
Coupled flow, stress and damage modelling of interactions between hydraulic fractures and natural fractures in shale gas reservoirs

Hai-Yan Zhu*

State Key Laboratory of Oil and
Gas Reservoir Geology and Exploitation,
School of Petroleum and Natural Gas Engineering,
Southwest Petroleum University,
610500 Chengdu, China
Email: zhuhaiyan040129@163.com

Xiao-Chun Jin*

Energy and Geoscience Institute,
University of Utah,
423 Wakara Way, Suite 300, Salt Lake City,
Utah 84108, USA
Email: xjin@egi.utah.edu
*Corresponding authors

Jian-Chun Guo

State Key Laboratory of Oil and
Gas Reservoir Geology and Exploitation,
School of Petroleum and Natural Gas Engineering,
Southwest Petroleum University,
610500 Chengdu, China
Email: guojianchun@vip.163.com

Feng-Chen An

State Key Laboratory of Petroleum Resource and Prospecting,
China University of Petroleum,
102249 Beijing, China
Email: afccup@163.com

Yong-Hui Wang

Research Institute of Petroleum Exploration
and Development-Langfang,
Petrochina, 065007 Langfang, China
Email: wyh196469@petrochina.com.cn

Xiang-dong Lai

Drilling and Production Technology Research Institute of
Chuanqing Drilling Engineering Co., Ltd.,
Petrochina, 618300 Guanghan, Sichuan, China
Email: laixiangdong@cnpc.com.cn

Abstract: Hydraulic fracturing in naturally fractured shale gas reservoirs is a typical coupled damage and seepage problem. Damage inside natural fractures, caused by either shear stress or tensile stress, can greatly increase the fracture permeability. Additional stress caused by fluid seepage bridges the connectivity among adjacent natural fractures, achieving the stimulated reservoir volume (SRV). The work couples the damage and fluid flow into the Mohr-Coulomb failure criterion for the description of the natural fractures reactivation. Hydraulic fracture is first discretised by the visco-elastic damage pore pressure cohesive elements (PPCE); then by combining the dynamic evolutions of damage, porosity and permeability, a flow, stress and damage (FSD) model of hydraulic fracture and natural fracture system is proposed. The hydraulic stimulation is successful if the permeability of the shale gas reservoir can be improved from the order of nano-Darcy to milli-Darcy. The case study on stimulated reservoir area (SRA) for Q-1 shale gas well in Sichuan Basin agrees with the field data and published data in literatures. [Received: April 6, 2015; Accepted: August 9, 2015]

Keywords: damage; hydraulic fracturing; numerical simulation; shale gas; natural fractures; shale brittleness.

Reference to this paper should be made as follows: Zhu, H-Y., Jin, X-C., Guo, J-C., An, F-C., Wang, Y-H. and Lai, X-d. (2016) 'Coupled flow, stress and damage modelling of interactions between hydraulic fractures and natural fractures in shale gas reservoirs', *Int. J. Oil, Gas and Coal Technology*, Vol. 13, No. 4, pp.359–390.

Biographical notes: Hai-Yan Zhu is a Lecturer at the Southwest Petroleum University. He received his BSc and MSc degrees in 2009 from Southwest Petroleum University. He worked for Kingdream Public Limited Company of Jiangnan oilfield as a drilling engineer during 2009 to 2010 and completed his PhD degree in Rock Mechanics in oil and gas drilling and completion from China University of Petroleum (Beijing), in 2013. His research interests include petroleum related rock mechanics, especially doing laboratory experiments and numerical simulation.

Xiao-Chun Jin is a Senior Research Scientist and Geomechanics Coordinator in the Energy and Geoscience Institute at the University of Utah. He received his BSc in Petroleum Engineering from China University of Petroleum (East China) in 2009, and his MSc and PhD degrees in Petroleum Engineering from the University of Oklahoma in 2013 and 2014, respectively. His research interests include geomechanics, onshore and offshore oil and gas, formation evaluation, geothermal resources.

Jian-Chun Guo is a Professor in the School of Petroleum and Natural Gas Engineering at the Southwest Petroleum University. He received his BSc, MSc and PhD degrees from the Southwest Petroleum University in 1992, 1995 and 1998, respectively. He is the Deputy Director of Chinese State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation. His research interests include reservoir stimulation.

