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Dependence of gas shale fracture permeability on effective stress and reservoir pressure: Model match and insights

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HIGHLIGHTS

- A theoretical correlation between shale permeability and effective stress is derived.
- The model is capable of matching the experimental data for different gas shales.
- The correlation between fracture compressibility and shale properties is discussed.
- The correlation between shale permeability and reservoir pressure is derived.

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ABSTRACT

Although permeability data for different gas shales have been reported previously and attempts have been made to match permeability with empirical correlations, theoretical studies of shale permeability modelling are lacking. In this work, the correlation between fracture permeability and effective stress is established for gas shales through theoretical derivation. This model is able to match the permeability data for different gas shales. The matching results for the gas shale studied show that the model coefficient, fracture compressibility, which decreases as initial shale permeability increases, is strongly affected by the flow directions and varies with the shale's mineralogical composition. Furthermore, the correlation between fracture permeability and reservoir pressure has also been established. Sensitivity study shows that fracture permeability may decrease significantly with the reservoir pressure drawdown. Moreover, the horizontal fracture permeability drop is found to be significantly affected by the Young's modulus' anisotropic ratio (E_h/E_v). The insights gained warrant further theoretical and experimental studies to evaluate shale fracture permeability.

1. Introduction

Gas shale has complex pore structures: two matrix systems of organic and inorganic matter, as well as both natural and hydraulic fracture systems [1–3]. The main pathway for fluid flow through shale is through the fracture network, despite its relatively low fracture porosity. Gas is transported through fractures by viscous flow governed by Darcy's law [1], which is a proportional relationship between the flow rate and the pressure gradient. Permeability is an important parameter in Darcy's law to represent the gas deliverability in porous media.

Some experiments have been conducted to measure shale permeability in different samples, and attempts have been made to fit or describe the experimental data with empirical correlations. Soeder [4] measured the porosity and permeability of eight Devonian gas shale samples from the Appalachian basin: seven core samples from Upper Devonian Age Huron shale and one core sample from Middle Devonian Age Marcellus shale. The gas porosities of the Huron shale samples were less than 0.2% due to the presence of petroleum, and the gas permeabilities were commonly less than 0.1 microdarcy (μD). However, the Marcellus shale core is free of the liquid phase, and has a gas porosity of approximately 10% and a surprisingly high permeability of 20 μD. The gas permeability of all samples was highly stress-dependent. The permeabilities of the Huron shales were measured under two net (effective) stress levels of 12.1 MPa and 20.7 MPa, and the permeability of the Marcellus shale was measured under two net stress levels of 20.7 MPa and 41.4 MPa. Therefore, the data illustrates the high stress dependency of shale permeability, but the limited data points do not

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reveal a correlation between shale permeability and effective stress. Moreover, the author used a sheet-type fracture structure to describe the fluid flow through the fractures in gas shale, and presented the correlation between fracture permeability and fracture aperture on the basis of the classic theory for idealized fractured reservoir rocks.

Ross and Bustin [5] reported porosity and permeability data for shale samples from different formations (Besa River, Muskwa, and Fort Simpson) in the Western Canada sedimentary basin. The permeabilities were less than 0.04 mD and commonly in the nanodarcy (nD) range for the entire sample suite. A poor correlation between porosity and permeability was found for most samples, except for siliceous lower black mudrock in the Besa River formation, which showed a log-linear profile. Bustin et al. [6] stated that the permeability of shales varied by several orders of magnitude with effective stress. Their measurements illustrated the exponential dependence of shale permeability on effective stress for Muskwa, Barnett and Ohio shale samples. In addition, shales rich in detrital quartz had higher porosity and permeability than shales rich in biogenic quartz. More experimental data of shale permeabilities are documented in [7].

Dong et al. [8] measured the permeability and porosity of Chinshui shale in Taiwan. The effective confining pressure applied in their experiments ranged from 3 to 120 MPa, which is much higher than in the aforementioned experiments. Dong et al.'s experiments confirmed the high stress sensitivity of shale permeability, which varied by two to three orders of magnitude in their shale samples. Although an exponential correlation was observed in Bustin et al.'s findings with an effective confining pressure of up to 40 MPa [6], the correlation in Dong et al.'s work deviated in the larger range of effective confining pressure up to 120 MPa [8]. They used both power law and exponential relationships to fit the experimental data, with the power law correlation being more favourable.

