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Hydraulic fracture propagation direction during volume fracturing in unconventional reservoirs

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ABSTRACT

Creating an artificial fracture network by hydraulic fracturing plays the most important role in unconventional oil and gas development. The propagation direction of a fracture is the base to understand the mechanism of forming a fracture network. For size limitation, the fracture propagation direction has not been well studied in labs. In this paper, a comprehensive numerical model is developed to study the fracture propagation direction during volume fracturing of unconventional reservoirs. The model is based on elastic and fracturing mechanics of a rock, as well as the maximum circumferential stress criterion and boundary element method. Simulated results prove that, the propagation direction of a hydraulic fracture is affected by formation in-situ stresses, hydraulic pressure in the fracture and the initial azimuth of the fracture. An *H* factor is proposed to evaluate the combined effect of those factors, and proved mathematically and numerically that it is a major factor controlling a fracture propagation direction. Fractures will follow the same propagation path if the *H* factor keeps constant for different stresses and pressure combination. A fracture will follow the direction of the in-situ maximum principal stress as the applied internal hydraulic pressure in the fracture is less than the maximum stress, otherwise, the fracture will try to follow its initial azimuth and yield a propagation direction path between its initial azimuth and the direction of the in-situ maximum principal stress. The work is helpful in understanding the forming process of a complex fracture network during hydraulic fracturing in unconventional reservoirs. The *H* factor is useful in reducing both lab test and numerical simulation times, making lab tests of fracture extension at high stresses and pressure viable.

1. Introduction

With the maturing of oil and gas fields, conventional reserves are becoming difficult to produce. As an alternative, unconventional resource has been actively developed in recent years. Due to the ultra-low permeability in unconventional reservoirs, volume fracturing technology becomes the fundamental technology to unlock oil and gas from these tight formations by creating complex fracture networks within them. The main function of volume fracturing is to populate secondary fractures based on the major fracture connecting the natural micro-fractures in the formation and form a fracture network (East et al., 2011; Mayerhofer et al., 2010; Shelley et al., 2011; Warpinski et al., 2009). Therefore, understanding the controlling factors of fracture propagation path becomes particularly important to control the fracture direction and create a fracture network during hydraulic fracture operation. Generally, fracture propagation is affected by reservoir geological conditions such as the length, width and density of natural fractures, in-situ stresses, rock properties and so on (Cheng, 2012a; Jin et al., 2013). Operational parameters such as the volume of fracturing fluid and proppant will also impact the propagation.

Currently, the study of fracture cracking and propagation mechanism, as well as other fracturing operational parameters, is mainly studied by two methods: first, physical experiments on core and rock specimens (Brenne et al., 2013; Bunger et al., 2011); second, the application of numerical simulation (Cheng, 2012b; Enayatpour et al., 2013; Gao et al., 2013; Li and Allison, 2011; Smith and Cooper, 1989; Sumi and Yang, 1996). However, both of them have limitations in the study of fracture propagation direction.

For the first method, reproducibility of experimental results is always a problem due to the heterogeneity and anisotropy of reservoir rock. The scope of stress and strain fields during fracturing is usually much larger than a sample size. Thus, the observed fracture propagation in labs might be different from what happened in the real oil and gas fields. Also, it is difficult to record the gradual fracture breakdown and the variation of stresses during

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the fracturing process. For the second numerical simulation, commonly used methods are finite element method (FEM), extend finite element method (XFEM), and boundary element method (BEM). FEM or XFEM requires huge computational cost, and is difficult to investigate the fracture propagation due to its limitations on grid orientation, numerical dispersion, especially the fracture propagation direction.

BEM only disperses and calculates bounders of a domain, is not necessary to define its interior points, and is suitable in handling non-singularity problem around fracture tips. Those make the method very suitable in modeling complex fracture propagation. In addition, BEM could use less elements in the same accuracy, and is computational efficient. BEM is limited to homogeneous media.

In the paper, assuming homogeneous rock, based on rock and tensile-shear failure mechanics, a numerical model using the maximum circumferential stress (MCS) theory and boundary element method (BEM) has been developed to investigate the impact of both single factor and combined effects of multiple factors on fracture cracking and extending direction. The results of this study provide references for both physical experiments and field application of volume fracturing.

