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Effect of hydration on fractures and permeabilities in Mancos, Eagleford, Barnette and Marcellus shale cores under compressive stress conditions

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ABSTRACT

Hydration swelling was observed to generate microfractures at ambient conditions in some of earlier studies, thus the core permeability is increased. In this paper, to investigate if hydration swelling could induce fractures in shale cores under compressive stress, four shale cores (Mancos, Barnett, Marcellus and Eagleford) with various clay mineral contents and swelling properties were used. CT scan testing was used to observe fractures, and swelling strain testing was conducted to evaluate the hydration swelling properties. The permeabilities of shale cores before and after hydration were measured. In all of the four shale cores under 3000 psi isotropic confining pressure, hydration caused fractures to close rather than propagate. As a result, the permeabilities decreased significantly, up to two orders of magnitude, compared to intrinsic permeabilities in Mancos, Barnett, and Marcellus shales, and a large damage occurred in the Eagleford shale core. Clay mineral content was the main factor influencing the shale permeability damage due to hydration. When clay contents are higher than a certain percent (e.g., 15% in this paper), significant permeability damage was observed. 8% KCl solution could help recover more permeability damage than 4% KCl solution. As a result, during hydraulic fracturing, the salinity should be increased to mitigate the permeability damage caused by hydration.

1. Introduction

Recent technological developments in horizontal drilling and hydraulic fracturing have enabled enhanced recovery of unconventional gas in the United States, causing the shale oil/gas development to surge (Vidic et al., 2013; Dehghanpour et al., 2013; Morsy and Sheng, 2014; Roshan et al., 2015). After hydraulic fracturing, the fraction of recovered flowback water ranged from 9% to 53% with an average of 10% or even lower than 10% (Vidic et al., 2013; Sun et al., 2015; Binazadeh et al., 2016). Various clay minerals exist in shale and have great affinity for water (Mao et al., 2010). Water absorption on clay minerals in shale is often accompanied by a change in the crystal dimension of clay minerals that manifests the swelling of the rock, leading to cracks and fractures. Dehghanpour et al. (2013), Ji and Geehan (2013), Morsy and Sheng (2014), and Roshan et al. (2015) reported that low-salinity water imbibition was considered as an enhanced recovery method in shale oil/gas reservoirs because the tensile fractures can result from hydration swelling. However, Behnsen and Faulkner, 2011, Duan and Yang (2014), and Faulkner and Rutter (2000) reported that with isotropic confining pressure, significant reduction was observed in the permeability of clay-bearing rocks or montmorillonite samples measured with water. The expansion behavior induced by the absorption of water into swelling clay minerals was considered to be an important reason for the relatively lower water permeability. Whether or not fractures can be induced to increase permeability after hydration in shale under compressive stress condition remains controversial.

Therefore, investigation of the effect of hydration swelling on shale fracture generation with stress loaded is critical to reveal the actual interaction between hydraulic fracturing fluid and shale rock, and to determine the salinity of fracturing fluid to enhance shale hydration or inhibit shale hydration. CT scan tests were used to monitor hydration induced fracture propagation. Free swelling strain tests were conducted to evaluate shale swelling properties. Shale permeability was measured under compressive stress conditions.

2. Shale characterization

The mineralogical composition of shale samples was determined by

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X-ray diffractometry using an X'Pert-Pro MPD diffractometer with a source of Cu-Kα radiation equipped with solid-state detector and operated at 40 KV and 40 mA (PANalytical B.V.; Netherlands).

As shown in Table 1, Quartz was dominant in Mancos, Barnett, and Marcellus shale samples and the total clay proportion was 15%, 33%, 19%, respectively. Calcite was the main composition in Eagleford shale and the total clay proportion was 6%.

Illite and mixed-layer clay were the main type of clays in Mancos, Barnett, and Marcellus shale samples. The proportions of illite were 30%, 35%, 92%, respectively. The proportions of mixed-layer clay were 61%, 53%, 4%, respectively. Kaolinite and mixed-layer clay were the main clay minerals in Eagleford shale and the proportions were 57%, 35%, respectively. According to Zhang et al. (2015, 2016), illite and mixed layer clay can absorb a large number of water molecules. As a result, much clay hydration will be expected in Mancos, Barnett, and Marcellus shale.

