Theoretical and experimental study on fracture network initiation and propagation in shale that considers the capillary effect

Di Wang ^{a, b}, Mian Chen ^{a, b, *}, Yan Jin ^{a, b}, Zhixi Chen ^c

^a State Key Laboratory of Petroleum Resources and Prospecting, Beijing 102249, China

^b College of Petroleum Engineering, China University of Petroleum, Beijing 102249, China

^c The University of New South Wales, Sydney, Australia

Corresponding Author

Name: Mian Chen*

Tel: +8615210879370

E-mail: chenmiancup@163.com

Address: State Key Laboratory of Petroleum Resource and Prospecting, China University of Petroleum-Beijing,
#18, Fuxue Rd. Changping, Beijing 102249, PR China

ABSTRACT

Shale reservoirs contain multi-scale natural fractures, which result in the growth of a complex fracture network during hydraulic fracturing. However, existing studies regard natural fractures as discontinuities without considering width heterogeneity and fracturing fluid wettability. In reality, width and wettability significantly influence fracture morphology because of the capillary effect. In this study, a new model was established to simulate fracture network propagation by considering the capillary effect. The approaching angle between hydraulic and natural fractures was 90 degrees. In addition, the fracture initiation condition was considered based on the fracture mechanics. Results showed that natural fracture width and fracturing fluid wettability significantly influenced fracture network propagation. A small natural fracture width and strong fracturing fluid wettability led to the easy initiation of natural fracture and a complex fracture network propagation. Finally, the simulation results were compared with the results of hydraulic fracturing experiments in shale specimens carried out in laboratory and by other researchers. The results of the experiments are in good agreement with the results of the numerical simulations. Both the numerical and experimental results indicate that treatment parameters and geological characteristics, particularly fracture dimensions and horizontal in-situ stress difference, significantly influence fracturing results.

Keywords: Shale fracture network; Capillary effect; Width heterogeneity; Fracturing fluid wettability

1. Introduction

Natural fractures abound in shale reservoirs and significantly influence hydraulic fracturing. In the presence of natural fractures, hydraulic fracturing will develop into a complex fracture network that is substantially distinct from that in reservoirs without natural fractures (Warpinski and Teufel, 1987), as evidenced by microseismic monitoring (Maxwell et al., 2002; Fisher et al., 2002; Daniels et al., 2007). Issues on hydraulic fracture propagation in a formation with pre-existing natural fractures have been widely investigated both experimentally and numerically. Renshaw and Pollard (1995) derived a criterion to predict whether a fracture would propagate across a frictional interface that was oriented perpendicular to the approaching fracture. Experiments were conducted to validate this criterion. Zhou (2008) studied hydraulic fracture geometry in naturally fractured reservoirs through a series of fracturing experiments and determined that in-situ stress and natural fractures mainly controlled hydraulic fracture propagation. Gu and Weng (2012) developed a criterion to determine the behavior of a hydraulic fracture that encountered a pre-existing fracture at non-orthogonal angles. This criterion quantitatively accounts for the effect of intersection angle on crossing. Olson (2012) embedded planar glass discontinuities into a cast hydrostone block as proxies for cemented natural fractures. The results showed that oblique embedded fractures were more likely to divert a fluid-driven hydraulic fracture than those occurring orthogonal to the induced fracture path. These findings are consistent with the theoretical predictions. Fan and Zhang (2014) observed the evolution of hydraulic fracture networks in naturally fractured formations with specimens that contained two groups of orthogonal cemented fractures in a laboratory. The result suggests that hydraulic fracturing can generate a complex fracture network in naturally fractured formations; moreover, natural fracture density and injection rate affect

the propagation behavior of hydraulic fractures. Xu (2010) presented a numerical model to predict the growth of hydraulic fracture networks during hydraulic fracturing treatment by considering two perpendicular sets of vertical planar fractures with mechanical interaction. Meyer and Bazan (2011) constructed an induced hydraulic discrete fracture network (DFN) mathematical model and laid the foundation for predicting the behavior of discrete hydraulic fractures in shale. Weng (2011) developed a new hydraulic fracture model to simulate complex fracture network propagation in a naturally fractured formation. This model considers the interaction between hydraulic and natural fractures. Moreover, the stress shadow effect among adjacent fractures is also taken into account.

All of the aforementioned studies regard natural fractures as discontinuities without considering fracture dimensions, particularly natural fracture width. In reality, however, natural fractures are unequal. They exhibit multi-scale characteristics ranging from micro-scale to macro-scale, even to engineering-scale due to sedimentary and postdepositional processes (Wang, 2008; Wang and Reed, 2009). Small natural fractures are important properties of shale; they are critical to shale gas production when they are opened and connected with hydraulic fracture treatment (Wang and Reed, 2009; King, 2010). In the Barnett Shale, the population of narrow fractures follows a power-law size distribution where the largest fractures are open (Gale et al., 2007). These smaller fractures act as planes of weakness and reactivate during hydraulic fracture treatments (Gale et al., 2007; Gale and Holder, 2008; Jacobi et al., 2008). Moreover, nano-scale natural fractures (Fig. 1) were observed with a high resolution, versatile environmental scanning electron microscope (SEM) platform in our laboratory. These natural fractures manifest a variety of configurations. Each configuration exhibits its own connectivity and potential interaction with hydraulic fractures. The complex and pervasive multi-scale heterogeneity of natural fractures limits understanding of fracture network propagation.

Fig. 1. Nano-scale and multi-scale characteristics of natural fractures in shale specimens.

