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Characterization of anisotropy in the permeability of organic-rich shales

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ABSTRACT

Accurate determination of permeability is essential and challenging in organic-rich shales due to the tight and heterogeneous nature of shale formations, the presence of lamination as well as induced or natural fractures and the sensitivity of fracture permeability to stress. The tight nature of shale formation makes the traditional steady-state method not to be practical. Therefore, unsteady state methods such as pulse decay or crushed-sample have been practiced for shales. However, the pulse decay method can be still time consuming and the crushed-sample method is size-dependent as our numerical simulations show. As an alternative method, the results of complex transient method are presented. Moreover, the presence of lamination and fractures causes directional dependency of permeability. To characterize this type of anisotropy, three-plug method is usually applied. However, the variation of permeability with location causes this method to be unreliable in heterogeneous formations. Similarly, the presence of artificial micro-fractures affects the reliability of the permeability measurement in shales. Using variety of methods to measure permeability, the effects of these anisotropic and heterogeneous features under stress are discussed.

1. Introduction

Well-developed laminations originate from quiet and deep anaerobic depositional environment (O'Brien and Slatt, 1990). Lamination in shale reservoirs is usually attributed to the alignment of platy particles such as clays. The natural tendency of clay particles to be aligned in parallel orientation reduces the tortuosity in the direction of particle alignment compared to the tortuosity in the perpendicular direction to the clay particle alignment. Ten orders of magnitude difference in the permeability of mudstones at a given porosity was reported by Dewhurst et al. (1999). This significant variation in permeability at specific porosity was attributed to the grain size variations in the mudstones. The coarser-grain mudstones are more permeable but the difference diminished at higher effective stresses due to the collapse of larger pores. Consolidation tests on several artificial clays by Clennell et al. (1999) showed that uniaxial consolidation alone produces little anisotropy which is much lower than the predicted values by the clay alignment models. The discrepancy was attributed to the particle clustering and irregularities in particle packing. Although clay alignment can be also source of anisotropy in organic-rich shales, it should be considered that organic-rich shales usually are not dominated by clay (Hart et al., 2013), thus their anisotropic features can be different from the seal shales with high clay content. Micro-fractures are abundant in organic-rich shales. Micro-fractures can be created during hydrocarbon generation and expulsion (Berg and Gangi, 1999; Lash and Engelder, 2005; Lewan and Birdwell, 2013; Al Duhailan et al., 2013). The lenticular shape of kerogen has an impact on the shape of created micro-fracture and this lenticular distribution of kerogen can cause anisotropy in wave velocity (Vernik and Milovac, 2011). Moreover, regional structural activities can create natural fractures (Gudmundsson, 2011; Fossen, 2010) which are not necessarily aligned with the current maximum horizontal direction (Laubach et al., 2004).

On the other hand, fractures can be artificially introduced to shale samples as a result of the stress release during the coring; core transfer and core plug preparation for laboratory studies. Shales can be fractured in water due to capillary suction of water causing gas entrapment and finally tensile fracturing of the shale sample (Schmitt et al., 1994; Mitchell, 2001). Significant anisotropy in the illite-rich shale of Wilcox formation was reported at low effective stresses (Kwon et al., 2004). Permeability became increasingly isotropic with the increase in the effective stress. This behavior was attributed to the closure of crack-like voids parallel to bedding with stress. Bolton et al. (2000) observed permeability anisotropy in fine-grained sediments that did not show particle alignment using SEM analysis. The significant anisotropy was attributed to the parallel micro-fractures based on mercury-

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intrusion porosimetry data. It is critical to distinguish natural fractures from the induced one as the presence of fractures and heterogeneity can have significant impact on the laboratory evaluation of permeability data (Kamath et al., 1992; Honarpour et al., 1995; Suarez-Rivera et al., 2012; Sinha et al., 2012; Cui et al., 2009). Fractographic techniques are useful to distinguish between natural fractures and the coring or handling-induced fractures (Kulander et al., 1979). Horizontal natural fractures often show the indications of past tectonic activity. The frictional movement of fracture surfaces causes directional dependency of surface roughness called slickenside. Moreover, there is often secondary fibrous or non-fibrous mineral growth. Vertical natural fractures are very uncommon in conventional coring since there is low possibility of drilling widely-spaced vertical fractures in a vertical wellbore. Handling induced fractures usually indicate a powder zone at the point of impact on the outer core surface.

The sensitivity of fractured medium in porous media is important as discussed by Best and Katsube (1995), Walsh (1981), Dewhurst et al. (1999), Bolton et al. (2000), Kwon et al. (2004), Gudmundsson (2011), Cho et al. (2013), Honarpour et al. (2012), Bedayat and Taleghani (2012) and Bedayat and Dahi Taleghani (2015). This stress sensitivity is even more critical in organic-rich shales since the production from such tight formation totally depends on massive hydraulic fracturing. Classically, a propping agent such as sand has been used to avoid fracture closure in hydraulic fracturing (Clark, 1949). Similarly in shale reservoirs, closure of micro-fractures without proppants has been a concern (Nguyen et al., 2013). On the other hand, equal or better performance with low-proppant concentration (waterfracs) compared to classical fracturing in tight formations was reported by Mayerhofer et al. (1997). This phenomenon can be attributed to the fracture shear displacement (Fredd et al., 2001) in a rough fracture and the complex fracture network that a low-viscosity fluid can create. However, one should consider that water damage to matrix and fracture can be an issue in shale reservoirs (Bertoncello et al., 2014) but this issue is not discussed here since the experiments are conducted with gas.