Although the high dependence of shale permeability on effective stress has been confirmed by several experiments, and empirical models have been applied to describe the experimental data, there is still a shortage of theoretical studies on shale permeability modelling. Theoretical permeability models for idealized fractured reservoirs are available [9–11], but they cannot be directly applied to gas shales due to the following unique shale characteristics: the structure of the shale fracture network is irregular [12], the shale fractures have poor connectivity [12], the shale fracture permeability is sensitive to stress [4], and the fracture permeability may change significantly during hydraulic fracturing when natural fractures become hydraulic fractures. Therefore, a fundamental theoretical study on fracture permeability in gas shales is necessary.

This study consists of three main parts. First, the fracture permeability model is derived on the basis of the characteristics of gas shale fractures. Second, the model is applied to match the permeability data for a number of gas shales, and the characteristics of the model coefficient are investigated. Third, we discuss some important issues related to fracture permeability of gas shales that lack experimental evidence.

2. Derivation of fracture permeability correlation for gas shale

The fractures in gas shale are irregular (see Fig. 1, the fractures in the Barnett shale from [13]) and some fractures are mineralized with calcite cement or pyrite [5]. Therefore, it is difficult to simplify gas shale fractures to an idealized fracture network with simple geometry. This section derives the fracture permeability correlation for gas shales.

2.1. Fluid flow through parallel straight fractures

The rate of the fluid flow through a single fracture (q_1), as shown in Fig. 2a, can be calculated by Poiseuille's equation [9]:

$$q_1 = \frac{b^3 l}{12\mu}\frac{\Delta p}{L} \tag{1}$$

where b is the fracture aperture, l is the length of fracture, μ is the fluid viscosity, Δp is the pressure difference between the flow-in end and the flow-out end, and L is the length of the flow path.

Assuming the fracture aperture is identical for all the fractures (or using an equivalent fracture aperture to avoid the effect of aperture heterogeneity), the flow through n parallel fractures across a section A, as shown in Fig. 2b, is the sum of each individual fracture:

$$q_n = \frac{b^3\sum_{i=1}^{i=n} l_i}{12\mu}\frac{\Delta p}{L} \tag{2}$$

Assume the fluid flow through these parallel fractures is also governed by Darcy's law:

$$q = A\frac{k}{\mu}\frac{\Delta p}{L} \tag{3}$$

where q is the flow rate, A is the cross-section area, and k is the permeability of fractures.

Since the mass flow rates calculated by these two basic principles are identical ($q_n = q$), then we have:

$$k = \frac{\sum_{i=1}^{i=n} l_i}{A}\frac{b^3}{12} = P_{22}\frac{b^3}{12} \tag{4}$$

where P_{22} is the fracture intensity, one type of area measure of fracture intensity as shown in Table 1.

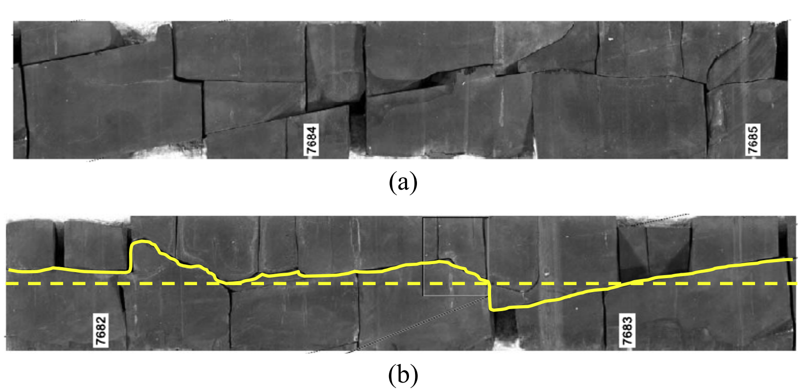

Fig. 1. Fractures in two Barnett shale core samples.