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Experimental study of the osmotic effect on shale matrix imbibition process in gas reservoirs

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ABSTRACT

Speaking of imbibition, it usually refers to the displacement of the non-wetting phase by the wetting phase in a porous medium by capillary action. Most of the focuses in the technical literature of this area have been given to the factors related to capillarity and viscous forces with or without gravity effect. However, solute (ions/salt)-rock interaction has been overlooked for long, which is also a critical imbibition mechanism as solvent (water)-rock interaction. Moreover, different from conventional sandstone and limestone, shale gas formations exhibited semi-permeable properties due to high clay content and unique pore structure, which result in the osmotic effect. This may explain the low amount of fracturing fluid flowback and the osmosis diffusion-enhanced imbibition could be a critical recovery mechanism from the low permeability rock.

Hence, it is important to investigate the imbibition behavior in the fracture network of stimulated reservoir volume which created by hydraulic fracturing. In this study, shale samples from Horn River shale gas formation were used to conduct spontaneous imbibition tests to study the effect of capillarity and osmosis diffusion. To simulate the process during hydraulic fracturing, the fluids with different salinities were used in the experiment.

The experimental results showed that the clay content in shale samples determined how capillarity and osmosis diffusion influenced the imbibition process. The linear relationship between imbibition mass and square root of time was observed only in the lower clay content shale samples. The imbibition process in these samples was dominated only by capillarity. That relationship was used to predict the imbibition mass during the water flooding work. On the other hand, in the higher clay content shale samples, due to osmotic effect, the relationship between imbibition mass and square root of time was non-linear.

The results of this study can help people understand the imbibition process of the fracturing fluid when fluid contacts with the shale rock during hydraulic fracturing. Adjusting the salinity of the fracturing fluid to change osmotic effect in the shale formation can be used to control fracturing fluid imbibition.

1. Introduction

Although the hydraulic fracturing technology can dramatically increase the production of the shale gas reservoir, one of the most serious concerns is that the fracturing fluid may damage the formation since more than 50% of the injected fluid could not be recovered during the fracture cleanup (King, 2010). The remaining fluid could be imbibed by the shale rock and then be trapped inside the shale matrix (Zhou et al., 2014). The imbibition fluid reacts with clay minerals and causes clay swelling (Ghanbari et al., 2014). In addition, the trapped fluid in the porous media impedes production in the shale formation (Charoenwongsa, 2011). Therefore, imbibition needs to be investigated in the shale gas formation during the hydraulic fracturing treatment.

Imbibition is defined as one fluid being displaced by another immiscible fluid. Normally, those fluids are liquid, but sometimes gas can also a displaced or displacing fluid. Handy (1960) developed solutions to describe the imbibition process when oil was displaced by water. The derivation process is from Eq. (1)–(3).

$$\begin{cases} u_w = \frac{k_w}{\mu_w}\left(\frac{P_c}{x} - \Delta\rho g\right) \\ u_w = \phi S_w \frac{\partial x}{\partial t} \end{cases} \tag{1}$$

$$\frac{\partial x}{\partial t} = \frac{k_w}{\phi \mu_w S_w}\left(\frac{P_c}{x} - \Delta\rho g\right) \tag{2}$$

$$Q_w = \sqrt{\left(\frac{2P_c k_w \phi A^2 S_w}{\mu_w}\right)}\sqrt{t} \tag{3}$$

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Fig. 1. One example of the shale samples. Left is the original sample size; right is the plug size for the imbibition experiment.

Table 1
Rock properties and mineralogy of the samples.

	Depth m	Permeability μD	Porosity %	Quartz % of Wt	Calcite % of Wt	Dolomite % of Wt	Clay % of Wt	Salinity mg/l (ppm)
Shale sample No. 1	2539	0.095–0.1	3.6–6.1	32	1	1	53	69,554 ~ 92,215
Shale sample No. 2	2668	0.137–0.159	2.1–3.5	35	1	5	43	60,751 ~ 67,948
Shale sample No. 3	2693	0.317–0.589	5.8–6.5	50	38	2	4	51,210 ~ 52,801
Sandstone sample	N/A	1730–2160	16.4–16.7	48	1	24	16	N/A
Limestone sample	N/A	1450–3029	14.3–15.6	1	92	6	trace	N/A

u_w is flow rate; k_w is effective water permeability; μ_w is water viscosity; P_c is capillary pressure; x is distance; $\Delta\rho$ is density difference between water and air; g is gravity acceleration; ϕ is porosity; S_w is water saturation; t is time; Q_w equals total imbibition volume; A is cross sectional area.