Feng-Chen An is a Lecturer at the China University of Petroleum (Beijing). He received his BSc and MSc degrees from Southeast University in 2007 and 2010, and PhD degree in School of Engineering and Electronics from the University of Edinburgh in 2015. His research interests include petroleum related rock mechanics.

Yong-Hui Wang is a Senior Engineer in the Research Institute of Petroleum Exploration and Development-Langfang, Petrochina. He received his BSc degree from the Northwest University in 1986, and PhD degree from the Southwest Petroleum University in 2004. He works on reservoir stimulation.

Xiang-dong Lai is an Engineer in the Drilling and Production Technology Research Institute of Chuanqing Drilling Engineering Co., Ltd., Petrochina. He received his BSc degree from the China University of Petroleum (East China) in 2010, and BSc degree from the China University of Petroleum (Beijing) in 2013. He works on oil and gas well drilling and completion.

1 Introduction

The ultra-low permeability and various gas accumulation features render the shale gas reservoirs difficult to be developed without hydraulic fracturing treatment, except a few with highly developed natural fracture networks (Mathews et al., 2007). Study of natural fractures shows that there are not many open natural fractures in shale reservoirs (Bowker, 2007), because most of the pre-existing natural fractures are sealed by cementing materials during the diagenetic process. However, as the weak parts, these fractures can be reactivated to increase the effectiveness of hydraulic fracturing treatment. Natural fractures provide the accumulation space for natural gas. In the Barnett shale, only a small amount of the fractures can be visually identified, as are filled with calcite and quartz minerals (Rickman et al., 2008). Gas production decreases with increasing development of large fractures, indicating that they are not conducive to the preservation of shale gas. It is the densely distributed micro-fractures that play an important role in improving the reservoir performance. Essentially, the bedding structure and natural fracture system provide the necessary premise for gas accumulation and migration in shale gas reservoirs. The interconnection of the pre-existing natural fractures, bedding structure and new hydraulic fractures generated by hydraulic fracturing treatment can form complicated fracture networks, enhancing the well productivity.

For hydraulic fracturing in shale gas reservoirs, many scholars have carried out theoretical studies on whether fracture networks can be obtained and how to generate them. Hossain et al. (2000) pointed out that conventional hydraulic fracturing models do not consider the effect of natural fracture networks. The most commonly used hydraulic fracturing simulation softwares in sandstone reservoirs, such as Stimplan, MFrac, Gopher and FracProPT, all assume that the fracture is a symmetrical plane fracture without fluid loss into the natural micro- and macro-fractures (King, 2010). Based on the existing pseudo three-dimensional (P3D) model, models were developed to simulate the 3D natural fracture propagation in the shale play (Meyer and Bazan, 2011; Weng et al., 2011). The essence of these softwares are PKN, KGD or P3D models, all of which neglect the non-plane propagation process of the natural fractures and are insufficient in

describing the interactions between the hydraulic fractures and natural fractures. Therefore, these models cannot represent the physics of the natural fracture propagation. During hydraulic fracturing, the hydraulic fractures and natural fractures interfere with each other in the 3D in-situ stress field, which should be considered.

