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Study of the propagation of hydration-induced fractures in mancos shale using computerized tomography

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1. Introduction

Drilling in shale formations accounts for approximately 75% of drilled footage and contributes to approximately 90% of wellbore stability problems encountered. These problems can include hole collapses, tight holes, stuck pipes, poor hole cleaning, hole enlargement, plastic flow, fracturing, and well control, all of which cause a loss of billions of dollars per year worldwide, as reported by Zeynali[1] and Zhang et al.[2] Recent studies[3–5] show that hydration-induced fracture propagation can enhance oil and gas recovery. Water absorption in shale is often accompanied by a change in the crystal dimensions of clay minerals, which leads to rock swelling and fracture generation. A hydration-induced fracture refers to a fracture generated due to a chemical interaction between water and shale. During hydraulic fracturing, pore pressure increases when the fracturing fluid is pumped into the reservoir. When the effective tensile stress is more than the fracture closure pressure, a hydraulically-induced fracture is generated. As reported by Dehghanpour,[3] Ji and Geehan,[4] and Morsy and Sheng,[5] water imbibition can create hydration-induced microfractures, which can enhance the sample permeability and, in turn, enhance shale oil and gas recovery.

Understanding and investigating hydration-induced fracture propagation over time is critical to evaluating either the shale structural damage and wellbore stability due to hydration, or the reason for shale oil and gas recovery improvement. Water adsorption in shale is often accompanied by a change in the crystal dimension of clay minerals, which manifests itself as a swelling of the rock, leading to severe structural damage and fracture propagation.[6] Many attempts have been made to describe hydration-induced fracture propagation. The crack distribution on a rock surface can be observed by an optical or electron microscope,[7,8] while the crack distribution and propagation process on an internal cross-section can be established by using the time-lapsed computerized tomography (CT) technique.[9–12] Shi et al.[13] and Ma and Chen[14] observed fracture propagation in shale due to hydration with the CT technique and concluded that hydration-induced fractures cause shale strength damage, but they did not discuss the fracture propagation process in detail. It is very important to know the fracture geometry variation over time, because such data can help drilling engineers adopt appropriate strategies to maintain wellbore stability, or help reservoir engineers evaluate the effects of secondary fractures on oil- and gas-flowing channels. To gather more details about the hydration-induced fracture propagation process, a CT scan device was used to record fracture propagation at ten time points. CT lateral cross-section images and digital image processing techniques were used, including the reconstruction of core vertical cut faces and 3D fractures, to investigate hydration-induced fracture propagation in details.

2. Experiment

2.1. Shale characterization

A Mancos outcrop shale core was purchased from Kocurek Industries, Inc. To achieve the least water content and the highest

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Table 1
Mineralogical composition of Mancos shale samples.

Proportion of minerals in total sample (/percent)							
Quartz	Potassium feldspar	Plagioclase	Calcite	Ankerite	Siderite	Pyrite	Total clay
55	3	5	8	12	1	1	15
Proportion of clay minerals in total clay (/percent)							
Illite	Kaolinite	Chlorite	Mixed layer (Illite/Montmorillonite)				
30	7	2	61				
Proportion of layers in mixed-layer clay (/percent)							
Montmorillonite			Illite				
30			70				

degree of shale hydration, the shale core was kept in a drying oven at 100 °C for 24 h. The mineralogical composition of the shale sample was determined by X-ray diffractometry using an X'Pert-Pro MPD diffractometer with a source of Cu-Kα radiation equipped with a solid-state detector and operating at 40 kV and 40 mA (PANalytical B.V.; Netherlands).

According to Table 1, quartz was dominant in the Mancos shale sample and the total proportion of clay was 15%. Illite and mixed-layer clay were the main clays in the shale. The proportion of illite was 30%, and the proportion of mixed-layer clay was 61%, with a little kaolinite and chlorite.

2.2. Experimental apparatus and material

The 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 a thickness of 1 mm). The relative density resolution is 0.3% Hu. The maximum source voltage of the X-ray is 120 kV. Distilled water was used as the test solution.

