Fuel 215 (2018) 46–56

Contents lists available at ScienceDirect

Fuel

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

Full Length Article

Evolution of shale apparent permeability under variable boundary conditions

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ARTICLE INFO

Keywords:
Shale gas flow
Geomechanical effect
Adsorption-induced strain
Flow regime

ABSTRACT

In this study, a general shale apparent permeability model under the influence of gas sorption was derived based on the theory of poroelasticity. Unlike previous models, the impact of gas adsorption-induced swelling strain was treated as a local phenomenon. This was achieved through the introduction of an internal strain. The internal strain is directionally proportional to the swelling strain. The proportional coefficient has a clear physical meaning and is defined as the ratio of the Langmuir strain constant for shale matrix to the product of the Langmuir strain constant for shale bulk and the shale porosity. The general permeability model was degenerated into a set of specific shale permeability models under common experimental conditions: (1) constant effective stress; (2) constant pore pressure; and (3) constant confining stress. Nineteen groups of experimental data in the literature were used to verify the validity of those models: three for the boundary condition of constant effective stress; five for the condition of constant pore pressure; and eleven for the boundary condition of constant confining stress. The successful matches of these nineteen groups of experimental data with our model results demonstrate the validity of our general shale permeability. These models can be used to analyze the experimental observations of shale permeability under a spectrum of boundary conditions from constant confining stress to constant pore pressure.

1. Introduction

The production behaviour of shale gas has an inherent link with the complicated variation of shale permeability. Shale gas reservoir is a typical tight formation in which the gas transport involves complex mechanisms depending on the flow regime and porous formation conditions [1]. Therefore, the simple Darcy's law yields significant inaccurate values of permeability.

The feature of shale gas flow is the co-existence of several flow regimes such as Darcy flow, slip flow and diffusion [2]. The gas permeability is called as apparent permeability which is significantly affected by both pore structure and flow regimes. Great efforts have been made to investigate the apparent permeability of shale. To classify different flow regimes, the Knudsen number, a ratio of the mean-free-path of gas to the pore diameter, is used to distinguish these regimes ranging from the free-molecule flow to the continuum flow [3]. Javadpour et al. [1] analyzed characteristics of Knudsen diffusion and slip flow, and presented the improved Darcy-type formation of shale gas flow in nanopores. Civan et al. [4] presented the model characterized by the Knudsen number. That model can accommodate a wide range of fundamental flow mechanisms depending on the prevailing flow conditions. Moghadam and Chalaturnyk [5] expanded the Klinkenberg's slippage equation to low permeability porous media. Guo et al. [6] proposed an apparent permeability model for nanopores and that model was verified by experimental data from nanotubes experiments. The apparent permeability (k_{app}) is the resultant of an intrinsic permeability (k_∞) and a correlation coefficient (usually presented as k_g). The above studies only focused on the correlation coefficient (k_g) but assumed the intrinsic permeability (k_∞) as a constant. However, this assumption is not acceptable during gas depletion because the intrinsic permeability may sharply change.

The intrinsic permeability is a function of pore diameter and porosity of rocks [7,8]. During gas depletion, the geomechanical deformation of shale can dramatically affect the pore diameter so that the

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https://doi.org/10.1016/j.fuel.2017.11.024
Received 23 November 2016; Received in revised form 3 November 2017; Accepted 7 November 2017

intrinsic permeability is often observed as a pressure-dependent variable. The field data of pressure and gas production rate demonstrated the evidence of pressure-dependent permeability in Horn River and Haynesville shale [9]. In laboratory, it was observed that the intrinsic permeability decreases with effective stress [10–14]. The comparison between Klinkenberg effect and geomechanical effect on permeability was investigated in laboratory as well. When pore pressure exceeds 500 psi (around 3.5 MPa) the Klinkenberg effect would not significantly affect permeability [15]. Effective stress, ranging from 0 MPa to 100 MPa, always significantly affects permeability [10,11]. In addition, the variation in pore size also affects the value of Knudsen number and further influences the magnitudes of impact of gas flow regimes on permeability. Civan et al. [4] suggested that Knudsen number has a close relationship with intrinsic permeability and porosity which are determined by pore size [7,8,16].

In shale gas reservoirs, methane is stored in both free-phase and adsorbed-phase forms [17]. Due to the existence of organic matter and the large surface area of nanopores, the content of adsorbed-phase methane can be up to 20–80% [18,19]. Methane is able to adsorb in organic matters which could induce a swelling strain of shale. The volumetric swelling strain of shale due to CH_4 adsorption is around 0.1% at 10 MPa [20]. Like shale, coal could absorb methane but has a larger swelling strain due to gas adsorption. The swelling strain of coal due to gas adsorption can reach at 0.5% at 6.9 MPa (the volumetric swelling strain due to gas adsorption could be 1.5%) [21]. Adsorption-induced swelling strain significantly affects pore aperture and intrinsic permeability of coal [22–26]. Although the adsorption-induced swelling strain in shale is low, it could also affect intrinsic permeability because pore size of shale is low as well [27]. The pore size in shale usually ranges from 5 to 1000 nm [7,28], and is much less than that of other rocks, such as sandstone [7].

