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Impact of rock fabric on water imbibition and salt diffusion in gas shales

Ebrahim Ghanbari, Hassan Dehghanpour *

Department of Civil and Environmental Engineering, School of Mining and Petroleum Engineering, University of Alberta, Edmonton, Alberta T6G 2W2, Canada

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ABSTRACT

Understanding water uptake of gas shales is critical for designing fracturing and treatment fluids. Previous imbibition experiments on unconfined gas shales have led to several key observations. The water uptake of dry shales is higher than their oil uptake. Furthermore, water imbibition results in sample expansion and microfracture induction. This study provides additional experimental data to understand the effects of rock fabric, complex pore network, clay swelling and osmotic potential on imbibition behavior.

We systematically measure and compare the imbibition rates of deionized water and oil into wet/dry and confined/unconfined rock samples from different shale members of the Horn River Basin. We also measure the ion diffusion rate from shale into water during imbibition experiments. The results show that initial water saturation decreases the water uptake of shale samples. However, it has no effect on oil imbibition rates. The liquid imbibition and ion diffusion rates along the lamination are higher than those against the lamination. The results also suggest that confining the shale samples decreases the water imbibition rate, parallel to the lamination. However, it has a negligible effect on water uptake, perpendicular to the lamination. Furthermore, confining does not significantly affect the ion diffusion rates. The comparative study suggests that, for both confined and unconfined samples, water uptake is higher than oil uptake. However, previous experiments on crushed shale samples show that the oil uptake of crushed packs is higher than their water uptake (Xu and Dehghanpour, 2014). The data suggest that the connected pore network of the intact samples is water wet while the majority of rock including poorly connected pores is oil wet. This argument is backed by BSE images and complete spreading of oil on fresh break surfaces of the rock.

1. Introduction

Tight oil and gas reservoirs, considered "unconventional resources", have emerged as a significant source of energy supply in the United State and Canada, to supplement the decreasing supply of conventional resources and meet the increased global demands on oil and gas (Frantz and Jochen, 2005; Khlaifat et al., 2011; Zahid et al., 2007). Unconventional resources with ultralow matrix permeability are capable of producing oil and gas at economic rates when completed by hydraulically fractured horizontal wells (Ning et al., 1993). Well productivity might be improved further if the hydraulic fractures are connected to a fracture network. This fracture network may be pre-existing in a naturally fractured reservoir and/or may be generated locally by the hydraulic fracturing operation (Fisher et al., 2004; Gale et al., 2007).

Field observations point to several common and interesting phenomena observed during fracturing water flowback. During hydraulic fracturing, a great amount of water-based hydraulic fracturing fluid with low proppant concentration is injected into the target formation to create multiple fractures and increase the contact surface between the wellbore and reservoir (Holditch and Tschirhart, 2005; Palisch et al., 2010). However, only a small fraction of injected fluid, typically 10 to 20%, can be recovered during the clean-up phase (Cheng, 2012; King, 2012). Spontaneous imbibition of fracturing fluid is known as the primary mechanism for fracturing fluid loss and inefficient water recovery (Bennion and Thomas, 2005; Cheng, 2012; Lan et al., 2014a; Makhanov et al., 2014; Paktinat et al., 2006; Roychaudhuri et al., 2011; Shaoul et al., 2011). Other possible mechanisms which control the behavior of the retained water in the reservoir include gravity segregation and stress-sensitive fracture conductivities (Gdanski et al., 2009; Holditch, 1979; Parmar et al., 2012, 2013, 2014).

Spontaneous imbibition of fracturing fluid into low-permeability reservoirs and its effects on short- and long-term productivity have been extensively studied recently (Cramer, 2008; Dehghanpour et al., 2012, 2013; Makhanov et al., 2012). Fracturing fluid imbibition into the rock matrix can severely damage absolute permeability through clay swelling and clay fines dispersion (Scott et al., 2007). Furthermore, in low-permeability reservoirs, capillary pressure can be several hundred psi (Holditch, 1979) and therefore, fracturing fluid imbibition results in fluid retention (Bazin et al., 2010; Dutta et al., 2014; Economides and Martin, 2007). This process, called water blocking, causes the relative permeability of gas to be reduced and thus decreases the gas production, dramatically (Shaoul et al., 2011). On the other hand, Wang et al. (2012) investigated the impact of each damage mechanism and concluded that a higher fracturing water recovery does not always result in a higher gas production. Furthermore, previous

* Corresponding author.
E-mail address: dehghanpour@ualberta.ca (H. Dehghanpour).

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simulation studies (Agrawal and Sharma, 2013; Cheng, 2012; Settari et al., 2002) and field observations (Adefidipe et al., 2014; Ghanbari et al., 2013) show that effective imbibition and extended shut-in can improve early gas production.

Capillary pressure, which is a function of rock wettability, pore radius and interfacial tension, controls spontaneous imbibition in both conventional (Babadagli, 2001; Cai et al., 2010, 2012; Ma et al., 1997; Zhang et al., 1996) and low-permeability reservoirs (Takahashi and Kovscek, 2010; Zhou et al., 2002). Wettability of conventional reservoirs has been measured by various techniques including 1) equilibrium contact angle measurement, 2) Amott wettability index (Amott, 1959), 3) USBM wettability index (Donaldson et al., 1969), 4) spontaneous imbibition (Morrow, 1990), 5) hysteresis of the relative permeability curves (Jones and Roszelle, 1978) and 6) Nuclear Magnetic Relaxation (NMR) (Brown and Fatt, 1956), to identify the wettability of reservoir rocks. However, measuring and modeling imbibition into the organic-rich shale reservoirs is more challenging due to their mixed wettability characteristics (Curtis et al., 2010; Sondergeld et al., 2010; Wang and Reed, 2009). In addition, fine-pore nature and the lamination of the organic shales exhibit strong capillary forces due to the narrow pore radius (Karpyn et al., 2009). Furthermore, the clay minerals existing in the structure of the shales can adsorb a significant amount of water. The magnitude of water adsorption is controlled by clay chemistry and water salinity (Chenevert, 1970; Fripiat et al., 1984; Hensen and Smit, 2002). Adsorption of water induces expansive stresses that causes the clay layers to be separated (Chenevert, 1970). These expansive stresses result in swelling and inducing microfractures in unconfined shales which decreases density of shale samples (Hill and Summer, 1967) and enhances absolute permeability (Roychaudhuri et al., 2011).