In addition, the wettability between fracturing fluid and shale was disregarded in previous studies on hydraulic fracturing. The capillary effect is a general concern during production given that it will reduce gas productivity because of water block (Holditch, 1979; Warpinski, 1991). Moreover, capillary force plays an important role in the study of wellbore stability, which is a main reason of shale instability (Yunhu et al., 2012; Liang et al., 2014). Nevertheless, the surface and capillarity forces of fluids at nano-scale in shale may produce the complicated behavior of fracture network propagation during the fracturing process. (Wang and Reed, 2009).

The width of natural fractures ranges from nano-scale to macro-scale, and even to engineering-scale. It significantly influences fracture network morphology during hydraulic fracturing. In this study, a new model was constructed to simulate fracture network propagation in shale by considering the width of natural fractures and fracturing fluid wettability. The fracture initiation condition was considered based

on the fracture mechanics. Finally, hydraulic fracturing experiments were conducted in our laboratory using shale cubic specimens from Sichuan Province. The results of experiments conducted in our laboratory and by other researchers were compared with the results of the developed numerical model. The simulation results exhibit good agreement with the experiments results.

2. Model formulation and results

Natural fractures are widely developed in shale reservoirs and their width ranges from nano-scale to marco-scale, and even to engineering-scale. When the width of a natural fracture is very small, the capillary force will be significantly enhanced. Therefore, when the wetting fracturing fluid encounters a natural fracture, fluid will be absorbed into the natural fracture because of the considerable capillary force. Subsequently, the natural fracture phase consists of two components, namely, the influent fluid, such as fracturing fluid, and the original fluid, such as natural gas. Therefore, pressure in a natural fracture is divided into two parts: the pressure of fracturing fluid and that of natural gas. The pressure of the fracturing fluid in a natural fracture is approximately equal to that at the intersection because of the connection between the fracturing fluid in natural and hydraulic fractures. In addition, the pressure of natural gas differs from that of fracturing fluid in a natural fracture with a difference in capillary force. As the fracturing fluid is of wetting capacity, the pressure of natural gas increases. As the hydraulic fracture continues propagating, the pressure at the intersection changes, which contributes to the variation in natural gas pressure. Consequently, pressure will be redistributed in a natural fracture. When the stress intensity factor at natural fracture tip exceeds fracture toughness, the natural fracture will initiate and propagate. In the hydraulic fracture propagation process, hydraulic fracture will come across a mass of natural fractures. When the fracturing fluid flows into natural fractures and causes natural fracture propagation, a fracture network will be generated. In this study, a numerical model that presented fracture network propagation by considering the influence of the capillary effect was established. Moreover, natural fractures with a small width were mainly studied. The model considered fracture initiation condition based on the fracture mechanics. The simulation results showed that a small natural fracture width and strong fracturing fluid wettability would lead to easy initiation of natural fractures and a complex fracture network. Fig. 2 shows the magnified schematic of the model, and the relevant assumptions are provided as follows.

Fig. 2. Magnified schematic of a hydraulic fracture approaching a natural fracture.

- (1) A hydraulic fracture is satisfied under a plane strain condition.
- (2) A natural fracture is a parallel plane with a small constant width.
- (3) A natural fracture is symmetrical to a hydraulic fracture, and the approaching angle between the hydraulic and natural fractures is 90 degrees.
- (4) Both the volume of the fracturing fluid flowing into natural fractures and the pressure drop in natural fractures are neglected.

- (5) Natural fractures are filled with natural gas before hydraulic fracture crosses and the gas is regarded as incompressible after fracturing fluid flows in.
- (6) Fracturing fluid leakage and natural gas percolation to the matrix are ignored.
- (7) The stress shadow effect among fractures is not considered.

2.1. Capillary effect

The capillary effect only occurs when two phases of fluid exist (Grigg et al., 1992). The essence of the capillary force is the difference between non-wetting and wetting phases. Fracturing fluid, natural gas, and petroleum are present in the reservoirs during hydraulic fracturing. When a hydraulic fracture encounters a natural fracture with a small width, the fracturing fluid is easily absorbed into the natural fracture because of capillary force. This study is mainly concerned with natural fractures with a small width and in considering the effect of width on capillary force. The capillary force diminishes rapidly as width increases, which will be specified in detail in the latter section. With regard to the constant width with a dimension at the nano-scale or micro-scale, the fracturing fluid flow into a natural fracture is negligibly small.

When a hydraulic fracture is approaching a natural fracture, it passes through at the midpoint of the natural fracture directly based on the crossing criterion (Blanton, 1982; Blanton 1986; Renshaw et al., 1995). After the hydraulic fracture crosses, the natural fracture will be divided into two branches: the upper and lower branches. Simultaneously, the fluid in the natural fracture transforms into two phases: fracturing fluid and natural gas. The gas in the natural fracture is assumed to be incompressible and leakage is regarded as zero. Consequently, gas occupation in a natural fracture does not change when fracturing fluid flows in. Under this condition, a natural fracture is completely filled with gas before its propagation. However, the capillary force will immediately occur after a hydraulic fracture passes through a natural fracture because the gas liquid interface emerges at the intersection point as soon as crossing happens. As a consequence, the pressure of natural gas equals that of fracturing fluid at the crossing point plus capillary force. As the hydraulic fracture continues to propagate, the pressure at the crossing point varies which results pressure changes in a natural fracture. Once the stress intensity factor at the natural fracture tip exceeds fracture toughness, the natural fracture will initiate and propagate. Thus, the fracturing fluid will flow into the natural fracture, as shown in Fig. 3.

Fig. 3. Schematic of the pressure distribution in a natural fracture after the crossing of a hydraulic fracture.

After the hydraulic fracture crosses the natural fracture, the pressure at crossing point A equals the pressure in hydraulic fracture, P_A .

$$P_A = P_0 + \sigma_h \quad (1)$$

where P_0 is the net pressure at the crossing point.