Several models were proposed to account for the impact of gas adsorption layers on the intrinsic permeability [27,29,30]. Xiong et al. [29] established a model for bundles of circular cross section tubes, considering the effect of the gas adsorption layer. In that model, the pore was regarded as a planar surface and the effective radius changed linearly with the Langmuir isotherm. Sigal [30] modified the model to account for the loss of pore volume due to gas adsorption. Wang et al. [27] derived a model for both gas transport in nano-capillary tube and nanopores. Gas adsorptions obeying both Langmuir and BET isotherm were incorporated. These models only considered the situation that an adsorption layer resides on surfaces of organic tubes at the nano-scale. In this case, the impact of gas adsorption on apparent permeability disappears when the tube size exceeds 10 nm [29]. In addition, the percentage of organic pores in shale is usually low, usually less than 20% [15]. Gas shale in natural has matrix and fracture systems [15,31,32]. The natural fracture system also provides an essential and effective flow path for shale gas and permeability of natural fracture significantly affects shale gas production [33].

In this study, the effect of gas adsorption on the apparent permeability of natural fracture system was mainly discussed. Although gas adsorption occurs in organic matters, this gas adsorption could induce the volumetric strain of the whole shale bulk [20]. In this case, the natural fracture as one part of a shale bulk would also deform due to the gas adsorption in organic matters. The impact of gas adsorption on apparent permeability was illustrated, and a method of using experiment data to calculate the magnitude of this impact was proposed. First, a conceptual model was used to illustrate the importance of gas adsorption for the change of intrinsic permeability. Secondly, according to poroelastic constitutive law and our understanding of the internal strain, a general pressure-dependent apparent permeability model with the impact of gas adsorption was developed. In order to analyze the impact of the gas adsorption on apparent permeability, lastly, 19 groups of experimental data under variable conditions were analyzed and compared with models built in this study.

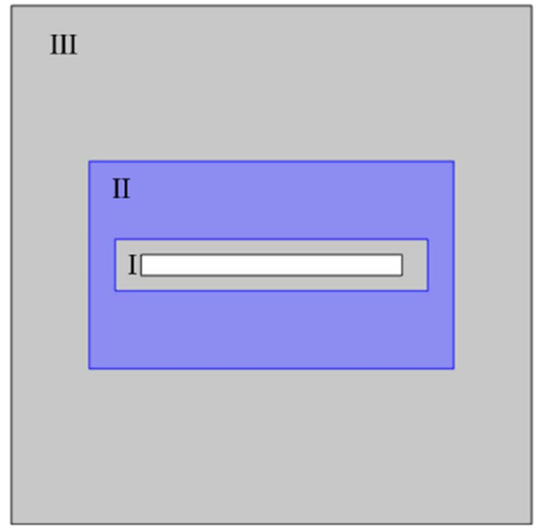

Fig. 1. Illustration of a conceptual geometry of the matrix-fracture system in shale (The matrix block is divided into three regions with different absorption capacities: Region I, Region II and Region III; the blue area represents the region with organic matters).

2. Conceptual understanding of adsorption-induced swelling impact

In this section, a conceptual geometry of the matrix-fracture system in shale is built to illustrate the importance of the gas adsorption for the variation in intrinsic permeability. The gas adsorption in matrix block could force the matrix block to deform towards the fracture. The matrix block in shale consists of different minerals with quite different absorption capacities. In order to represent this feature of shale, as shown in Fig. 1, the matrix block is divided into three regions with different absorption capacities. To simplify the question, it is assumed that only Langmuir strain constants in these regions are different. For the first scenario, the region II contains organic matters which absorb gas while other two regions do not contain organic matters. For the second scenario, the region III contains organic matters while other two regions do not contain organic matters.

The gas transport between fractures and matrix blocks is subject to the mass conservation law for an ideal gas, as shown in Eq. (1) and the deformation equation of the matrix block is shown as Eq. (2). The intrinsic permeability can be calculated by the fracture aperture, as shown in Eq. (3). The parameters of this numerical simulation are listed in Table 1. All the values are selected within the range reported in academic papers [16,34–36].

$$\left[\phi_n + \frac{\rho_s p_a V_{Ln} P_{Ln}}{(p_n + P_{Ln})^2}\right]\frac{\partial p_n}{\partial t} + p_n\frac{\partial \phi_n}{\partial t} - \nabla\cdot\left(\frac{k_{mn}}{\mu}p_n\nabla p_n\right) = 0 \tag{1}$$

$$Gu_{i,kk} + \frac{G}{1-2v}u_{k,ki} - \alpha p_{,i} - K\varepsilon_{s,i} + f_i = 0 \tag{2}$$

$$\frac{k_{in}}{k_{in0}} = \left(1 + \frac{\Delta b}{b_0}\right)^3 \tag{3}$$

where ϕ is porosity, ρ_s is shale density, p_a is atmosphere pressure, V_L and P_L are two Langmuir constants, p is pressure, k_m is the matrix permeability, μ is viscosity, and the subscript n indicates the index of matrix regions, α is the Biot's coefficients of shale, G is the shear modulus of shale, $G = E/2(1 + v)$, K is the bulk modulus of shale, $K = E/3(1 - 2v)$, E is the Young's modulus of shale, v is the Poisson's ratio of shale, ε_s is the gas adsorption-induced swelling strain, and f is the body force of shale, u is the displacement. k_{in} represents the intrinsic permeability of this conceptual geometry and b represents the aperture of fracture.

Applying Langmuir isotherm to get the gas adsorption-induced