2.1. Experimental

2.1.1. CT tests of hydration induced fracture propagation under isotropic confining pressure

The CT tests were conducted using a NL3000 CERETOM™ X-ray CT scanner (NeuroLogica Corporation, USA). The space resolution of the CT machine is 0.35 mm*0.35 mm, and the minimum recognizable volume is 0.1225 mm^3 (with thickness 1 mm). The relative density resolution is 0.3% Hu. The maximum source voltage of the X-ray is 120 kV. During the CT test, CT core holder system, presented in Fig. 1, was used to apply isotropic confining pressure.

The shale core dimensions were 38 mm (Diameter) and 76 mm (length). The shale core was put in the CT core holder system where axial load was the same as the applied confining pressure. Water could flow into the core through the inlet surface of the core.

After initial positioning, the confining pressure (cp) of the shale core was gradually increased up to a designed value (15, 3000 psi, respectively). Then water was pumped in to the core inlet at a constant pore pressure (po) 5 psi. Real-time CT scanning for selected cross-sections was conducted at various times to observe hydration induced fracture propagation. The scanning thickness was 1.25 mm.

2.1.2. Shale free swelling strain test

Shale swelling strain tests were conducted to characterize the magnitudes of swelling stress in the four shale cores. Cylindrical samples of 38 mm in diameter and 76 mm in length were used during the shale swelling tests. Shale swelling strain was tested following the procedure reported by Axel and Ge (1997). The strain gauges (1.78 mm in width and 3.18 mm in length) were cemented to the surface of the samples to measure strain in axial and lateral directions. A waterproof silicon rubber (an excellent electrical insulator, even in brine) was used as a protective coating for the strain gauges and connections. All measurements were carried out at a room temperature, which was kept approximately constant and was monitored. The sample with the frame was then placed in a beaker and the core inlet surface was immersed in the distilled water. The strain was recorded continuously for several days.

2.1.3. Shale permeability test

The permeability tests under isotropic compressive stress were conducted using an Autolab-1000 servo-hydraulic operated system (New England Research Company, USA), with the core holder similar to the CT core holder. The fluids used were N2, water, and KCl solution.

A pressure pulse decay technique was used to measure permeability. Shale permeability was calculated based on Equation (1) (Brace et al., 1968),

$$\frac{p(l,t)-p_i}{p_u-p_i}=1-e^{\left(-\frac{Akt}{\mu\beta Vl}\right)} \tag{1}$$

where p_u is upstream pressure, MPa, $p(l,t)$ is the downstream pressure at time t, MPa, p_i is initial pore pressure, MPa, A is core cross section area, cm^2, μ, is dynamic viscosity, mPa·s, V is closed reservoir volume, cm^3, β is the fluid compressibility, atm^{-1}, and k is the permeability, Darcy, l is core length, cm. Intrinsic permeability can be achieved based on shale N_2 permeability at different pressure by Klinkenberg correction.

The shale core dimensions were 38 mm (Diameter) and 12.5 mm (length).

(1) The shale core was put in the core holder frame of Autolab-1000 servo-hydraulic operated system and the confining pressure (equal to axial load) of the shale core was gradually increased up to a designed value (20 MPa (~2900 psi)).
(2) The intrinsic permeability can be measured using N_2 at different pressures by the Klinkenberg correction. Then the upstream pressure was gradually increased up to designed values of 3.00, 5.00, 7.00, 9.00 MPa (435, 725, 1015, 1305 psi), respectively with N_2. The downstream pressure will build up until the equilibrium was achieved between the upstream and downstream pressures. After 24 h for N_2 to equilibrium in the shale core, 0.5 MPa (72.5

Table 1
Mineralogical composition of Mancos, Barnett, Marcellus and Eagleford shale samples.

	Proportion of minerals in total sample (%)									
	Quartz	Potassium feldspar	Plagioclase	Calcite	Ankerite	gypsum	Siderite	Pyrite	Fluorapatite	Total clay
Mancos	55	3	5	8	12	–	1	1	–	15
Barnett	49	4	4	–	–	1	–	2	7	33
Marcellus	56	–	4	11	4	–	–	6	–	19
Eagleford	17	–	–	76	–	1	–	–	–	6

	Proportion of clay minerals in total clay (%)			
	Illite	Kaolinite	Chlorite	Mixed layer (Illite/Montmorillonite)
Mancos	30	7	2	61
Barnett	35	7	5	53
Marcellus	92	2	2	4
Eagleford	6	57	2	35

	Proportion of layers in mixed-layer clay (%)	
	Montmorillonite	Illite
Mancos	30	70
Barnett	20	80
Marcellus	40	60
Eagleford	20	80