Another interesting observation in the Horn River Basin and some other gas producing shales is that the concentration of dissolved salt in flowback water significantly increases with time (Blaunch et al., 2009; Pritz and Kirby, 2010; Rowan et al., 2011). Some researchers concluded that the increase in salt concentration of flowback water is due to the dissolution of shale constituents in injected water and/or diffusion of in situ brine in the injected water (Blaunch et al., 2009; Gdanski et al., 2010; Haluszczak et al., 2013). Similar to imbibition rate, the ion diffusion rate from the shale sample into water depends on porosity, permeability, contact surface and clay content (Ballard et al., 1994; Zolfaghari et al., 2014). Therefore, diffusion data can be used to complement the imbibition data.

In previous works, Roychaudhuri et al. (2011) and Dehghanpour et al. (2013) showed that water adsorption by clay minerals produces water-induced microfractures and enhances the permeability of the shale samples. Dehghanpour et al. (2012) observed that fresh water uptake of dry shale samples obtained from the Horn River Basin is much higher than their oil uptake. On the other side, Xu and Dehghanpour (2014) observed that the oil imbibition rate into crushed-shale packs is higher than water imbibition rates. Makhanov (2013) and Makhanov et al. (2014) investigated the effects of anisotropy on water imbibition rates and showed that water uptake for samples tested parallel to the lamination is higher than that tested perpendicular to the lamination. Ghanbari et al. (2013) measured the ion diffusion rates from different shale samples into water during imbibition tests and showed that the diffusion rate is correlated to water imbibition rates. Despite the recent investigations, five major questions still remain: 1) Is the excess water uptake of organic shales due to sample expansion and water induced microfractures? 2) What is the reason for higher liquid imbibition rate parallel to the lamination? 3) Does sample expansion affect the ion diffusion rate? 4) Is ion diffusion rate also an anisotropic phenomenon? and 5) How does initial water saturation affect the water and oil imbibition and ion diffusion rates? This paper extends the previous works and aims at answering these questions. The rest of this paper is divided into three sections. Section 2 describes the materials and methodology used for each set of experiments. Section 3 presents and describes the imbibition results. Section 4 discusses the results and concludes the paper.

2. Experiments

The imbibition/diffusion experiments conducted for this study can be categorized into three sets. In Set 1, we measure and compare spontaneous water and oil imbibition rates into dry and wet shale samples. We also monitor the ion diffusion rate from shale samples to water using an electrical conductivity meter, during imbibition process. The objective of this set is to investigate the effects of initial water saturation on ion diffusion and water imbibition rates. In Set 2, we measure and compare the ion diffusion and imbibition rates into confined and unconfined Otter Park and Evie shale samples. The objective of this set is to investigate the effects of sample expansion on ion diffusion and water imbibition rates. In Set 3, we measure and compare the ion diffusion and imbibition rates parallel and perpendicular to the lamination of the shale samples. The objective of this set is to understand the effects of anisotropy on liquid imbibition and ion diffusion rates.

2.1. Materials

The experimental materials include fluids used for imbibition tests and shale samples.

2.1.1. Fluids

Kerosene and deionized (DI) water are used for the imbibition/diffusion tests. Density, viscosity and surface tension of fluids are listed in Table 1.

2.2. Shale samples

2.2.1. Geological overview

Fort Simpson (FS), Muskwa (MU), Otter Park (OP) and Evie (EV) formations belong to the Devonian age of the Western Canada Sedimentary Basin. Fort Simpson is a thick and clay rich shale which seldom has TOC content above 1 wt.% (Beaudoin et al., 2011). However, TOC of the Horn River Group, which is comprised of MU, OP and EV shales, is approximately 4 wt.%. The substantial gas resource in the Horn River Group made it the third largest North American natural gas accumulation discovered before 2010 (Graham, 2009).

2.2.2. Shale sample characteristics

A total of 22 shale samples is used for this study. The core samples are selected from wells completed in Otter Park and Evie formations. The average mineral concentration of shale samples determined by x-ray diffraction (XRD) analysis is given in Table 2. The physical properties and average depth of intact shale samples used for imbibition tests are presented in Table 3.

2.2.3. Contact angle measurements

Fig. 1 shows the droplets of DI water and oil (kerosene) on the clean surfaces of the OP and EV samples. The section of shale samples is prepared by breaking sample with hammer. This allows us to have a fresh break for contact angle measurement test and avoids surface contamination. The surface of shale samples is polished using sand paper to make the surface flat. The pictures show that oil droplets completely spread on the rock surface. However, water droplets show a measurable

Table 1
Properties of different fluid used for imbibition experiments at 25 °C.

Fluids	Density (g/cm^3)	Viscosity (cp)	Surface tension (N/m)
DI water	1.00	0.9	72
Kerosene	0.80	1.32	28