Many numerical methods, including finite element method (FEM) (Kresse et al., 2011; Nassir et al., 2010; Rahman et al., 2009), finite difference method (Nagel and Sanchez-Nagel, 2011), displacement discontinuity method (DDM) (Zhang et al., 2007, 2009), discrete element method (DEM) (Nagel et al., 2011, 2012, 2013) and the extended finite element method (XFEM) (Taleghani, 2009), have been developed to solve the interaction problem between a hydraulic fracture and the natural fractures. Besides, discrete fracture networks (DFNs) (Rogers et al., 2011; Dershowitz et al., 2010) and unconventional fracture model (UFM) (Kresse et al., 2011; Weng et al., 2011) have been built to model the hydraulic fractures and natural fractures network. Considering different approach angles of the hydraulic fracture to the natural fracture, Rahman et al. (2009), Nassir et al. (2010) and Kresse et al. (2011) studied the interaction of a hydraulic fracture with a natural fracture using the FEM. Chuprakov et al. (2011) solved the fracture propagation problem in hydraulic fracturing with pre-existing natural fractures using the DDM by applying the Mohr-Coulomb friction conditions. Deisman and Chalaturnyk (2009) put forward an adaptive calculation method that combines the continuous fluid model and the reservoir discontinuous model with natural fracture networks. Damjanac et al. (2010) established a hydraulic fracturing model based on DEM for reservoirs with natural fractures, and reached that compressible fluid can produce complicated fracture networks. Nagel et al. (2011, 2012) meshed the shale matrix into discrete rigid micro-elements using UDEC and 3DEC software, and pre-existing natural fractures were assigned between the rigid microelements. The XFEM can describe the non-plane fracture propagation behaviour resulting from the changing in-situ stresses. Taleghani (2009) developed an XFEM code to simulate the hydraulic fracture propagation in fractured reservoirs. The hydraulic fracturing module of Abaqus is capable of simulating fracture initiation and propagation as well as fracturing fluid flow within the hydraulic fracture using visco-elastic continuum damage model of the PPCE. Simulation results of 2D radial fracture initiation and propagation by Chen et al. (2009) using the PPCE are fully consistent with the analytical solution of K-vertex. Yao et al. (2010) also modelled the hydraulic fracturing in plastic formation using PPCE and found that results of Abaqus are closer to the analytical solution than those from pseudo P3D model and PKN model. Zhang et al. (2010), taking the effects of casing, cement sheath, micro-annulus and perforation holes into consideration, studied the hydraulic fracture propagation mechanism of horizontal wells using 3D PPCE. All these models are of great significance for designing hydraulic fracturing and understanding fracture networks propagation mechanism in shale gas reservoirs. However, the coupled propagation of hydraulic fractures and natural fractures, and the influence of natural fractures on hydraulic fractures are seldom investigated.

This paper treats the natural micro-fractures sealed by cementing materials as weak parts with lower Young's modulus and strength than shale matrix, and the fracture networks are mainly created by shear or tensile damage during large-scale hydraulic fracturing. As the hydraulic fracture propagates, the fracturing fluid squeezes the natural fracture surfaces, resulting in shear slip within the weakly cemented natural fractures. The consequent plastic damage caused by shear slip weakens the natural fractures and increases the permeability and porosity of the natural fractures (Zhu and Wong, 1999),

thus linking up the hydraulic fractures and the natural fractures. Using the continuum damage mechanics principle, the plastic damage and fluid seepage in natural fractures are coupled and introduced into the Mohr-Coulomb failure criterion. With the dynamic evolution of tensile stress, porosity and permeability of natural fractures, hydraulic fracture propagation is simulated by the visco-elastic damage PPCE; afterwards, the elasto-plastic damage finite element model of hydraulic fracture propagation in shale reservoirs is established. The plastic damage, porosity and permeability evolution equations are achieved using the secondary development function of the finite element commercial software subroutine. Here, the permeability is selected as the criterion of whether the fracture networks are effectively created or not. If the permeability of the shale gas reservoirs can be increased from the order of nano-Darcy to milli-Darcy, the hydraulic fracturing treatment is considered as successful. The effects of natural fracture distribution, in-situ stress ratio, shale Young's modulus, shale Poisson's ratio, shale cohesive strength, and cohesive strength and internal friction angle of natural fractures on SRA (the area of stimulated natural fracture zone) have been assessed to identify the mechanisms of the fracture networks growth. This work provides a theoretical guidance for hydraulic fracturing design in shale gas reservoirs.

2 The governing equations

2.1 Fluid-solid coupling equations

Fluid flow obeys the continuity equation, and the rock mechanical properties are simulated by constitutive model of effective stress.

The relationship between effective stress and total stress is:

$$\bar{\sigma} = \sigma + p_w I \quad (1)$$

where $\bar{\sigma}$ is the effective stress matrix; σ is the total stress matrix; I is a second-order unit tensor, p_w is the absolute value of pressure.

The control volume is V with the surface area of S . The rock matrix stress equilibrium equation is (Zhu et al., 2013):

$$\int_V \delta \hat{\epsilon}^T \sigma dV = \int_{S_\sigma} \delta v^T t dS + \int_V \delta V^T \hat{f} dV \quad (2)$$

where σ is the stress matrix; $\delta \hat{\epsilon}$ is the virtual strain rate matrix; t is surface force vector; $\hat{f}$ is the body force vector and δ_v is the virtual displacement vector.