Disregarding pressure drop in the natural fracture, the fracturing fluid pressure in the natural fracture is also equal to the crossing point pressure. The natural fracture is vertical to the maximum in-situ stress; hence, the net pressure of the fracturing fluid in the natural fracture is

$$P_F = P_A - \sigma_H \quad (2)$$

The capillary force will appear because of the existence of the gas liquid interface. This force is determined by natural fracture width and fracturing fluid wettability.

$$P_c = \frac{2\sigma \cos \theta}{w_{NF}} \quad (3)$$

where σ is the gas liquid interfacial tension, θ is the wetting angle and w_{NF} is the natural fracture width.

Thus, the net pressure of natural gas is

$$P_G = P_F + P_c \quad (4)$$

When fracturing fluid exhibits strong wettability and the width of the natural fracture is small, the capillary force will be significant, as shown in Eqs.4. When the pressure drop is disregarded, the pressure distribution in the natural fracture will be fracturing fluid pressure and natural gas pressure.

2.2. Calculation of the stress intensity factor

Propagation happens to both hydraulic and natural fractures, when the stress intensity factor at the tip exceeds fracture toughness. The stress intensity factor is obtained based on the pressure distribution in the fracture (Nestor, 2004; Cheng, 2015).

$$K_I = \frac{1}{\sqrt{\pi L_{frac}}} \int_{-L_{frac}}^{L_{frac}} P(x) \sqrt{\frac{L_{frac} + x}{L_{frac} - x}} dx \quad (5)$$

where $P(x)$ is the net pressure distribution.

For a natural fracture, the hydraulic fracture is symmetrical and vertical to the direction of the maximum in-situ stress. Thus, the stress intensity factor of a natural fracture tip is based on Eqs.5.

$$\begin{aligned} K_I &= \frac{1}{\sqrt{\pi L_{NF}}} \int_{-L_{NF}}^{L_{NF}} P_{NF}(x) \sqrt{\frac{L_{NF} + x}{L_{NF} - x}} dx \\ &= \frac{1}{\sqrt{\pi L_{NF}}} \int_{-L_{NF}}^{L_{NF}} P_G \sqrt{\frac{L_{NF} + x}{L_{NF} - x}} dx + \frac{1}{\sqrt{\pi L_{NF}}} \int_{-a}^a (P_F - P_G) \sqrt{\frac{L_{NF} + x}{L_{NF} - x}} dx \\ &= P_G \sqrt{\pi L_{NF}} + \frac{(P_F - P_G)}{\sqrt{\pi L_{NF}}} \int_{-a}^a \sqrt{\frac{L_{NF} + x}{L_{NF} - x}} dx \end{aligned} \quad (6)$$

The numerical method is adopted because the second part of Eqs.6 cannot be integrated directly.

$$\int_{-a}^a \sqrt{\frac{L_{NF} + x}{L_{NF} - x}} dx = \sum_{i=1}^{n_{NF}} \sqrt{\frac{L_{NF} + x}{L_{NF} - x}} \Delta x \quad (7)$$

The natural fracture is discretized into n_{NF} elements.

For the hydraulic fracture stress intensity factor, coordinate transformation is introduced.

$$K_I = \int_0^L \frac{P(x)}{\sqrt{\pi L/2}} \sqrt{\frac{x}{L-x}} dx \quad (8)$$

Thus, the fracture factor intensity at [the](#) hydraulic fracture tip is obtained.

$$K_I = \int_0^L \frac{P_{HF}(x)}{\sqrt{\pi L/2}} \sqrt{\frac{x}{L-x}} dx \quad (9)$$

Eqs.9 cannot be integrated directly; [hence, the](#) numerical method is adopted.

$$K_I = \sum_{i=1}^{n_{HF}} \frac{P_{HF}^i(x)}{\sqrt{\pi L/2}} \sqrt{\frac{x}{L-x}} \Delta x \quad (10)$$

The hydraulic fracture is discretized into n_{HF} elements along [the propagation](#) direction. $P_{HF}^i(x)$ is the average pressure of the i th element obtained by the two endpoints of each element.

When condition $K_I \geq K_{IC}$ is [satisfied](#), hydraulic or natural fracture will initiate.

If $K_I < K_{IC}$, [then](#) fracture will not initiate. [However](#), the pressure in fractures will increase [because](#) fracturing fluid [is](#) continuously pumped in. [Consequently](#), K_I will increase and result in fracture initiation.

2.3. Fracture network propagation

Hydraulic fracture propagation is based on the PKN model (Perkins and Kern, 1961; Valko and Economides, 1995) and fracturing fluid is [regarded](#) as a Newton fluid. Fracturing fluid flowing into [the](#) natural fracture is negligible as mentioned [earlier](#), and leakage during fracture propagation [is also](#) not considered. The pressure drop in the hydraulic fracture during fracture network propagation is [the](#) same as [that during](#) single hydraulic fracture propagation.

$$P_{x2}^4 - P_{x1}^4 = -\frac{256\mu QG^3}{\pi H^4(1-\nu)^3} (x_2 - x_1) \quad (11)$$

Therefore, when the [length of the](#) hydraulic fracture is L , the net pressure at the bottom hole is

$$P_w^4 = \frac{256\mu QG^3}{\pi H^4(1-\nu)^3} L \quad (12)$$

The hydraulic fracture is divided into n_{HF} elements and the hydraulic fracture stress intensity factor is given by Eqs.10.

Pressure distribution in the hydraulic fracture is given by Eqs.11.

$$P_{HF}^4 = P_w^4 - \frac{256\mu QG^3}{\pi H^4(1-\nu)^3} x_{HF} \quad (13)$$

where P_{HF} is the net pressure at position x_{HF} .

