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Rate dependency of permeability in tight rocks

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A B S T R A C T

Matrix permeability of tight rocks is a challenging parameter to measure. The gas permeability measurements of low-permeability rocks are sensitive to pressure, effective stress, temperature, and testing technique. However, the influence of gas flow rate on permeability measurements of tight rocks is unknown.

In this work, steady-state gas permeability experiments are conducted on four shale and siltstone samples using methane and nitrogen as flowing fluid. The gas permeability is measured at several flow rates, while mean pressure and mean effective stress are held constant. The measurements are repeated at several mean pressure values. The tests are designed to study the influence of mean pressure as well as flow rate on gas permeability. After the gas permeability measurements, the samples are saturated with water to measure water permeability. Subsequently, the samples are sheared in a triaxial cell and similar gas and water permeability tests are repeated to compare the permeability behavior before and after failure. The results indicate strong rate sensitivity in permeability of tight rocks. Measured permeability is observed to rise as flow rate increases and reaches a constant value at higher rates. Permeability of the failed samples shows a similar behavior, although with higher permeability values. The rate dependency of gas permeability seems to follow a trend, similar to what is reported in the literature as the transition between pre-laminar and laminar flow regimes. Based on the experimental results, a discussion is provided on the rate at which the transition between pre-laminar and laminar flow occurs. Finally, by combining the theories on rate dependent flow regimes and pressure dependent (Knudsen number) flow regimes, a more complete picture of gas permeability in porous media is proposed.

1. Introduction

Permeability is one of the most important parameters that control production. Permeability is defined for a rock, according to a steady-state flow of fluids (liquid) through a porous media. Permeability measurement in ultra-low permeability shale rocks is challenging and does not follow similar physics as of conventional rocks. Gas permeability of rocks varies significantly with the testing pressure, temperature, and effective stress. There has been significant theoretical (Zhang et al., 2015a), experimental (Zhang et al., 2015b), and numerical (Li and Sultan, 2016) work to understand the influence of pressure and effective stress on gas apparent permeability. Based on the observations, an increase in gas pressure and in effective stress leads to a decrease in apparent permeability (Moghadam and Chalatyrnyk, 2016). The influence of temperature however, has not been studied as widely. An increase in temperature has been observed to decrease the apparent permeability (Sinha et al., 2012; Moghadam, 2016). Civan (2008) proposed two different models to explain the loss of permeability due to thermal compaction in diatomite. The models have not been confirmed for shales or siltstones.

Theoretical and analytical investigations into the influence of pressure (or Knudsen number) on shale permeability have been done by several authors (Moghadam and Chalaturnyk, 2014; Sakhaee-Pour, and Bryant, 2012; Javadpour et al., 2007; Ziarani and Aguilera, 2012; Roy et al., 2003). Moghadam and Chalaturnyk (2014) proposed an expansion to Klinkenberg's equation for slip flow by changing the zero velocity gradient assumption in Klinkenberg's original work. The proposed equation is expected to predict gas permeability in shales flowing under slip and early transition flow regime. Laboratory results are used to match the equation and provide a range for parameters. Ziarani and Aguilera (2012) investigated a second-order Knudsen correlation to calculate gas permeability and concluded that Klinkenberg's correlation underestimates the permeability enhancement due to slip flow.

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Darabi et al. (2012) proposed an apparent permeability function (APF) assuming Knudsen diffusion and slip flow are the dominant flow regimes in shale pores. Rahmanian et al. (2013) assumed that flow in shales is composed of a viscous flow and a free molecular flow component. Singh et al. (2014) proposed an equation for apparent permeability based on Darcy and Knudsen flow. Nazari Moghadam and Jamiolahmady (2016) applied first-order and second-order slip models to Navier-Stokes equations to capture the gas permeability enhancement due to slippage. They concluded that at high Knudsen numbers the Klinkenberg equation overestimates the absolute permeability. Ye et al. (2015) proposed a unified permeability model applicable to gas flow under different flow regimes. The proposed equations for apparent permeability tend to come with a myriad of parameters (typically empirical) that should be evaluated using laboratory experiments. Difficulties arise when some parameters cannot be directly measured in the lab. Additionally, relating the apparent permeability to Knudsen number requires pore size measurements which are not common and change with test conditions such as mean effective stress. Ideally, apparent permeability should be related to more tangible parameters such as pore pressure and liquid permeability.