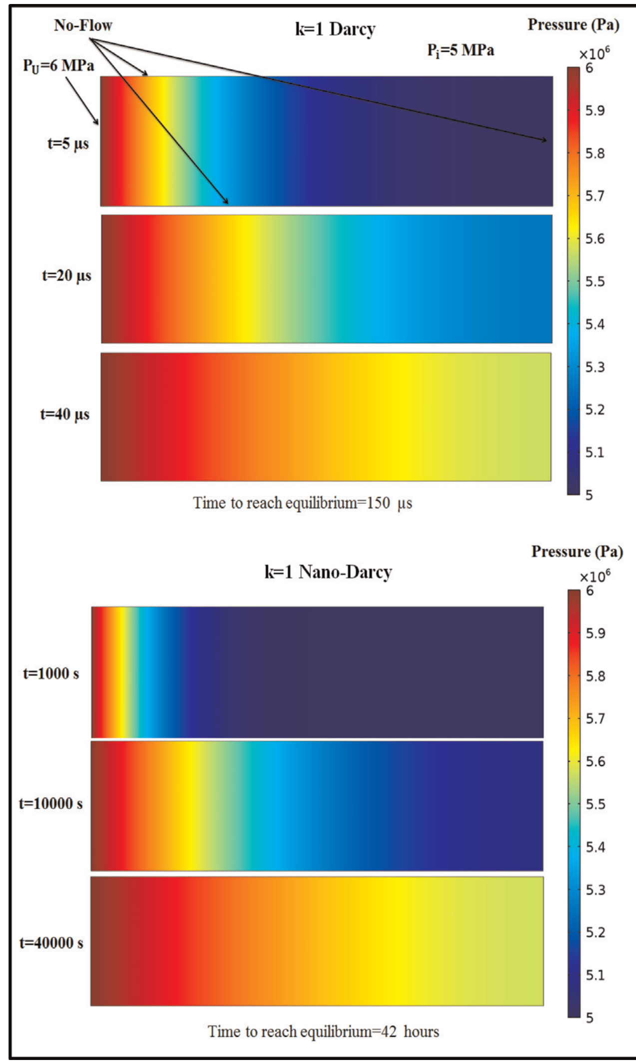

Fig. 1. Comparing the time required to saturate a sample of Darcy permeability with the sample of nano-Darcy permeability.

2. Theory and the experimental procedure for permeability measurement

Shale reservoirs have extremely low permeability which make the permeability measurement challenging. For instance, the time to saturate a shale sample is significantly higher than the time required saturating a conventional core sample as simulated in Fig. 1. Fluid flow in core samples is simulated using COMSOL Multiphysics in which the transient pressure diffusion equations are numerically solved using finite element method. The simulation results show that it takes 42 h to increase the pore pressure of a 1 nD (nano-Darcy) sample from 5 MPa to 6 MPa while the sample of 1 D (Darcy) permeability takes 150 μs to apply similar pressure increase. Therefore, several other methods besides the conventional steady state method have been developed to address the ultra-low permeability measurement such as the permeability measurement in shale reservoirs. In this section, a review of these methods and their simulation are presented.

2.1. Steady state method

Steady state method is the routine method to measure permeability of conventional core samples. In steady state method, fluid flows through core cross-sectional area as shown in Fig. 2. Pressure loss along the core is measured to calculate permeability according to Darcy's law.

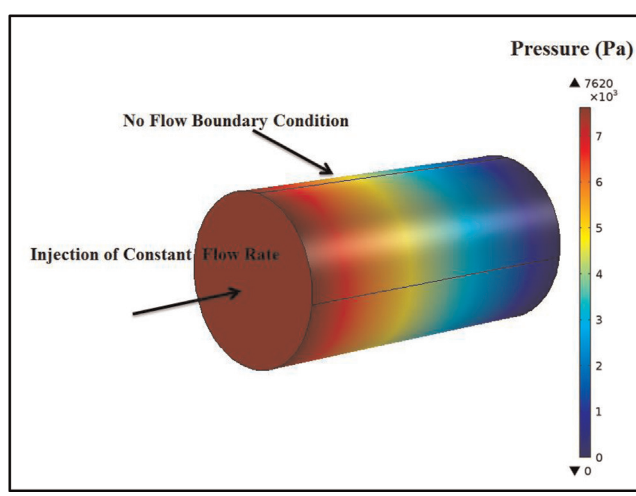

Fig. 2. Configuration of permeability measurement in steady state method.

$$k = \frac{-q\mu L}{A\,\Delta P} \tag{1}$$

where "k" is the permeability, "q" is the flow rate, μ is the fluid viscosity, "L" is the length of the core, "A" is the cross-sectional