Before the hydraulic fracture encounters a natural fracture, the stress intensity factor at the hydraulic

fracture tip can be obtained using Eqs.10. If the stress intensity factor is smaller than the fracture strength, then a small increment ΔP will be added to the pressure in the fracture from the bottom to the tip.

$$P_{HF}^4 = \Delta P^4 + P_w^4 - \frac{256\mu Q G^3}{\pi H^4 (1-\nu)^3} x_{HF} \quad (14)$$

Then, the pressure distribution in the hydraulic fracture will be rearranged. In addition, the stress intensity factor of the hydraulic fracture will be renewed. This situation mainly occurs during the early stage of hydraulic fracture propagation (Fig. 4). The length of the hydraulic fracture is short during this moment; hence, high pressure is required to initiate the hydraulic fracture, and the net pressure at the fracture tip is no longer zero (orange line). In particular, the pressure in the hydraulic fracture is nearly uniform during the first initiation time (red line). After the hydraulic fracture propagates for a certain distance, its initiation becomes easier and pressure increment is no longer required (blue line).

Fig. 4. Schematic of the pressure distribution during the early and late stages.

Suppose an extension length of each step ΔL . The hydraulic fracture will propagate ΔL when it achieves the initiation condition.

When the hydraulic fracture propagates in the next step, the pressure distribution can be obtained following Eqs.13 or 14. The width and the volume of the hydraulic fracture can be solved by discretizing the hydraulic fracture following Eqs.15 and 16, respectively. Therefore, the volume increment of the hydraulic fracture during a propagation step is equal to the volume difference between two continuous propagation steps.

$$w = \frac{(1-\nu)HP_{HF}}{G} \quad (15)$$

$$V = \frac{\pi}{4} wHL \quad (16)$$

Accordingly, dividing the volume increment by the pump rate yields the propagation time at each step. That is,

$$\Delta t = \Delta V / Q \quad (17)$$

When the hydraulic fracture crosses one or more natural fractures, the fracturing fluid pressure in the natural fractures can be obtained. Eqs.4 indicates the pressure of gas in natural fractures. Then, the stress intensity factors of natural fractures can be obtained using Eqs.7.

If any stress intensity factor exceeds the fracture strength, then the related fracture will initiate and propagate. However, fractures with a stress intensity factor that is smaller than the fracture strength will

stop propagating at this step. If all the fractures stop propagating simultaneously, then the pressure at the bottom hole will increase ΔP until a fracture initiates.

The distance of hydraulic and natural fracture propagation is based on Gu (1987), as follows:

$$\Delta\delta = \frac{K_I^{(i)} - K_{IC}}{K_{Imax} - K_{IC}} \Delta L \quad (18)$$

Fracturing fluid is disregarded in natural fractures; thus, the time of each propagation step can be obtained using Eqs.15 to 17.

The computation program flowchart for fracture network propagation is illustrated in Fig. 5.

Fig. 5. Computation program flowchart of fracture network propagation.

2.4. Simulation results

The input parameters used are $H=30\text{m}$, $G=15\text{GPa}$, $\nu=0.25$, $K_{IC}=1\text{MPa}\cdot\sqrt{\text{m}}$, $\sigma_H=42\text{MPa}$, $\sigma_h=40\text{MPa}$, $Q=2.5\text{m}^3/\text{min}$, $u=2\text{mPa}\cdot\text{s}$, $\Delta L=0.5\text{m}$.

Fig. 6 shows the relationship between hydraulic fracture propagation distance and net pressure at the bottom hole and the fracture tip. The pressure at the bottom hole initially decreases in a straight line, and then increases slowly with continuous propagation of hydraulic fracture. The net pressure is between 07MPa and 1.3MPa when hydraulic fracture stably propagates. The pressure at the fracture tip coincides with that at the bottom hole before fracture length exceeds approximately 1.5m, the red point, and then decreases to zero. During the early stage, a high pressure is required because of the short length of the hydraulic fracture.

Fig. 6. Pressure of the hydraulic fracture at the bottom hole and fracture tip.

When the hydraulic fracture propagates at a distance of 40m, the net pressure and width distribution in the hydraulic fracture is illustrated in Fig. 7. The pressure mainly drops near the front of the hydraulic fracture and reaches zero at the tip. The trends of the net pressure and width are the same based on Eqs.15. During that moment, the width at the bottom hole is nearly 1.9mm.

Fig. 7. Pressure and width distribution in a 40 m hydraulic fracture.

The net pressure required for a hydraulic fracture to initiate and propagate is approximately 1.8MPa and 1.2MPa, respectively (Fig. 5). When the hydraulic fracture encounters and crosses a natural fracture, the net pressure with respect to the natural fracture will have a negative value when the horizontal in-situ stress difference is 2MPa. This condition is obtained by adding the net pressure in the hydraulic fracture to the minimum in-situ stress and then subtracting the maximum in-situ stress ($1.2\text{MPa} \sim 1.8\text{MPa} + 40\text{MPa} - 42\text{MPa}$). During this moment, the natural fracture will close and not initiate. In reality, however, initiation frequently occurs in natural fractures when a hydraulic fracture crosses them, particularly under a small horizontal in-situ stress difference. The power to initiate natural fractures is just the capillary force. Under the influence of this force, the net pressure in the natural fracture may be positive, particularly when the capillary force is large ($1.2\text{MPa} \sim 1.8\text{MPa} + 40\text{MPa} - 42\text{MPa} + \text{Capillary Force}$).

Before showing the results of fracture network propagation, we focus on the assumption that the width of the natural fracture remains unchanged after its initiation and the fluid flowing into natural fractures is neglected. A natural fracture is used for illustration in Fig. 8.

Fig. 8. Effect of natural fracture width on capillary force.

