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Analytical modelling of hysteretic constitutive relations governing spontaneous imbibition of fracturing fluid in shale

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ABSTRACT

Understanding spontaneous imbibition of fracturing fluid in shale is critical for hydraulic fracturing design and optimization. In this paper, we present an analytical model for spontaneous imbibition including a hysteretic relative permeability-saturation-capillary pressure (*k-S-P*) relation and evaluate the relevance of hysteresis effect when modelling fracturing fluid imbibition. In the hysteretic formulations, capillary pressure and relative permeability depend not only on the current saturation but also on the history of saturation in the invaded zone. Herein, we concentrate on fracturing fluid imbibition into shale matrix during shut-in time after refracture treatment, which is driven by the strong capillary forces present in the tight matrix. We demonstrate the importance of accounting for the hysteresis in capillary pressure and relative permeability for predicting the imbibed volume of a fracturing fluid. For a problem that involves drainage and imbibition cycles, a hysteretic *k-S-P* relation is required to accurately assess the distribution of fluid saturation in the invaded zone. We also demonstrate that although the difference in viscosity between the fracturing fluid and gas is large, the viscosity of the gas cannot be neglected in modelling fracturing fluid imbibition in shale. The results of this investigation are expected to provide a better understanding of fracturing fluid imbibition in shale.

1. Introduction

Shale gas, with its reputation as an efficient and environmentally friendly fuel, is becoming an increasingly promising alternative energy resource (Siirola, 2014). Due to the ultra-low permeability of shale gas reservoirs, hydrocarbon extraction is typically accomplished by multi-stage hydraulic fracturing (Wang et al., 2014), which involves the high-pressure injection of a mixture of water, proppant, and chemical modifiers deep underground to break up shale rocks and release gas. After injection, the well is shut-in for days to weeks (Fichter et al., 2009). Then, the injected fluid is recovered in a flow-back operation. Field observations indicate that a significant portion of fracturing water remains unrecovered and only a small fraction of injected fluid, on the order of 5–50% (King, 2012), can be recovered during the clean-up phase. This low recovery has led to both technical and environmental issues and has been an area of intense research over the last few years (Birdsell et al., 2015a). Spontaneous imbibition of fracturing fluid driven by capillary pressure is known as the primary mechanism for fracturing fluid loss and low water recovery during and after the fracturing operation (Ghanbari and Dehghanpour, 2015). Capillary pressure is a function of rock wettability, pore radius and interfacial tension, which controls spontaneous imbibition in reservoir rocks (Cai et al., 2010, 2012; Takahashi and Kovscek, 2010; Zhou et al., 2002). Water-wet shale exhibits a strong capillary force due to its narrow pore radius. In addition, fractured shale reservoirs can contain networks of intersecting fractures ranging from dozens of meters to several hundred meters in length and potentially offer large amounts of volume and surface area. Because of these fractures, unsaturated matrix imbibes substantial amounts of water during the shut-in period and traps the majority of the water by capillary action (Civan, 2014). Other possible mechanisms that are considered responsible for fracturing fluid loss include osmotic flow, hydration of clay minerals and creation of micro-fractures (Dehghanpour et al., 2013; Xu and Dehghanpour, 2014). In this work, we focus primarily on the fracturing fluid imbibition driven by capillary pressure and reserve the investigation of osmotic flow and hydration of clay minerals for future work.

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Numerous simulations of capillary-dominated imbibition in unsaturated shale have been carried out using a multiphase extension of Darcy law and relative permeability-saturation-capillary pressure (*k-S-P*) relations. However, most of them treat *k-S-P* relation in a simplified manner, namely using a single *k-S-P* relation. It is assumed that the *k-S-P* relation is non-hysteretic the capillary pressure and relative permeability depend only on the local saturation at the current time. A pioneering work was presented by Birdsell et al. (Birdsell et al., 2015b), who used an analytical model with a hysteretic capillary pressure-saturation (*S-P*) relation to simulate water imbibition in partially saturated shale. The hysteresis effect refers to irreversibility. In multiphase flow, hysteresis manifests itself through the dependence of the relative permeability and capillary pressure on the saturation path and the saturation history (Dernaika et al., 2012). Thus, hysteretic *k-S-P* relations are important for making accurate predictions in situations involving drainage and imbibition cycles, such as waterflooding in the presence of free gas saturations, recovery from coning after a well is shut in, production of oil from a transition zone and contaminant flow (Braun and Holland, 1995; Killough, 1976).

For the simulation of fracturing fluid imbibition after the original fracturing treatment (shut-in period), non-hysteretic *k-S-P* relations are useful because all locations follow the main branch of the capillary pressure curve at all times. However, non-hysteretic *k-S-P* relations cannot handle more complex situations, such as fracturing fluid imbibition after a refracture treatment (shut-in period). Refracturing is not a new technique and has been applied for many years in tight rock and vertical wells. However, now, producers want to apply refracturing to shale gas wells suffering from low production due to ineffective initial stimulation or rapid production decline (Cafaro et al., 2016; Jacobs, 2014). In a low natural gas price environment, refracturing provides a cost-effective solution for revitalizing and extending the life of shale gas wells. For refracture treatment, fluid saturation in the invaded zone has undergone a cyclic process (after initial shut-in and production period). Thus, the use of a hysteretic *k-S-P* relation is necessary to simulate fracturing fluid imbibition after refracturing (shut-in period).

