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A critical review of water uptake by shales

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ABSTRACT

The shale boom in North America started more than a decade ago, however, the issue of substantial fracturing fluid loss inside shale did not draw much attention for a decade. In the past few years, many researchers conducted laboratory experiments to 1) observe various processes by which water imbibes into shale rocks, and 2) understand the mechanisms behind each process that contributes to fluid uptake in shale. Although there is consistency in most of the observations that control the liquid filling in shales, some issues remain in regards to wettability. Many mechanisms seem to be contributing to liquid filling in the laboratory experiments, but there is no consensus on the dominant mechanisms. Even though some observations from field provide consistent signatures, we do not yet have a verified answer for the geo-mechanisms behind those observations.

This paper provides a critical review of the observations (laboratory and field), the mechanisms behind those observations, and the models to mimic the imbibition behavior of shales. In this regard, following contents are critically reviewed: 1) history of imbibition in shales, 2) laboratory observations, 3) field observations, 4) mechanisms of water imbibition in shales, and 5) simulation models. We also discuss evaporation of water in shale as an additional mechanism that has not been proposed before, but may be contributing to the loss of water in shale formations.

1. Introduction

Problem of water retention in oil and gas reservoirs was first described a century ago by Mills and Wells (1919) where they discussed water-related issues in the Appalachian oil and gas fields. However, more recently this problem has been revisited in the context of fracturing fluid loss in shale reservoirs. Economical production from shale formations requires creating hydraulic fractures by pumping large volume of water (~2–6 million gallons) with proppants at high pressure to keep the fractures from closing. Once the fracturing job is completed, the injection pressure is reduced and the fracturing fluid is allowed to flow back from the well for a brief period (~10 days) before shutting-in the well for a longer period (~few weeks to months) to prepare for the hydrocarbon production. Sometimes, after fracturing operation the well is shut-in without a brief flow back period. On average, only 6–10% of the injected water is recovered in the US across all shale plays (Vandecasteele et al., 2015; Mantell, 2013), whereas the unrecovered part of the injected fluid is believed to be imbibed by surrounding shale matrix, micro-fractures and other fracture network through various mechanisms. The recovered amount of water tends to be two times more in the case of liquid shale plays (Bakken, Eagle Ford, Mississippi Lime) compared to the recovered amount in the case of dry gas shale plays (Barnett, Marcellus, Haynesville). The lowest reported amount for recovered water has been 5% for the Haynesville shale (primarily dry gas), while the highest reported amount has been 48% for the Mississippi Lime (primarily oil). One of the most prolific shale play in the US, Eagle Ford, has produced less than 20% of the injected fracturing fluid in its entire production history (Nicot and Scanlon, 2012). This abundant retention of fracturing fluid inside the shale formations is a cause of major concern because it keeps the hydrocarbons from flowing out of the reservoir by reducing the relative permeability of the hydrocarbons inside the formation.

Low recovery of fracturing fluid could be due to a number of different mechanisms, such as i) retention within fractures due to fracture volume closure during early flowback depletion (Ezulike et al., 2015), and/or ii) imbibition into the shale matrix due to capillary forces (Settari et al., 2002; Cheng, 2012) and electro-chemical forces (Xu and Dehghanpour, 2014; Zolfaghari et al., 2016; Binazadeh et al., 2016; Roshan et al., 2016a). The focus of this paper is to summarize and analyze the published laboratory and field observations. We also discuss various mechanisms that contribute to loss of fracturing fluid inside shale and a brief review of simulation models.

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2. Brief history of imbibition in shales

Bell and Cameron (1905), Lucas (1918) and Washburn (1921) investigated the fluid invasion in the capillaries of constant cross section with negligible gravity and inertia. They found that the fluid in the capillary rises as a square root of time ($l(t) \propto \sqrt{t}$), and that result is popularly referred to as the Lucas-Washburn (LW) equation. Traditionally, imbibition in a homogeneous porous media has been described by the Handy (1960) model, who developed a famous gas-water imbibition expression by equating the velocity from Darcy's law with the velocity of a piston like displacement obtained from mass-balance of two immiscible fluids. Handy (1960), obtained an equation for the volume of the mass imbibed as a function of time that scaled as $\sqrt{t}$, which incidentally, is similar to the scaling of imbibition length ($\propto \sqrt{t}$) given by LW equation. Spontaneous imbibition in conventional reservoir rocks is primarily driven by capillary force, and it is known to be mainly influenced by tortuosity and reservoir heterogeneity (Cai and Yu, 2011). Satisfactory advancements have been made to account for these properties on imbibition dynamics in conventional reservoir rocks using fractal theory (Cai et al. 2010, 2012).