In addition to the extensive theoretical studies, several experimental investigations of shale permeability has been conducted (Moghadam and Chalaturnyk, 2015; Heller and Zoback, 2013; Bustin et al., 2008; Ghanizadeh et al., 2013, 2014; Heller et al., 2014). There are a few experimental techniques to measure the permeability of a core. Steady-state, pulse-decay, profile permeability, and crushed rock permeability are some of the most popular methods. There is no consistency between these methods and each could yield a different value for permeability sometimes orders of magnitude different (Ghanizadeh et al., 2015; Rushing et al., 2004; Sinha et al., 2012; Clarkson et al., 2012). Typically, profile permeability returns a higher permeability value at the same test conditions compared to pulse-decay method and both methods measure higher permeability values than crushed rock permeability (Ghanizadeh et al., 2015). Crushed rock and profile permeability measurements are conducted on samples with no confining stress. Effective stress has a dominant effect on the permeability of rocks (Heller et al., 2014; Moghadam and Chalaturnyk, 2015) therefore the permeability measured at no confining stress is not a representation of reservoir condition. Pulse-decay method is a transient technique that creates a pressure pulse across the core. Permeability is then derived indirectly from the pressure decay with time typically using the solution proposed by Brace et al. (1968). The tests can be done at various pore pressures and confining stresses in a timely manner. Deriving permeability from transient pressure response needs further assumptions and parameters that add a layer of uncertainty when dealing with shale rocks. There have been efforts in the literature to enhance the accuracy of the transient permeability measurement techniques (Cao et al., 2016). The physics of flow are not well understood in shales and therefore the number of assumptions should be minimized. Additionally, in pulse-decay method the pressure across the sample changes with time. This causes the flow rate through the sample to change and therefore the potential rate dependency of permeability is not captured. The permeability is typically assumed to be independent of flow rate as the original Darcy equation assumes laminar flow regime. This assumption does not stand for gas flowing at high rate through a high permeability medium, where inertial forces cause permeability to decrease with rate. This phenomenon has been studied extensively, regarding high rate gas wells and fracture flow (Huang and Ayoub, 2008; Lai et al., 2012). For the case of very low flow rates, typical in the matrix of tight rocks, there are very few studies concerning the influence of flow rate on permeability (Gavin, 2004). Moghadam and Chalaturnyk (2015) conducted steady-state gas permeability experiments on low permeability samples. They studied the influence of pressure, effective stress, temperature, gas type, and rate on apparent permeability of gas. Their results indicate that permeability of tight rocks is sensitive to gas flow rate.

In this work, steady-state gas permeability measurements are done to study the effect of flow rate on apparent permeability. For each test, the mean pressure is maintained at a constant value while the gas rate is increased across the sample by increasing the pressure difference. The pressure difference and flow rate after equilibrium is used to calculate the apparent permeability using the Darcy equation. Based on the results, a model is proposed to predict the influence of flow rate on apparent permeability. The rate dependent flow regimes are comprised of pre-laminar, laminar, and inertial flow (Kutilek, 1972; Basak, 1977). At low rates, during the pre-laminar flow, permeability is observed to increase with rate until laminar flow regime is reached. Based on the experimental results, the transition between pre-laminar and laminar flow regimes is investigated.

Fundamentally, permeability is defined for steady-state flow through porous media. Therefore, the permeability results in this work come directly from definition and no assumption on flow regime is needed. Tests can be done at various mean pore pressures, confining stresses, and flow rates. Using steady-state method to measure shale permeability takes a longer time compared to other testing techniques and therefore is not popular. In this work however, we have used the steady-state method due to the higher flexibility in testing conditions and more fundamentally accurate results.

2. Laboratory experiments

2.1. Sample description

Steady-state gas permeability tests were conducted on four dry shale/siltstone samples, one from the Clearwater Formation in Alberta, Canada, and three from the Montney formation in British Columbia, Canada. Nitrogen was used as the flowing fluid for the Clearwater sample, and methane for the Montney samples, all at room temperature (25 °C). Table 1 shows a summary of sample dimensions and experimental conditions. The size of the Montney samples was chosen to be relatively small (1.2 cm in length) in order to save time when running steady-state permeability tests. Table 2 presents the mineralogy of the Montney samples. The Montney 10D and 8H samples are mainly comprised of silicates (quartz) while the Montney 17O sample has significant amounts of carbonates (dolomite). All samples had relatively low clay content (8–16%). Clearwater formation is a caprock shale and does not contain organic matter. The organic content of the Montney samples are below 2% also presented in Table 2. The porosity of the samples is measured using mercury injection method through a commercial lab. Samples were cored from bigger specimens and ground to ensure that top and bottom surfaces were parallel. The Clearwater sample was cored perpendicular to the bedding and the Montney samples were drilled parallel to the bedding planes. While all samples were largely intact, hairline cracks were noticed on their surfaces. None of these cracks seemed to go through the samples.

2.2. Laboratory setup

The samples are placed in a triaxial cell with a Viton membrane separating them from the confining fluid. The confining fluid (Silicon oil) exerts isotropic stress on the samples. A ram sits at the top of the sample to apply axial stress. Confining and axial stress are