intrinsic permeability model was first verified. Then, behaviours of gas flow and apparent permeability in shales during shale gas production were studied. Finally, impacts of several key factors on shale gas production were analysed.

2. Conceptual model

2.1. Multi-scale model

Due to the diversity in minerals and wide range of pore sizes in shales, the gas flow in shales is a combination of different controlling processes as shown in Fig. 1. Once gas production commences, flow behaviours in pores with different sizes occur differently: (a) the gas initially adsorbed on the surfaces of kerogen (or clay minerals) pores desorbs almost immediately; (b) gas diffuses from organic pores into inorganic pores; (c) gas in inorganic pores flows into natural fractures; (d) gas in natural fractures flows into hydraulic fractures then to production well. According to the Knudsen number, these gas flow behaviours in reservoir can be described in several flow regimes: (a) gas flow regime in kerogen is diffusion; (b) gas flow regime in inorganic pores networks is slip flow; and (c) gas flow regime in natural fractures is Darcy flow (Javadpour et al., 2007).

In shales, these flow regimes sequentially dominate shale gas

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