Fig. 8 shows the relationship between capillary force and natural fracture width under different surface tension and wetting angle conditions. Capillary force decreases rapidly as width increases. When width reaches 1000nm, capillary force is only 0.1MPa ~ 0.2MPa which can be disregarded given the existence of horizontal in-situ stress difference. In addition, the volume of a natural fracture with a length of 10m, a width of 1000nm and a height of 30m is only 0.0003m³, which can be overlooked compared with the pumping rate of 2.5m³/min. Thus, after natural fracture initiation, even if fracture width changes from 10nm to 1000nm, the fracturing fluid flowing into is only parts per thousands to millions of the fracturing fluid in the hydraulic fracture because of the millimeter-level width of the hydraulic fracture compared with nanometer-level width of natural fractures. Therefore, the fluid flowing into natural fractures can be disregarded. Moreover, when the width of a natural fracture increases after initiation, a sharp drop in capillary force will occur which results in a rapid decrease of the net pressure in the natural fracture. Even when the width is 60nm, the capillary force is only about 2MPa. Therefore, considering the change in width of natural fractures, the fracture will stop propagating immediately after its initiation. In reality, however, a natural fracture may propagate for a long distance. Consequently, the width of the natural fracture is assumed to stay the same, and the fluid flowing into the natural fracture is disregarded.

In this study, we show the results of fracture network propagation by considering four natural fractures. These natural fractures are symmetric with the hydraulic fracture. Their width and length are 20nm and 1m respectively. The surface tension is 50mN/m and the wetting angle is 30degrees.

The natural fractures initiate successively after hydraulic fracture crosses. The dimensions of these four natural fractures are the same; hence, their propagation distance decreases gradually according to the order of encounter, as shown in Fig. 9. The red parts are the initial length of the natural fractures, and the blue parts are their propagation distance. Fig. 10 shows the lengths and stress intensity factors of the hydraulic and natural fractures. The natural fractures propagate rapidly during the first time of crossing and then gradually decrease. Moreover, the propagation velocity during the early stage of NF1 is faster than the others. Meanwhile, the stress intensity factors are the same at the tip of the natural fractures when hydraulic fracture encounters due to their same dimensions. However, the decrease rates after initiation, which are in accordance with propagation velocities, are different. The stress intensity factor of NF1 decreases the fastest which is identified with its propagation velocity.

Fig. 9. Schematic of fracture network propagation.

Fig. 10. Lengths and stress intensity factors of the hydraulic and natural fractures.

Figs. 11 to 15 show the influences of pumping rate, wetting angle, width, horizontal in-situ stress difference, and fracture toughness on fracture network propagation. A conclusion can be drawn that stress difference mainly affects natural fracture propagation. When the in-situ stress difference is small, natural fractures are likely to initiate and a fracture network is developed. In addition, natural fractures easily initiate and propagate at a long distance with a small wetting angle and a narrow width. Under a low pumping rate, natural fractures will propagate evenly, but the propagation distance will be short compared with that under a high pumping rate. As formation fracture toughness increases, the resistance of natural fracture propagation also increases, and fracture propagation will be difficult.

Fig. 11. Influence of pumping rate on fracture network propagation.

Wetting angle=20 degrees

Wetting angle=40 degrees

Fig. 12. Influence of wetting angle on fracture network propagation.

Width=20nm

Width=30nm

Fig. 13. Influence of natural fracture width on fracture network propagation.

Horizontal in-situ stress difference=2MPa

Horizontal in-situ stress difference=4MPa

Fig. 14. Influence of horizontal in-situ stress difference on fracture network propagation.

$$\text{Fracture toughness} = 1 \text{ MPa}\sqrt{\text{m}}$$

$$\text{Fracture toughness} = 2 \text{ MPa}\sqrt{\text{m}}$$

Fig. 15. Influence of fracture toughness on fracture network propagation.

Figs. 11 to 15 show the natural fractures propagation at the same scale. Fig. 16 illustrates the fracture network propagation in a multi-scale natural fractures reservoir. In Fig. 16a, the natural fractures are at the same initial length, and their propagation is mainly affected by fracture width. In Figs. 16b to 16d, the natural fractures propagate under different dimensions, including length and width. These figures illustrate that width rather than initial length has a more significant effect on fracture network. In reality, a fracture network develops into various forms because of the complex distribution of multi-scale natural fractures.

a

b

c

d

a: $w_{NF1}=30$ nm, $w_{NF2}=20$ nm, $w_{NF3}=15$ nm, $w_{NF4}=20$ nm ($L_{NF}=0.5$ m)

b: $w_{NF1}=30\text{nm}$, $L_{NF1}=0.5\text{m}$; $w_{NF2}=30\text{nm}$, $L_{NF2}=1\text{m}$; $w_{NF3}=15\text{nm}$, $L_{NF3}=0.5\text{m}$; $w_{NF3}=20\text{nm}$, $L_{NF4}=1\text{m}$
c: $w_{NF1}=26\text{nm}$, $L_{NF1}=0.75\text{m}$; $w_{NF2}=40\text{nm}$, $L_{NF2}=1\text{m}$; $w_{NF3}=16\text{nm}$, $L_{NF3}=0.5\text{m}$; $w_{NF3}=22\text{nm}$, $L_{NF4}=1\text{m}$
d: $w_{NF1}=38\text{nm}$, $L_{NF1}=1\text{m}$; $w_{NF2}=29\text{nm}$, $L_{NF2}=1.2\text{m}$; $w_{NF3}=26\text{nm}$, $L_{NF3}=0.8\text{m}$; $w_{NF3}=15\text{nm}$, $L_{NF4}=1\text{m}$

Fig. 16. Schematic of multi-scale fracture network propagation.