Discretisation of the stress equilibrium equation gives the finite element meshes of the solid material, through which the fluid flows. Fluid flow should satisfy the continuity equation:

$$\frac{1}{J} \frac{\partial}{\partial t} (J \rho_w n_w) + \frac{\partial}{\partial x} (\rho_w n_w v_w) = 0 \quad (3)$$

where J is the volume changeable ratio of porous medium; ρ_w is fluid density; n_w is void ratio; x is space vector, and v_w is fluid seepage velocity, which obeys Darcy's law:

$$v_w = -\frac{1}{n_w g \rho_w} J \cdot \left(\frac{\partial p_w}{\partial x} - \rho_w g \right) \quad (4)$$

where g is gravitational acceleration, p_w is fluid pressure.

As can be seen from the above equations, the rock matrix stress and the pore fluid pressure are nonlinearly coupled with each other, forming a control equation. After being converted into an equivalent weak form integral, it can be solved by the FEM.

2.2 *Elasto-plastic damage model of natural fractures*

Plasticity refers to the frictional sliding on the interior surface of micro-fractures or joint planes; and damage means the initiation and propagation of the fractures. Tang et al. (2002), Yang et al. (2004) and Wang et al. (2009) conducted research on an FSD coupling model for rock failure and hydraulic fracturing within heterogeneous geo-materials. Jia et al. (2009) proposed an FSD model for boom clay during tunnelling. Herein, similar FSD model is used.

2.2.1 *Elasto-plastic damage model*

According to the effective stress and strain equivalence principle of the continuum damage mechanics, the elasto-plastic damage model of natural fractures can be expressed as:

$$\{d\varepsilon\} = \{d\varepsilon_e\} + \{d\varepsilon_p\} + \{d\varepsilon_d\} \quad (5)$$

where $\{d\varepsilon\}$ is the total strain; $\{d\varepsilon_e\}$ is elastic strain; $\{d\varepsilon_p\}$ is plastic strain, and $\{d\varepsilon_d\}$ is damage strain. The elastic strain can be written as:

$$\{d\varepsilon_e\} = [K^*]^{-1} \{d\sigma\} \quad (6)$$

where $[K^*] = (1 - D)[K]$, D is damage factor; $[K]$ is elastic matrix.

The yield function F and plastic potential function G of damaged fractures are:

$$F(\sigma, H(\chi), D) = 0 \quad (7)$$

$$G(\sigma, H(\chi), D) = 0 \quad (8)$$

where σ is stress; χ , as the scalar of internal variable, indicates the equivalent plastic strain; H describes the softening and hardening of material during the plastic deformation.

If the plastic deformation and damage of natural fractures occurs simultaneously, the plastic strain and damage strain can be expressed as:

$$\{d\varepsilon_p\} + \{d\varepsilon_d\} = \lambda \left\{ \frac{\partial G(\sigma, H(\chi), D)}{\partial \sigma} \right\} \quad (9)$$

where λ is a positive value, defined by the material hardening law:

$$\lambda = \frac{\left\{ \frac{\partial F}{\partial \sigma} \right\}^T [K^*] \{d\varepsilon\}}{\left\{ \frac{\partial F}{\partial \sigma} \right\}^T [K^*] \left\{ \frac{\partial G}{\partial \sigma} \right\} - A} \quad (10)$$

where A is a hardening parameter.

According to classic plastic theory, the plastic matrix of damaged material can be calculated from:

$$[D_p^*] = \frac{[K^*] \left\{ \frac{\partial G}{\partial \sigma} \right\} \left\{ \frac{\partial F}{\partial \sigma} \right\}^T [K^*]}{\left\{ \frac{\partial F}{\partial \sigma} \right\}^T [K^*] \left\{ \frac{\partial G}{\partial \sigma} \right\} - A} \quad (11)$$

2.2.2 Modified Mohr-Coulomb failure criterion

The rock effective shear strength parameters c^* and ϕ^* are functions of the damage factor D . Under the comprehensive effect of damage and pore pressure, Mohr-Coulomb failure criterion can be represented with effective stress, pore pressure and effective shear strength:

$$\frac{\tau_n}{1-D} = c^* + \frac{\sigma_n + DP_w}{1-D} \tan \phi^* \quad (12)$$

where σ_n is the normal stress on failure surface; τ_n is the shear stress on failure surface; p_w is pore pressure.