Compared to our mature knowledge of imbibition in conventional reservoir rocks, research on imbibition in shales is still developing. Research on imbibition in shales gained some attention with the study of Roychaudhuri et al. (2011) who investigated the impact of spontaneous imbibition on gas production through experiments performed on shale samples. Prior to that, two modeling studies (Settari et al., 2002; Cheng, 2012) had hypothesized that the poor recovery efficiency of fracturing fluid is due to capillary imbibition in shale matrix. Based on laboratory observations from past few years, it is known that the imbibition length in shales deviates significantly from the Handy model, or in other words the time exponent deviates from 0.5 by a significant margin (Hu et al., 2012; Roychaudhuri et al., 2013; Hu and Ewing, 2014; Liu et al., 2015; Hu et al., 2015a; Yang et al., 2016). Currently, there is no unique theory to explain this deviation, but different studies attribute this deviation to different reasons, for example low pore connectivity in shales (Hu et al., 2012, 2015b), complex microstructure consisting of natural/micro-fractures and tight matrix (Yang et al., 2016; Sun et al., 2015), clays and different rock mineralogy (Ge et al., 2015; Roshan et al., 2016b; Makhanov et al., 2014), and osmotic effects (Xu and Dehghanpour, 2014; Zolfaghari et al., 2016; Binazadeh et al., 2016; Roshan et al., 2016a). Even though the research on imbibition in shale is only a few years old, previous knowledge from the field of micro- and nanofluidics (Huber, 2015; Li, 2008) suggest that the geometry of the medium, the fluid-wall interaction, the fluidity and capillarity of the liquid imbibed, all play an important role in determining the volume of imbibition. However, the imbibition dynamics in shale is more complex than in nanofluidic devices because of the i) heterogeneity in pores types and its geometries, and ii) electro-chemical forces due to clay hydration and osmosis.

3. Laboratory observations

Since Roychaudhuri et al. (2011) reported that significant fractions of the injected fracturing fluid can be absorbed by the shale, many experimental studies have been conducted to study the imbibition of fluids in shale. Evidently, most of the experiments report consistent results, while some studies have reported contradictory observations. Here, we only present typical observations that have been reported in the literature. Observations from laboratory experiments are reported in two different sections in order to separate two different mechanisms of imbibition – i) imbibition due to capillary forces, and ii) imbibition due to electro-chemical forces.

3.1. *Typical imbibition behavior in shales*

Imbibition of a liquid in a medium is generally characterized by a curve between the length of liquid intake versus square root of time. The slope of that curve represents the rate of imbibition, and the maximum imbibition length is given by the peak value of the curve. Typical behavior of liquid imbibition in a Berea sandstone consistently shows 0.5 slope on a log-log plot between liquid intake and time for various samples (Hu et al., 2012). However, imbibition experiments performed on various shale rocks from China produce a curve that depict multiple regions with slope values that can vary from 0.1 to greater than 0.5 on a log-log scale (Yang et al., 2016), whereas the slopes of the curves obtained from shale formations in the US depict a consistent value of 0.25 (Hu et al., 2012, 2015a). This anomalous behavior in shales has been attributed to two reasons, which are coupled together: i) poor pore connectivity and highly heterogeneous pore network, and ii) presence of clays.

3.2. *Imbibition due to capillary forces*

3.2.1. *Wettability and fluid properties*

Wettability

The wettability of a rock is one of the key factors that control the imbibition dynamics through capillary pressure. The wettability of shale reservoir rocks has been experimentally investigated by a number of researchers for shale rocks across the US (Odusina et al., 2011; Wang et al., 2012), Canada (Borysenko et al., 2009; Makhanov 2013; Xu and Dehghanpour, 2014; Lan et al., 2014, 2015), Australia (Roshan et al., 2016b), China (Liang et al., 2016) and Poland (Ksiezniak et al., 2015). Lan et al. (2014, 2015) studied the effect of wettability on the imbibition dynamics by comparing the behaviors of water and oil phases on rock samples from two shale plays in Western Canada, the Montney and Horn River. They observed that the oil completely spreads on the shale sample, while water droplets show a measurable contact angle that is greater than 37°, therefore, they concluded that the observed wettability cannot be fully explained by the contact angle results. They suggested that the wettability of shale rocks i) is affected by the connectivity of hydrophobic and hydrophilic pores, and ii) has strong affinity for oil in presence of degraded bitumen. Similar behavior was observed by Liang et al. (2016) for shale samples from Lower Longmaxi formation in China, although the contact angle for water varied between 12° to 37° at elevated and normal temperature, respectively. Wang et al. (2012) tested core samples from three wells in Bakken formation, and majority of the results showed that the samples were generally oil-wet or intermediate-wet. Odusina et al. (2011) studied samples from three shale plays (Eagle Ford, Barnett, and Floyd strata) that showed oil-wet or mixed-wet nature. Ksiezniak et al. (2015) studied the wettability of shale rock samples from Baltic Basin, Poland, and found the contact angle of oil to be almost two-times smaller (44°) than the contact angle for water (85°). Roshan et al. (2016a) studied the wettability of a shale sample from a nominated CO_2 storage site in New South Wales, Australia, for various pressures and temperatures. They observed that the contact angle for oil varied between 6° to 18°, whereas the contact angle for water with salt varied between 17° to 62° at various pressure and temperature conditions. Josh et al. (2012) studied different shale samples using NMR techniques and observed that illitic shales tend to be strongly water-wet while the shale with kaolinitic clays tend to be oil-wet. Xu and Dehghanpour (2014) tested the shale samples from Horn River Basin, Canada, for wettability by isolating the factors that are responsible for the excess water imbibition and observed that the connected pore