3. Experimental study

Experiments are carried out in a tri-axial hydraulic fracturing test machine (Fig. 17). The specimens are outcrops from Sichuan Province and are positioned between the pressure platens to simulate in-situ stress conditions. The injection pressure is controlled by a servo hydraulic pump of MTS 816, and the maximum capacity of the fluid injection pressure is 140MPa. Guar gum fracturing fluid is adopted for shale wettability. Phosphor is added to the fracturing fluid to observe fracture propagation morphology.

Fig. 17. Schematic of the tri-axial hydraulic fracturing test system.

3.1. Specimen preparation

Shale blocks with dimensions of $300\text{mm} \times 300\text{mm} \times 300\text{mm}$ contain many parallel beddings (Fig. 18). A central 18mm hole is drilled to a depth of 170mm parallel to the orientation of the beddings. The lengths of the wellbore and the open hole are 130mm and 40mm, respectively. The wellbore is glued to the block to prevent it from slipping from the hole during the injection of fracturing fluid, which will cause a failure. A shale block is set into the hydraulic fracturing equipment with the bedding orientation perpendicular to the maximum in-situ stress (Fig. 19). Under this condition, the hydraulic fracture will propagate in the direction of the maximum in-situ stress and cross beddings.

Fig. 18. Parallel beddings in shale.

Fig. 19. Schematic of the internal structure of a block.

Two experiments are conducted under different conditions, and the experimental parameters are listed in Table. 1. The horizontal in-situ stress difference is 3MPa and 12MPa respectively, and the other parameters are the same.

Table. 1. Parameters for the experiments.

Specimen number	σ_H (MPa)	σ_h (MPa)	σ_v (MPa)	Pumping rate (mL/min)	Fluid viscosity (mPa · s)
1	18	15	25	60	3
2	18	6	25	60	3

3.2. Experimental results

The hydraulic fracture propagates vertical to the minimum in-situ stress and crosses the beddings in the experiments. When the difference of the horizontal in-situ stress is small, fracturing fluid is liable to flow into the beddings during hydraulic fracture propagation, and a fracture network is developed. The bedding distribution of the wellbore in specimen #1 is asymmetrical, hence, the fracture morphologies are different given that two beddings are present on the left, but none is found on the right. After fracturing, a fracture network is developed on the left, whereas only a hydraulic fracture is formed on the right under similar conditions, showed in (Fig. 20). This result indicates the evident influence of beddings on hydraulic fracturing. In addition, the lower-left corner is knocked off after experiments when the block is taken down from the hydraulic fracturing system, and it is not shown in Fig. 20 to avoid misunderstandings.

Fig. 20. Result of specimen #1 under small horizontal in-situ stress difference.

When the difference in horizontal in-situ stress is large, beddings are difficult to initiate because of the small stress intensity factor at the tip of the beddings. As a consequence, the hydraulic fracture directly crosses the beddings and the beddings do not initiate during the fracturing process. In the end, only a hydraulic fracture is developed (Fig. 21). These experimental results of the influence of horizontal in-situ stress difference on fracture network propagation are in accordance with the simulation results illustrated in Fig. 14.

Fig. 21. Result of specimen #2 under a large horizontal in-situ stress difference.

Some other researchers also performed experimental studies in shale and observed fracture network morphology after hydraulic fracturing. Li (2013) prepared a cubic shale block of 300mm and used guar gum with a viscosity of 6.5mPa•s as fracturing fluid. Suarez-Rivera (2013) conducted an experiment in a cubic shale block with a side that is nearly 1.5m and used silicone oil with a viscosity of 1000mPa•s as fracturing fluid. Their experimental parameters are shown in Table. 2. To distinguish their works from the current experiments, the specimens of Li and Suarez-Rivera are numbered 3 and 4, respectively.

Table. 2. Experimental parameters in the studies of Li and Suarez-Rivera

Specimen number	σ_H (MPa)	σ_h (MPa)	σ_v (MPa)	Pumping rate (mL/min)	Fluid viscosity (mPa • s)
3	10	8	12	20	6.5
4	24	10	17	15	1000

In specimen #3, the direction of the maximum in-situ stress is perpendicular to the beddings, and the horizontal in-situ stress difference is as small as 2MPa. The pumping rate is only 20mL/min, which provides sufficient time for the beddings to absorb fracturing fluid during hydraulic fracture propagation. As shown in Fig. 22, the beddings propagate symmetrically after the hydraulic fracture crosses and a fracture network is finally developed.

Fig. 22. Fracture network in the experiment of Li.

In specimen #4 (Fig. 23), the thick blue line indicates the orientation of the wellbore, and the two

orange triangles indicate the location of fracture initiation. The wellbore is parallel to the beddings and the minimum in-situ stress. Although the horizontal in-situ stress difference is 14MPa, but the pumping rate is reduced to 15mL/min, and fluid viscosity reaches 1000mPa•s. Fluid pressure in the hydraulic fracture can be regarded as uniform due to the low fluid velocity and short distance, which is only 1.5ft in the experiment. With hydraulic fracture propagation, beddings develop against the maximum in-situ stress. The propagation length of each natural fracture varies significantly possibly because of the effect of bedding dimension, especially the width due to other conditions are completely identical. With different widths, the capillary force of the beddings varies from each other. As a result, the propagation capability of each beddings differs. The morphology of specimen #4 is resembled to the numerical simulation results of fracture network propagation presented in Fig. 16 because of capillary effect.

Fig. 23. Fracture network in the experiment of Suarez-Rivera.

4. Discussion

In real-life, natural fractures are of various geometries and cannot be orthogonal to a hydraulic fracture or in-situ stress. Therefore, the fracture interaction criteria should be taken into account. Moreover, shear stress occurs on the surface of a natural fracture and thus, the boundary element method (BEM) or extended finite element method (XFEM) is required to be adopted to solve the stress intensity factor and depict fracture propagation trajectory.