If σ_c is the uniaxial compressive strength of rock, then the damaged uniaxial strength is $\sigma_c^* = (1-D)\sigma_c$. According to the Mohr-Coulomb criterion, the relationship between c^* , ϕ^* and σ_c is:

$$\sigma_c^* = (1-D)\sigma_c = \frac{2c^* \cos \phi^*}{1 - \sin \phi^*} \quad (13)$$

It can be seen that effective shear strength parameters of the damaged rock c^* and ϕ^* can be expressed as functions of normal stress, tangential stress, uniaxial compressive strength, and damage factor.

2.2.3 Damage evolution equations of natural fractures

2.2.3.1 Tensile damage of natural fractures

In this paper, compressive stress (strain) is defined as negative and tensile stress (tensile strain) is positive. Under the uniaxial tensile stress condition, damage evolution follows (Tang et al., 2002):

$$D = \begin{cases} 0 & 0 < \bar{\varepsilon} \leq \varepsilon_{t0} \\ 1 - \lambda S_t / \bar{\varepsilon} E_0 & \varepsilon_{t0} < \bar{\varepsilon} \leq \varepsilon_{tu} \\ 1 & \varepsilon_{tu} < \bar{\varepsilon} \end{cases} \quad (14)$$

where λ is the residual strength coefficient; E_0 is Young's modulus of undamaged natural fractures; ε_{t0} is tensile strain corresponding to the elastic limit; ε_{tu} is the maximum tensile strain of natural fractures; $\bar{\varepsilon}$ can be computed with:

$$\bar{\varepsilon} = \sqrt{\langle -\varepsilon_1 \rangle^2 + \langle -\varepsilon_2 \rangle^2 + \langle -\varepsilon_3 \rangle^2} \quad (15)$$

where ε_1 , ε_2 , and ε_3 are the three principal strains, respectively. The expression $\langle x \rangle$ can be segmented as:

$$\langle x \rangle = \begin{cases} x & x \geq 0 \\ 0 & x < 0 \end{cases} \quad (16)$$

2.2.3.2 Shear damage of natural fractures

Under the coupled effect of stress and pore pressure, plastic deformation occurs in natural fractures once the strength exceeds its limit. The equivalent plastic strain can be calculated by:

$$\bar{\varepsilon}_p = \frac{\sqrt{2}}{3} \sqrt{(\varepsilon_{p1} - \varepsilon_{p2})^2 + (\varepsilon_{p2} - \varepsilon_{p3})^2 + (\varepsilon_{p3} - \varepsilon_{p1})^2} \quad (17)$$

where ε_{p1} , ε_{p2} and ε_{p3} are the three principal plastic strains, respectively.

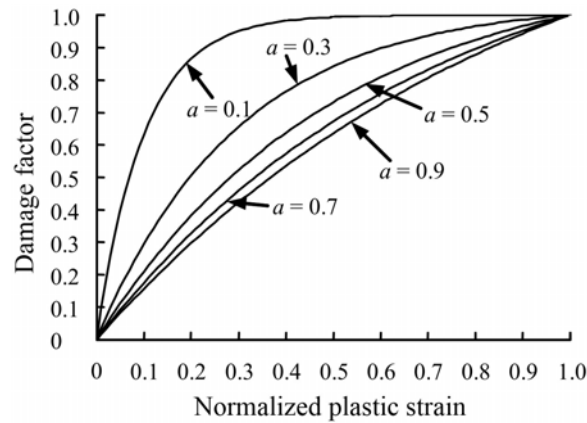
Damage factor and equivalent plastic strain fit with the first-order exponential decay relationship:

$$D = A_0 e^{-\bar{\varepsilon}_{pn}/a} + B_0 \quad (18)$$

where $\bar{\varepsilon}_{pn}$ is the normalised equivalent plastic strain; a , as a material parameter, can be

determined by experiments; $A_0 = \frac{1}{e^{-1/a} - 1}$; $B_0 = -\frac{1}{e^{-1/a} - 1}$.