2. Modeling of I–II composite fracturing

2.1. Model analyses

Traditionally, for conventional reservoirs, a fracture's cracking and propagating during hydraulic fracturing is based on rock tensile failure mechanism. A fracture cracks and propagates as the pressure, P_f, in the fracture is equal to or greater than the sum of the in-situ minimum principal stress, P_h, and the tensile strength of the rock, S_t, as follows

$$P_f \geq P_h + S_t. \tag{1}$$

From rock failure mechanics, the failure of a rock can be divided into three types: opening, sliding and tearing, known as Type *I*, *II* and *III* fractures, respectively. In volume fracturing, shear failure and tensile failure are the main failure modes under complex stress conditions (Daneshy, 2003). I order to know the cracking and propagation of a fracture, the stress near the fracture tip becomes the most critical factor. Sih and Madenci (1983) presented the theory of strain energy, which is effective for composite fracture but not valid in compression conditions (Thecatis and Andrianopoulos, 1984). In this study, we applied the MCS criterion (Erdogan and Sih, 1963) to study the composite fracturing based on the superposition of Type *I* and Type *II* failures. The schematic diagram of the fracture (angles, length, and place), stresses, and coordinate systems used in the paper are shown in Fig. 1.

In Fig. 1, P_H is the in-situ maximum horizontal principal stress (MaxHPS) (MPa); P_h is the in-situ minimum horizontal principal stress (MinHPS) (MPa); a is the half length of a fracture (m); β is the initial angle of the fracture (°), which is the angle between the fracture and the maximum stress direction; θ is the deviation angle (°) of the fracture propagation direction from its initial azimuth (m direction in Fig. 1); n is the direction perpendicular to the direction m; σ_r, σ_θ, and $\tau_{r\theta}$, in MPa, are the radial, circumferential, and sheer stresses of an arbitrary point around the tip of the fracture, and the stresses could be expressed as (Sih and Madenci, 1983):

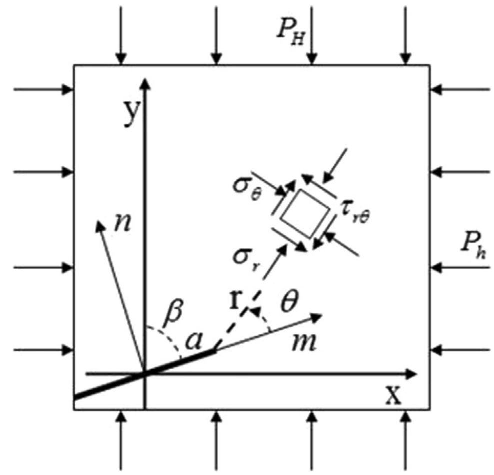

Fig. 1. Stresses around a fracture tip.

$$\begin{aligned}
\sigma_r &= \frac{1}{2(2\pi r)^{1/2}}\left[K_I(3-\cos\theta)\cos\frac{\theta}{2} + K_{II}(3\cos\theta-1)\sin\frac{\theta}{2}\right]\\
\sigma_\theta &= \frac{1}{2(2\pi r)^{1/2}}\cos\frac{\theta}{2}\left[K_I(1+\cos\theta) - 3K_{II}\sin\theta\right]\\
\tau_{r\theta} &= \frac{1}{2(2\pi r)^{1/2}}\cos\frac{\theta}{2}\left[K_I\sin\theta + K_{II}(3\cos\theta-1)\right],
\end{aligned} \tag{2}$$

where K_I and K_{II} are the stress intensity factors of tensile and shear failure respectively.

According to the MCS criterion, the cracking and propagating direction of a fracture are (Erdogan and Sih, 1963):

(1) Cracking and propagating of a fracture occur at the place with the maximum circumferential stress;
(2) The fracture will start cracking and propagating along the direction of the maximum circumferential stress once it reaches the critical value.

From the first statement, one can get the fracture propagation direction by setting $\frac{\partial\sigma_\theta}{\partial\theta} = 0$ and $\frac{\partial^2\sigma_\theta}{\partial\theta^2} < 0$. Rearranging Eq. (2), one can get:

$$K_I\sin\theta + K_{II}(3\cos\theta - 1) = 0. \tag{3}$$

The cracking and propagating angle (deviation angle) θ_0 can be determined when σ_θ gets its maximum value (maximum circumferential stress).

From the second statement, fracture begins to crack and propagate when the circumferential stress in θ_0 direction reaches a critical value, $\sigma_{\theta 0}$. Fracture toughness factor, K_{IC}, is defined to represent the critical condition as

$$K_{IC} = \sigma_{\theta 0}\sqrt{2\pi r}. \tag{4}$$

Substituting Eq. (4) into Eq. (2), one gets Eq. (5), which is the fracture criterion of I–II composite fracture based on the MCS criterion

$$\cos\frac{\theta_0}{2}\left[K_I\cos^2\frac{\theta_0}{2} - \frac{3}{2}K_{II}\sin\theta_0\right] = K_{IC}. \tag{5}$$

The values of K_I and K_{II} at the fracture tip could be calculated from Eq. (2) by using θ=0, $r\to 0$,