The common approach for modelling fracturing fluid imbibition is the use of numerical methods. However, an analytical solution for fracturing fluid imbibition including the hysteresis effect is needed because it provides physical insight and serves as a benchmark tool. Moreover, analytical solutions often act as building blocks for numerical methods themselves (Blunt et al., 1996).

The purpose of this paper is to develop a simple method for describing the hysteretic *k-S-P* relation and thereby provide an analytical model for modelling the spontaneous imbibition of fracturing fluid in shale. In the following sections, we first introduce the mathematical formulation of the hysteretic *k-S-P* relation. We then analytically solve the variable coefficient diffusion equation based on a known integral solution for two-phase flow in a porous medium. Next, we validate the analytical solutions by comparing the results with those obtained by numerical simulations. Finally, we present calculations of imbibed volumes for the cases of non-hysteretic and hysteretic *k-S-P* relations and for the assumption of infinite gas mobility (an inviscid non-wetting phase) and end with concluding remarks.

2. Governing equation

Four mechanisms of fluid imbibition in shale have been proposed in the literature, which are: 1) capillary action, 2) clay hydration, 3) osmotic flow and 4) creation of micro-fractures (Binazadeh et al., 2016; Lan et al., 2015). However, the latter three mechanisms are currently not well understood. In subsurface environment, shales can act as membranes (Marine and Fritz, 1981). The osmotic flow occurs when shale membranes separate the low-concentration fracturing fluid and the high-concentration strata water. Several studies (Fakcharoenphol et al., 2016; Wang and Rahman, 2016) investigated the effect of osmosis on fracturing fluid imbibition in shale. However, their studies are limited to single phase (water) system. The osmotic effect on multiphase flow is not well understood. Moreover, the osmotic flow is related to the membrane efficiency of mudrocks, which ranges from 0.0423 to 0.8912 (Fritz and Marine, 1983). However, to the best of our knowledge, we are not aware of any direct measurement of membrane efficiency made on samples from shale gas reservoirs at reservoir conditions. Moreover, although many publications have reported that micro-fractures can take up a significant amount of water, most of the studies have been carried out under atmospheric conditions. Roshan et al. (Roshan et al., 2015) found that under confining pressure the formation of micro-fractures by swelling is much slower than that under atmospheric pressure. Water adsorption by clay minerals involves complex physical-chemical processes. For shale media, the development of a hydraulic model including water adsorption is on-going. For these reasons, in this work we focus primarily on the fracturing fluid imbibition driven by capillary pressure and reserve the investigation of osmotic flow and clay hydration for future work.

With a negligible gravity effect, the mathematical-physical equation for one-dimensional horizontal, immiscible, incompressible, isothermal two-phase flow in a semi-infinite porous medium is (Bear, 2013)

$$\frac{q_t}{\varphi}\frac{df_w(S_w)}{dS_w}\frac{\partial S_w}{\partial x}-\frac{1}{\varphi}\frac{\partial}{\partial x}\left(D(S_w)\frac{\partial S_w}{\partial x}\right)+\frac{\partial S_w}{\partial t}=0 \tag{1}$$

where S_w is the wetting phase saturation, φ is the porosity, q_t is the total volumetric flow rate, m^3/s, f_w is the fractional flow function without the influence of capillary pressure and D is the diffusion coefficient, m^2/s. Henceforth, water is the wetting phase, and gas is the non-wetting phase. The functions f_w and D are defined as (Schmid and Geiger, 2012)

$$f_w(S_w)=\left(1+\frac{k_{rnw}\mu_w}{k_{rw}\mu_{nw}}\right)^{-1} \tag{2}$$

$$D(S_w)=-\frac{Kk_{rnw}k_{rw}}{\mu_w k_{rnw}+\mu_{nw}k_{rw}}\frac{dP_c(S_w)}{dS_w} \tag{3}$$

where K is the absolute permeability, m^2, μ_w is the viscosity of wetting phase, μ_{nw} is the viscosity of non-wetting phase, k_{rw} is the relative permeability of wetting phase, k_{rnw} is the relative permeability of non-wetting phase and P_c is the capillary pressure, Pa. During fracturing treatment, some imbibition can occur under forced conditions, but the duration of forced imbibition is likely to be much shorter than the duration of spontaneous imbibition (Birdsell et al., 2015b), which can last for days to weeks corresponding to the shut-in period. Therefore, this work is restricted to examining fracturing fluid imbibition during the shut-in period. Fig. 1 shows a schematic of a simplified multi-fractured horizontal well. The geometry of hydraulic fracture is assumed to be elliptical (Liu et al., 2015). The arrows indicate the direction of the imbibition. The red dashed box shows the study area, which covers a bi-wing hydraulic fracture. We assume that fracturing fluid migration during the shut-in period is controlled by counter-current spontaneous imbibition. In counter-current spontaneous imbibition, capillary pressure is the driving force, which draws in the wetting phase and