Figure 1 Damage factor and the normalised plastic strain



Source: Jia et al. (2009)

Under the stress of high pressure fracturing fluid, natural fractures go through continuous plastic deformation. Its damage behaviour can be described by introducing the maximum equivalent plastic strain failure criterion. Once the equivalent plastic strain of the natural fracture exceeds the maximum value $\bar{\epsilon}_{pmax}$, the fracture breaks due to the extreme plastic deformation. Lacking of experimental data, 20% is assigned as the maximum equivalent plastic strain by referring to the mechanical properties of Belgium shale. If $\bar{\epsilon}_p > \bar{\epsilon}_{pmax}$, damage occurs, and $a = 0.2$. Now, in the damage evolution equation (18), a is the only unknown variable. The relationship between the damage factor and the plastic strain is depicted in Figure 1, as is obvious that a quantifies the evolution rate of the damage factor with respect to the normalised plastic strain.

2.2.4 Permeability evolution equation of natural fractures

2.2.4.1 Permeability evolution equation of undamaged natural fractures

The change in void ratio attributes to the deformation of rock matrix. Porosity and volumetric strain can be correlated by:

$$n = 1 - \frac{1 - n_o}{\epsilon_v} \quad (19)$$

where n_o is the initial porosity, ϵ_v is the volumetric strain.

The relationship between permeability coefficient and porosity is:

$$k = \frac{\rho g}{\mu} \frac{d^2}{180} \frac{n^3}{(1 - n)^2} \quad (20)$$

where μ is the fluid dynamic viscosity; d is the diameter of solid particles. Integration of these two equation yields the relationship between permeability coefficient and volumetric strain (Zhu et al., 2013):

$$k = k_0 \left[\left(\frac{1}{n_0} \right) (1 + \epsilon_v)^3 - \left(\frac{1 - n_0}{n_0} \right) (1 + \epsilon_v)^{-1/3} \right]^3 \quad (21)$$

where k_0 is the initial permeability coefficient.

2.2.4.2 Permeability evolution equation of damaged natural fractures

It has been found that when the testing load exceeds the maximum strength of rock specimen, its permeability and porosity increase abruptly (Zhu and Wong, 1999). Charlez (1991), through hydraulic fracturing experiments, obtained that as the fluid pressure increases and micro-fractures develop, the influence of permeability changes on stress field is obvious. Yale et al. (2000) pointed out that most of the hydraulic fracturing models did not consider the interaction of damage with permeability, thus bringing about a certain degree of calculation error. The damaged natural fractures can still bear some shear load and pore pressure. Provided the volume of porous medium as V , the damaged volume can be calculated with:

$$V_D = V(1 - n)D \quad (22)$$

where n is the rock porosity.

In accordance with the seepage cube law, the damaged permeability coefficient evolves as follows (Jia et al., 2009):

$$k = (1 - D)k_0 + Dk_f (1 + \varepsilon_V^{PF})^3 \quad (23)$$

where k_0 is the undamaged rock permeability coefficient; k_f is the damaged rock permeability coefficient; ε_V^{PF} is the volumetric plastic strain.

Assume that damage does not occur in elastic deformation, and plastic strain and damage happen at the same time, then:

$$\varepsilon_V^{PF} = D\varepsilon_V^P \quad (24)$$

where ε_V^P is volumetric plastic strain.

2.3 Visco-elastic damage model of the PPCE

2.3.1 Damage evolution model of the PPCE (Dassault Systèmes, 2014)

The PPCE constitutive equation can be expressed as:

$$\begin{Bmatrix} t_n \\ t_s \\ t_t \end{Bmatrix} = \frac{E(1-\nu)}{(1+\nu)(1-2\nu)} \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1-2\nu & 0 \\ 0 & 0 & \frac{1-2\nu}{2(1-\nu)} \end{bmatrix} \begin{Bmatrix} \varepsilon_n \\ \varepsilon_s \\ \varepsilon_t \end{Bmatrix} \quad (25)$$

where t_n , t_s and t_t are the normal stress and two tangential stresses, respectively; and ε_n , ε_s and ε_t are the normal strain and two tangential strains, respectively.