2.3. Experimental methods

The shale core dimensions were 38 mm (diameter) and 50 mm (length). The shale core was put in a core holder system to impose a confining pressure. Water could flow into the core through the inlet surface of the core. After initial positioning, the confining pressure of the core was gradually increased to 15 psig. Then, water was pumped into the flowing channels constantly at 5 psig. Time-lapsed CT scanning for selected cross-sections was conducted to show hydration-induced fracture propagation processes. The scanning thickness was 1.25 mm.

3. Results and discussion

3.1. Hydration stress

The effective stress of shale with hydration swelling stress[6] can be described as

$$\dot{\sigma}_{ij} = \left(K - \frac{2G}{3}\right)\dot{\varepsilon}_{kk}\delta_{ij} + 2G\dot{\varepsilon}_{ij} + \sigma_h$$

$$\sigma_h = \mathbf{m}\frac{\omega_0}{c}\left(\frac{1-2c}{1-c}\right)\dot{c} \tag{1}$$

where σ_{ij} and ε_{ij} are the components of the total stress and strain tensors, σ_h is the shale hydration stress, c is the solute mass fraction, K and G are the bulk modulus and shear modulus of porous media, respectively, ω_0 is the swelling coefficient, and $\mathbf{m} = [1\ 0\ 0;\ \ 0\ 1\ 0;\ \ 0\ 0\ 1]$.

Shale gas reservoirs are only partially water-saturated. Capillary suction and imbibition due to other effects associated with introducing water to shale samples (e.g., hydration, osmosis) sequester injected fracturing fluids. As reported by numerous researchers,[3,15–17] during the water imbibition process, water content first increases quickly and then gradually stabilizes. As can be inferred, water content variation $\dot{c}$ should be the highest in the beginning and should gradually decrease to be zero.

According to Eq. (1), hydration swelling stress can act as tensile volume stress and cause shale fractures. Driven by pore solute concentration (or shale water content) differences, water diffusion occurs in the flowing channels of shale and the resulting hydration swelling stress can cause fractures to propagate. As time passes, $\dot{c}$, the water content variation along fluid-flowing channels in shale, decreases, and σ_h, hydration stress, reduces, causing fractures to begin closing when compressive stress is applied. In addition, if there is not enough hydration stress to crack the shale, clay hydration swelling may reduce the width and length of natural fractures. According to Heidug and Wong,[6] there should be two patterns of fracture geometry variation. (1) Fractures propagate over time, the width and length of the fractures then decrease with less hydration stress, and then they become stable with the application of residual hydration stress and confining pressure. (2) Fractures close due to the hydration swelling of the shale matrix without enough hydration stress to crack the shale.

3.2. Analysis of hydration-induced fracture propagation in the direction perpendicular to shale core axial

Forty slices of core images perpendicular to the shale core axial were obtained by CT scanning. The hydration-induced fracture propagation was analyzed using four CT images taken at the locations 0, 17.5, 32.5, and 50 mm from the core inlet, as shown in Fig. 1. It is well known that human vision is less sensitive to the difference between grayscale pixels than between colorful pixels. In order to improve the contrast of the images, an adaptive pseudo-color enhancement method[18] based upon grayscale-color transformation and Otsu thresholding segmentation[19] was adopted to create color images. The fractures aperture variation with time was presented in Table 2.

Fig. 1 shows the two-dimensional cross-sectional images from the CT scanning, and those after adaptive pseudo-color enhancement. As shown in the images at zero hours (0 h), beddings develop well in the Mancos shale and micro fractures exist on each layer at different positions. These fractures may not connect to each other.

In Fig. 1, 1a means the fracture at the cross-section 1 and at the position a as an example. According to Table 2 and Fig. 1, from 1 h to 70 h, four propagation processes of hydration-induced fracture were observed. (1) As shown by fracture cross-sections-1a, -2b, and -3b, the width and length of the fracture decreased at 1 h (1 h) due to hydration swelling of clay in the shale without enough hydration stress to crack the shale. With more water diffusion in beddings or micro fractures, resulting hydration stress causes fractures to propagate. Then, water content variation along fluid-flowing channels in shale decreases, and fractures began closing as 15 psig confining pressure is applied. When the water content of the shale changed very little, hydration-induced fracture geometry became stable with the application of constant