The capillary effect diminishes rapidly with increasing fracture width. When fracture width is small, the capillary effect is dominant, and fracturing fluid will be absorbed into fractures. When fracture width is large, capillary force is small, and fracturing fluid flows into natural fractures mainly because of leakage. Therefore, the volume flowing into natural fractures cannot be neglected.

During the process of experimental study, in order to coincide the model simulation results with the experiment results, the characteristics of natural fractures and shale, such as fracture width, length, and shale wetting capacity, should be measured in advance. In this research, due to the lack of these basic data of the shale specimen in Suarez-Rivera's experiment, the morphology in the experiments is resembled to rather than the same as the simulation results in our model.

5. Conclusions

(1) Multi-scale natural fractures have a significant effect on fracture network propagation. The results of the hydraulic fracturing numerical simulation that considers width heterogeneity are markedly different from those of the simulation that does not consider this factor. As a consequence, the fracture network is more complex and affected by many factors, such as natural fracture dimensions, fracturing fluid wettability, geological characteristics and working conditions.

(2) Natural fracture propagation is significantly influenced by fracture width and fracturing fluid

wettability in the presence of the capillary effect. With a small width and strong wettability, natural fractures are likely to initiate and propagate to a long distance.

(3) Horizontal in-situ stress difference affects fracture network propagation. When the stress difference is small, fracture network develops more easily. Otherwise, a hydraulic fracture will propagate predominantly. In addition, under a low pumping rate condition, the pressure drop in a hydraulic fracture is slow, which results in even propagations.

Acknowledgments

The authors are grateful to the support provided by the Chinese National Science Foundation: The Distinguished Young Scholars Program (No.51325402); Grant no.51490650.

Nomenclature and units

σ_H	Maximum horizontal in-situ stress, MPa
σ_h	Minimum horizontal in-situ stress, MPa
σ_v	Vertical in-situ stress, MPa
P_A	Pressure at crossing point of hydraulic fracture and natural fracture, MPa
P_0	Net pressure at crossing point, MPa
P_F	Net pressure of fracturing fluid in natural fracture, MPa
P_G	Net pressure of natural gas in natural fracture, MPa
$P(x)$	Net pressure distribution inside a fracture, MPa
$P_{NF}(x)$	Net pressure distribution inside natural fracture, MPa
$P_{HF}(x)$	Net pressure distribution inside hydraulic fracture, MPa
$P_{HF}^i(x)$	Average net pressure of i th element in hydraulic fracture, MPa
P_c	Capillary force, MPa
P_{x1}, P_{x2}	Net pressure at points $x=x1$ and $x=x2$ in hydraulic fracture, MPa
P_w	Net pressure at bottom hole, MPa
ΔP	Net pressure increment, MPa
x_{HF}	Distance from bottom hole to a point in hydraulic fracture, m
x_1, x_2	Distance from bottom hole to the two points in hydraulic fracture, respectively, m
σ	Gas-liquid interfacial tension, mN/m
θ	Wetting angle, degrees
w_{NF}	Natural fracture width, nm
w	Hydraulic fracture width, mm
K_I	Stress intensity factor, MPa $\cdot\sqrt{m}$
$K_{I\max}$	Maximum stress intensity factor at a propagation step, MPa $\cdot\sqrt{m}$
$K_I^{(i)}$	Stress intensity factor at i th fracture tip, MPa $\cdot\sqrt{m}$
K_{IC}	Fracture toughness, MPa $\cdot\sqrt{m}$
L_{frac}	Half-length of fracture, m
L	Length of hydraulic fracture, m
L_{NF}	Half-length of natural fracture, m
L_{NF0}	Initial half-length of natural fracture before fracturing fluid flows in, m
a	Length occupied by fracturing fluid in half-length of natural fracture, m
Δx	Length of discrete element, m
n_{NF}	Discrete element number of natural fracture, dimensionless

n_{HF}	<u>Discrete element number of hydraulic fracture, dimensionless</u>
Q	<u>Pump rate, m³/min</u>
μ	<u>Viscosity of fracturing fluid, mPa·s</u>
G	<u>Shear modulus, GPa</u>
ν	<u>Poisson's ratio, dimensionless</u>
H	<u>Hydraulic fracture height, m</u>
V	<u>Volume of hydraulic fracture, m³</u>
ΔV	<u>Volume increment during a propagation step, m³</u>
Δt	<u>Propagation time at each step, s</u>
ΔL	<u>Initial distance of hydraulic and natural fracture propagation at a step, m</u>
$\Delta \delta$	<u>Calculated distance of hydraulic and natural fracture propagation at a step, m</u>