The traction-separation criterion of PPCE is used to determined the fracture initiation and propagation. Damage is assumed to initiate when a quadratic interaction function involving the nominal stress ratios in equation (26) equals one (Yao et al., 2010):

$$\left\{ \frac{\langle t_n \rangle}{t_n^0} \right\}^2 + \left\{ \frac{t_s}{t_s^0} \right\}^2 + \left\{ \frac{t_t}{t_t^0} \right\}^2 = 1 \quad (26)$$

where t_t^0 is the tensile strength of PPCE, t_s^0 and t_t^0 are shear strengths in two tangential directions.

The PPCE damage evolution model is:

$$\begin{aligned} t_n &= \begin{cases} (1-D)\bar{t}_n, & \bar{t}_n \geq 0 \\ \bar{t}_n, & \bar{t}_n < 0 \end{cases} \\ t_s &= (1-D)\bar{t}_s \\ t_t &= (1-D)\bar{t}_t \end{aligned} \quad (27)$$

where $\bar{t}_n$, $\bar{t}_s$ and $\bar{t}_t$ are stresses in three directions of PPCE in undamaged stage with linear elastic deformation. If the damage factor D is 1, the PPCE loses its strength completely.

With the linear damage evolution criterion, the damage factor is calculated as follows (Turon et al., 2006):

$$D = \frac{d_m^f (d_m^{\max} - d_m^0)}{d_m^{\max} (d_m^f - d_m^0)} \quad (28)$$

where $d_m^{\max}$ is the maximum displacement of the element; d_m^f is the displacement when element fails; d_m^0 is the displacement when element damage initiates.

2.3.2 Fluid flow within cohesive element

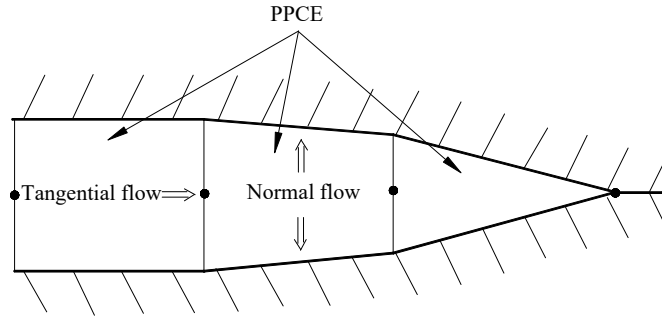
2.3.2.1 Tangential flow

Fluid within cohesive element flows along the normal and tangential directions, as shown in Figure 2. Fluid of tangential flow is generally treated as Newtonian and power law fluid. Here, power law fluid is selected to characterise the flow of the fracturing fluid, the constitutive equation of which is:

$$\tau = K' \dot{\gamma}^{n'} \quad (29)$$

where τ is the fluid tangential stress, $\dot{\gamma}$ is the tangential strain rate, K' is the fluid consistency; n' is the power-law coefficient.

Figure 2 Fluid flow in cohesive element



The volume flow rate of tangential flow within cohesive element can be expressed as:

$$qd = \left(\frac{2n'}{1+2n'} \right) \left(\frac{1}{K'} \right)^{\frac{1}{n'}} \left(\frac{d}{2} \right)^{\frac{1+2n'}{n'}} |\nabla p|^{\frac{1-n'}{n'}} \nabla p \quad (30)$$

2.3.2.2 Normal flow

Normal flow within PPCE takes the form of fluid loss through the upper and lower element surfaces, as can be calculated by:

$$\begin{cases} q_t = c_t (p_i - p_t) \\ q_b = c_b (p_i - p_b) \end{cases} \quad (31)$$

