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Coupled thermo-hydro-chemical modeling of fracturing-fluid leakoff in hydraulically fractured shale gas reservoirs

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A R T I C L E I N F O

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A B S T R A C T

Once the low-temperature, high-pressure and low-salinity water contacts the shale matrix through the hydraulic fractures during the treatment of hydraulic fracturing, both mass and energy transfer occur due to the significant temperature, pressure, saturation and salinity gradients. Although, many leakoff models have been published, none of the models coupled the transient fluid flow modeling with heat transfer and chemical-potential equilibrium phenomena. In this paper, a coupled thermo-hydro-chemical (THC) model based on the derivation of non-isothermal chemical-potential equations from Gibbs' free energy is presented to simulate fluid/heat flow behaviors during the leakoff process of hydraulic fracturing. The THC model takes into account a two-phase flow and a triple-porosity medium, which includes hydraulic fractures, organic and inorganic shale matrix. The simulation of fluid flow and leakoff with the THC model accounts for all the important mass and heat transfer processes occurring in fractured shale system, including fluid transport driven by convection, adsorption and diffusion, and heat transport driven by thermal convection and conductivity. The dynamic temperature, pressure, saturation and salt concentration profiles within fractures and shale matrix are calculated, revealing a multi-field coupled invasion region of fracturing-fluids during the treatment of hydraulic fracturing. In sensitivity analyses, cases with different initial reservoir temperature, pressure, saturation and brine salinity are considered. The impacts of the temperature, pressure, saturation and salinity gradients between the shale formation and the pumped fluids on the well injection and leakoff volumes during the treatment of hydraulic fracturing are investigated. Results show that although hydraulic pressure is the most factor which affects the fracturing-fluid leakoff behavior, the combination of chemical-osmosis, thermal-osmosis and capillarity still has a non-negligible influence on the fracturing-fluid leakoff. This study provides a better understanding of the mass and heat transport mechanism of water-based fracturing-fluids in shale gas reservoirs.

1. Introduction

Shale gas is an unconventional resource that has huge reserves all over the world. Multistage hydraulic fracturing with slickwater (a typical Newtonian fluid, and the water ratio can be as high as 99.5%) has been proven to be the most effective technology for exploiting shale gas reservoirs currently available (Thompson et al., 2010). Although non-Newtonian fluids advancing in fractured porous media springs up more economically advantageous technologies for enhanced gas recovery (Longo and Federico, 2015). Several million gallons of slickwater are required to pumped into the target formation in a multistage hydraulic fracturing treatment of horizontal wells (Cipolla et al., 2009). However, most of the water pumped during the treatment is retained in the shale reservoir. In practice, it is common that only a small fraction of pumped water, typically 10–40%, can be recovered during the process of flowback for cleanup of the loaded fluid (Penny et al., 2006; Chekani et al., 2010; Cheng, 2012).

Water leaked into shale matrix is considered to be the major mechanism responsible for water retention (Roychaudhuri et al., 2011; Dehghanpour et al., 2012; Makhanov et al., 2012; Dehghanpour et al., 2013; Lan et al., 2014). The first possible process for water leaking into matrix is driven by hydraulic pressure difference between the hydraulic fracture and shale matrix. Various pressure dependent leakoff models were developed for fracture propagation simulation (Williams, 1970; Fan and Economides, 1995; Meyer and Jacot, 2000; Yew et al., 2000; Li et al., 2005). Besides the forced leakoff, spontaneous imbibition driven by capillary pressure is a widely reported effect that induce extra water invasion. A vast amount of experimental and numerical studies have been

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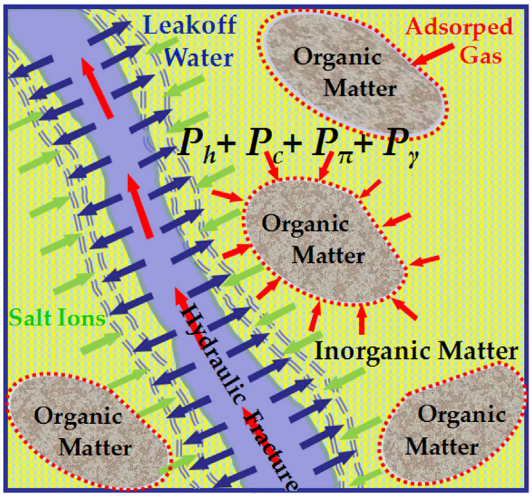

Fig. 1. Schematic of fluid interactions during the hydraulic, capillary, chemical-osmotic and thermo-osmotic processes.

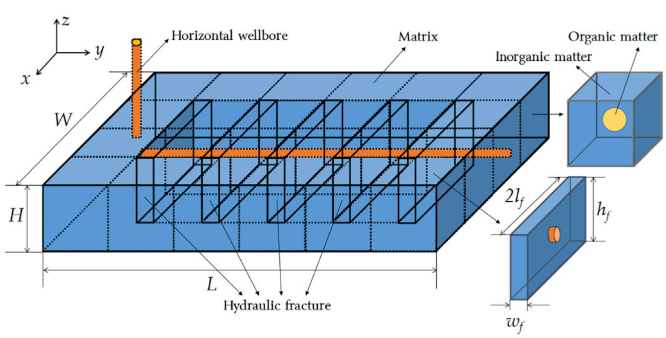

Fig. 2. Schematic diagram of the THC model.

conducted to investigate the spontaneous imbibition of water into shale matrix (Roychaudhuri et al., 2011; Michel et al., 2012; Jurus et al., 2013; Xu et al., 2015).

