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Modeling Fracturing-fluid Flowback Behavior in Hydraulically Fractured Shale Gas under Chemical Potential Dominated Conditions

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Abstract: Shale with high clay content has caused instability from hydration during the hydraulic fracturing process. Macro-level migration phenomenon of water molecules is induced by the chemical potential difference between low-salinity fracturing fluid and high-salinity formation brine. This study aims to establish the equation for the chemical potential difference between fracturing fluid and formation brine by theoretical deduction in order to investigate the effect of the aforementioned phenomenon on fracturing flowback. Accordingly, a mathematical model was established for the gas–water two-phase flow which driven by the chemical potential difference. Viscous force, capillarity and chemiosmosis were considered as the driving forces. A numerical simulation of fracturing fluid flowback with or without considering of the effect of chemiosmosis was performed. A simulation analysis of the water saturation and salinity profiles was also conducted. Results show that capillarity and chemiosmosis hinder fracturing fluid flowback in different degrees. As the condition worsens, they inhibit more than 80% of water to flow back out of the formation, forming a permanent water lock. This study contributes to improvement of the theory on shale gas–water two-phase flow, establishment of a flowback model that suitable for shale gas wells, and accurate evaluation of the fracturing treatment.

Keywords: shale; hydration; chemical potential; flowback; chemiosmosis

1. Introduction

Shale gas has received much attention as an important unconventional natural gas resource. The United States and Canada have commercially exploited a number of basins. Massive slickwater fracturing is one of the key technologies for realizing the fracturing stimulation in shale gas reservoirs. A large liquid measurement and displacement mode must be adopted to realize the large volume of stimulation and to meet the required sand-carrying capacity (Vera and Ehlig-Economides, 2014). Studies on fracturing stimulation in shale gas reservoirs in China and other countries show that fracturing fluid flowback rate is generally low (Chekani et al., 2010; Penny et al., 2006). In the United States, fracturing fluid flowback rate is within the range of 20%–40%. The flowback rate in a portion of Fuling shale gas wells in China is even lower, reaching only 5%–10% (Zhong, 2011). Previous studies had proven that this phenomenon is attributed to capillary imbibition or natural crack closure (Cheng, 2012; Ehlig-Economides et al., 2011; Ehlig-Economides et al., 2012; Fan et al., 2010).

Shale is composed of fine-grained sediments with strong heterogeneity. Shale mainly contains kerogen, clay, quartz, feldspar and pyrite. A shale reservoir has a relatively high clay content reaching up to 80% when compared with conventional reservoirs (Bohacs et al., 2013). In the formation process, shale with high clay content acts as a semipermeable membrane, causing osmotic water molecules permeate the membrane and migrate from the low-salinity side of the semipermeable membrane to the high-salinity side (Lomba et al, 2000; Rahman et al, 2005; Fakcharoenphol et al., 2014; Wang and Rahman, 2015). A shale matrix contains a certain amount of formation water. The original