According to Eq. (3), the imbibition volume is proportional to the square root of time. There is a linear relationship between the imbibition amount and the square root of time. The assumption of the derivation is that the imbibition is a piston-like flow and capillary pressure provides the driving force. The linear relationship was observed in the imbibition experiment in sandstones (Handy, 1960).

Garg et al. (1996), Schembre et al. (1998), and Li and Horne (2000) all proved the validity of linear proportion. They observed the straight line in their spontaneous imbibition experiments of the sandstone, diatomite, chalk, consolidated Berea sandstone and unconsolidated glass-bead pack. Those previous studies believed that the linear relationship to the square root of imbibition time was an effective way to predict the imbibition amount during the water flooding work in the formation.

When imbibition was studied in shale reservoirs during hydraulic fracturing, various experiments were applied to investigate the imbibed volume and rate (Roychaudhuri et al., 2011; Makhanov et al., 2012, 2013; Zhou et al., 2014, 2016b; Akbarabadi et al., 2015). In addition, Roychaudhuri et al. (2011) and Makhanov et al. (2012) studied the imbibed volume as a function of square root of time to characterize the imbibition process through Handy's equation. However, both studies indicated that the linear relationship was not observed in shale samples. Thus, Roychaudhuri et al. (2011) said the counter-current imbibition interrupted the relationship and led to the non-linearity.

Roychaudhuri's explanation may be one of the reasons. But more possible reason is that osmotic pressure exists in the shale and control the imbibition process. The linear relationship exists only when capillary pressure is the sole driving force based on Handy's assumption. The second driving force, osmotic pressure, causes the non-linear relationship.

Osmotic pressure is generated when water molecules spontaneously move from low salinity fluid to high salinity fluid through a semi-permeable membrane that only permits certain molecules to pass. This kind of movement is called osmosis diffusion (Tuwiner, 1962). In clay-rich shale gas formation, clay mineral is distributed around the porous space whose size is very small so that fluid must flow through the clay. Clay has a salt-exclusionary behavior that restricts salt but only allows water to pass through the clay structure (Fritz, 1986). Thus, clay is analogous to a semi-permeable membrane (Fakcharoenphol et al., 2014). In addition, concentration gradient between inside and outside shale rocks exists when fracturing fluids that have various salinities contact rocks. Therefore, osmosis diffusion happens and affects shale matrix spontaneous imbibition process.

Osmotic and capillary pressure has been proven to control imbibition process in the previous paper (Zhou et al., 2016a). In that paper, based on the spontaneous imbibition experiments in the shale samples from three formations, it found osmotic and capillary pressures alternately controlled imbibition process. Osmosis diffusion dominated the imbibition process when the water saturation in the rock was high to cause a small capillary pressure because of the reciprocal relationship between capillary pressure and water saturation. Capillarity controlled the imbibition process when the water saturation is low so that capillary pressure was higher than osmotic pressure. When the osmosis diffusion controls the direction of the fluid flow could be changed due to the concentration difference between inside and outside rocks. Also in the paper, the osmotic pressure is proved to be the driving force for the fluid to be imbibed into the rock when the salinity inside the rock was higher than the outside. On the other hand, the fluid could flow out from the rock because of the osmotic pressure when the salinity is higher outside (Zhou et al., 2016a).

In this paper, it indicated that for the shale formation the traditional way, based on the linear proportion, was hard to predict the imbibition amount. That was because that the osmosis diffusion interrupted the imbibition to change the relationship in shale.

2. Experimental samples

The shale samples in the experiment were from Horn River Shale gas formation in Canada. Those samples were in three strata of the formation so that the rock properties and mineralogy were miscellaneous. During coring, shipping, and storing, those samples were taken appropriately to ensure that the sample in the experiment had a similar condition in the reservoir.