References

- Blanton, T. L. (1982, January). An experimental study of interaction between hydraulically induced and pre-existing fractures. In *SPE Unconventional Gas Recovery Symposium*. Society of Petroleum Engineers.
- Blanton, T. L. (1986, January). Propagation of hydraulically and dynamically induced fractures in naturally fractured reservoirs. In *SPE Unconventional Gas Technology Symposium*. Society of Petroleum Engineers.
- Cheng, W., Jin, Y., & Chen, M. (2015). Reactivation mechanism of natural fractures by hydraulic fracturing in naturally fractured shale reservoirs. *Journal of Natural Gas Science and Engineering*, 23, 431-439.
- Daniels, J. L., Waters, G. A., Le Calvez, J. H., Bentley, D., & Lassek, J. T. (2007, January). Contacting more of the barnett shale through an integration of real-time microseismic monitoring, petrophysics, and hydraulic fracture design. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.
- Fan, T. G., & Zhang, G. Q. (2014). Laboratory investigation of hydraulic fracture networks in formations with continuous orthogonal fractures. *Energy*, 74, 164-173.
- Fisher, M. K., Wright, C. A., Davidson, B. M., Goodwin, A. K., Fielder, E. O., Buckler, W. S., & Steinsberger, N. P. (2002, January). Integrating fracture mapping technologies to optimize stimulations in the Barnett Shale. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.
- Gale, J. F., Reed, R. M., & Holder, J. (2007). Natural fractures in the Barnett Shale and their importance for hydraulic fracture treatments. *AAPG bulletin*, 91(4), 603-622.
- Gale, J., & Holder, J. (2008, January). Natural fractures in shales and their importance for gas production. In *Tectonics studies group annual meeting*.
- Gu, H. (1987). *Study of propagation of hydraulically induced fractures*. Texas Univ., Austin (USA).
- Gu, H., Weng, X., Lund, J. B., Mack, M. G., Ganguly, U., & Suarez-Rivera, R. (2012). Hydraulic fracture crossing natural fracture at nonorthogonal angles: a criterion and its validation. *SPE Production & Operations*, 27(01), 20-26.
- Grigg, D. A., Russell, P. E., & Griffith, J. E. (1992). Tip-sample forces in scanning probe microscopy in air and vacuum. *Journal of Vacuum Science & Technology A*, 10(4), 680-683.
- Holditch, S. A. (1979). Factors affecting water blocking and gas flow from hydraulically fractured gas wells. *Journal of Petroleum Technology*, 31(12), 1-515.

- Jacobi, D. J., Gladkikh, M., LeCompte, B., Hursan, G., Mendez, F., Longo, J., & Shoemaker, P. (2008, January). *Integrated petrophysical evaluation of shale gas reservoirs*. In *CIPC/SPE Gas Technology Symposium 2008 Joint Conference*. Society of Petroleum Engineers.
- King, G. E. (2010, January). *Thirty years of gas shale fracturing: what have we learned?*. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.
- Li, Q. (2013). *Non-planar Propagation Mechanism of Hydraulic Fracture in Shale Gas Reservoir*. China University of Petroleum, Beijing (China).
- Liang, C., Chen, M., Lu, B., Wang, J., Jin, Y., Yang, S., & Hou, B. (2014, March). The study of nano sealing to improve the brittle shale wellbore stability under dynamic load. In *Offshore Technology Conference-Asia*. Offshore Technology Conference.
- Maxwell, S. C., Urbancic, T. I., Steinsberger, N., & Zinno, R. (2002, January). Microseismic imaging of hydraulic fracture complexity in the Barnett shale. In *SPE annual technical conference and exhibition*. Society of Petroleum Engineers.
- Meyer, B. R., & Bazan, L. W. (2011, January). A discrete fracture network model for hydraulically induced fractures-theory, parametric and case studies. In *SPE Hydraulic Fracturing Technology Conference*. Society of Petroleum Engineers.
- Nestor P. 2004. Fracture Mechanics [M]. Kluwer Academic Publishers. USA
- Olson, J. E., Bahrach, B., & Holder, J. (2012, January). Examining hydraulic fracture: natural fracture interaction in hydrostone block experiments. In *SPE Hydraulic Fracturing Technology Conference*. Society of Petroleum Engineers.
- Perkins, T. K., & Kern, L. R. (1961). Widths of hydraulic fractures. *Journal of Petroleum Technology*, 13(09), 937-949.
- Renshaw, C. E., & Pollard, D. D. (1995, April). An experimentally verified criterion for propagation across unbounded frictional interfaces in brittle, linear elastic materials. In *International journal of rock mechanics and mining sciences & geomechanics abstracts* (Vol. 32, No. 3, pp. 237-249). Pergamon.
- Suarez-Rivera, R., Burghardt, J., Stanchits, S., Edelman, E., & Surdi, A. (2013, March). Understanding the effect of rock fabric on fracture complexity for improving completion design and well performance. In *IPTC 2013: International Petroleum Technology Conference*.
- Valk, P., & Economides, M. J. (1995). *Hydraulic fracture mechanics*. Wiley, New York.
- Warpinski, N. R. (1991). Hydraulic fracturing in tight, fissured media. *Journal of Petroleum Technology*, 43(02), 146-209.
- Warpinski, N. R., & Teufel, L. W. (1987). Influence of geologic discontinuities on hydraulic fracture propagation (includes associated papers 17011 and 17074). *Journal of Petroleum Technology*, 39(02), 209-220.
- Wang, F. (2008). Production fairway: speed rails in gas shale. *7th Annual Gas Shales Summit*.
- Wang, F. P., & Reed, R. M. (2009, January). Pore networks and fluid flow in gas shales. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.
- Weng, X., Kresse, O., Cohen, C. E., Wu, R., & Gu, H. (2011). Modeling of hydraulic-fracture-network propagation in a naturally fractured formation. *SPE Production & Operations*, 26(04), 368-380.
- Xu, W., Thiercelin, M. J., Ganguly, U., Weng, X., Gu, H., Onda, H. & Le Calvez, J. (2010, January). Wiremesh: A novel shale fracturing simulator. In *International Oil and Gas Conference and Exhibition in China*. Society of Petroleum Engineers.
- Yunhu, L., Mian, C., & Sheng, A. (2012). Brittle shale wellbore fracture propagation

mechanism. *Petroleum Drilling Techniques*, 40(4), 13-16.

Zhou, J., Chen, M., Jin, Y., & Zhang, G. Q. (2008). Analysis of fracture propagation behavior and fracture geometry using a tri-axial fracturing system in naturally fractured reservoirs. *International Journal of Rock Mechanics and Mining Sciences*, 45(7), 1143-1152.