Recently, chemical osmosis has been proposed as a possible leakoff mechanism for the invasion of water-based fracturing-fluids in clay-rich sediments, such as shale (Fakcharoenphol et al., 2015; Wang et al., 2016; Li et al., 2016). Chemical osmosis is initially developed in drilling-fluid/shale interactions (Chenevert, 1970), because water flow in and out of shale formations plays a major role in the alteration of the physico-chemical and mechanical properties of a shale thus leading to wellbore instability problems (Al-Bazali et al., 2009). The osmotic water transport occurs when clay membrane separate different salinity fluids on both sides of the membrane. And that results in a passage of water molecules from the low-salinity side to the high-salinity side until the salt concentration reaches to equilibrium on both sides of the membrane (Lomba

Table 1
Basic reservoir, fluid and fracture properties.

Initial reservoir pressure, p_i	26 MPa	Initial reservoir temperature, T_i	323 K
Matrix porosity, φ^m	0.08	Initial matrix permeability, k_o^m	3×10^{-6} μm^2 (300 nD)
Fracture zone porosity, φ^f	0.3	Fracture conductivity, $k^f w$	0.02 μm^2 m (2 D·cm)
Connate water saturation, S_{wo}^m	0.2	Viscosity of gas, η_g	0.022 mPa s
Ideal gas constant, R	8.314 J/(mol·K)	Gas density at standard condition, ρ_{gsc}	0.77 kg/m^3
Slickwater temperature T_f	288 K	Viscosity of slickwater, η_w	0.8 mPa s
Membrane efficiency, λ	0.06	Slickwater salinity, C^{inj}	1000 ppm
Volume proportion of source rock, S_k	0.1	Langmuir's volume, V_L	3.32×10^{-3} m^3/kg
Formation brine salinity, C_o^m	280 000 ppm	Langmuir's pressure, p_L	5.8 MPa
Slickwater density, ρ_w	1000 kg/m^3	Partial molar volume of water, $V_{w,m}$	18.02×10^{-6} m^3/mol
Partial molar entropy of water, $S_{w,m}$	69.91 J/(mol·K)	Salt diffusivity coefficient, D_1 and D_2	6×10^{-11} m^2/s
Rock density, ρ_r	2560 kg/m^3	Thermal diffusivity coefficient, D_e	1.6×10^{-6} m^2/s
Heat capacity of fluid, C_w	4200 J/(kg·K)	Heat capacity of rock, C_r	774 J/(kg·K)

et al., 2000; Rahman et al., 2005; Fakcharoenphol et al., 2014; Wang and Rahman, 2015). Therefore, two conditions must be satisfied if chemical osmosis occurs during the treatment of hydraulic fracturing: clay semi-permeable membrane and salinity difference on both sides of the membrane.

A shale matrix contains a certain amount of formation brine. As a result of the water drainage during the tectonic compaction process (Bredehoeft et al., 1963) and the water consumption during the hydrogen generation process (Schimmelmann et al., 2001; Mastalerz and Schimmelmann, 2002), sub-irreducible water saturation phenomena (the initial water saturation is lower than the irreducible water saturation value, that is, the phenomenon of $S_{wi} < S_{wirr}$) happen. Studies have shown that the irreducible water saturation of shale are generally more than 50% (Ge and Fan, 2013), but the initial water saturation in North America commercial shale is very low, with an average of 15%–35% (Clarkson and Bultin, 1999; Ambrose et al., 2012). While the initial water saturation in China gas shale field trials is below 50% (Fang et al., 2015); Another result of the geological process is that the formation brine of shale has extremely high salinity (Fang et al., 2014). Haluszczak et al. (2012) showed that the brine salinity of the shale reservoir is high, reaching up to 280 000 ppm. However, the salinity of slickwater fracturing-fluid is low, approximately 1000 ppm. Moreover, in the presence of a temperature gradient across the shale–fluid interface, thermal osmosis occurs when the fluid/shale system exerts a selectivity

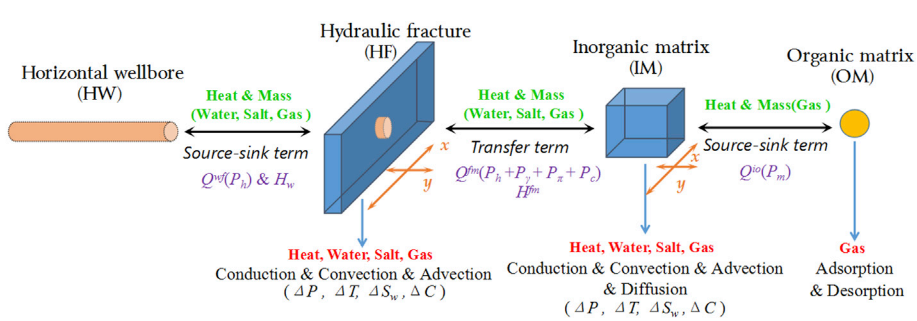

Fig. 3. Mass and heat transfer representation of the THC model.