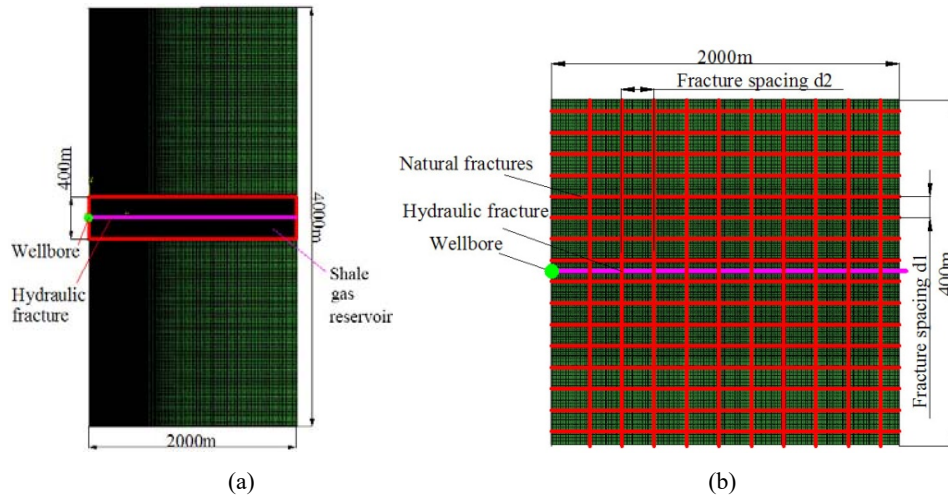
where q_t , q_b are normal flow rates into the upper and lower surfaces of the cohesive elements, respectively; c_t , c_b are the fluid loss coefficients of the upper and lower surfaces in $\text{m}/(\text{Pa}\cdot\text{s})$, respectively; The fluid loss coefficients that are input as either constants or functions of field variables by the user can be interpreted as the effective permeability of a finite layer on the cohesive element surfaces (Chen et al., 2009; Chen, 2012). p_t , p_b are pore pressures on upper and lower surfaces of the cohesive element, respectively; p_i is the fluid pressure in the cohesive zone.

3 FSD model for hydraulic fracturing in shale gas reservoirs

3.1 FSD model

As shown in Figure 3, the whole size of the model is $2,000 \text{ m} \times 4,000 \text{ m}$, and the shale gas reservoir is $400 \text{ m} \times 2,000 \text{ m}$. Due to the symmetry, only half of the formation in x direction is utilised. The natural fracture distribution in the reservoir is shown in Figure 3(b), where two sets of orthogonal natural fractures are allocated. The fracture spacing in y -direction and x -direction are $d1$ and $d2$, respectively. Hydraulic fracture is meshed by visco-elastic damage model of the PPCE. The PPCE size along the fracture path is 0.2 m .

Figure 3 FSD model of fracture propagation for hydraulic fracturing in shale gas reservoirs, (a) total model (b) natural fracture networks (see online version for colours)



The upper, lower and right boundaries of the model are constrained by the original formation pore pressure. Before simulation, the maximum, minimum horizontal stresses, and the pore pressure are assigned to each node inside the model to mimic the original stress state. Then, the viscous hydraulic fracturing fluid is injected into the nodes through the wellbore with a certain flow rate. The initial length of opened hydraulic fracture set in the model is 0.6 m , which is the length of the perforations.

To verify the accuracy and reliability of the model, the cohesive element size must be smaller than the length l_z of the cohesive zone. In mode-I fracture under plane strain condition, l_z can be expressed as (Rice, 1980):

$$l_z = \frac{9\pi K_{IC}^2}{32(t_n^o)^2} = \frac{9\pi E G_c}{32(1-\nu^2)(t_n^o)^2} \quad (32)$$

where K_{IC} is the mode-I fracture toughness, E is the Young's modulus, and G_c is the cohesive energy.

For the parameters of G_c , t_n^o , the initial cohesive stiffness K_0 , the critical displacement at complete failure d_n^f , and the critical displacement at damage initiation d_n^0 , only three of them are independent, they are correlated by Chen (2012) and Chen et al. (2009):

$$G_c = \frac{1}{2} t_n^o d_n^f = \frac{1}{2\alpha} t_n^o d_n^0 = \frac{(t_n^o)^2}{2\alpha K_0} \quad (33)$$

where $\alpha = d_n^0 / d_n^f$.

Table 1 Reservoir petrophysical and mechanical parameters

Formation	Young's modulus /GPa	Poisson ratio/	Permeability /nD	Porosity /%	Pore pressure /MPa	Cohesive strength /MPa	Internal friction angle /°
Parameters	30	0.2	200	5	7.8	27	30

The reservoir petrophysical and mechanical parameters are summarised in Table 1, which are based on the shale gas reservoir data of Sichuan Basin. The overburden stress, maximum horizontal stress, minimum horizontal stress and pore pressure are 21, 38, 18, and 7.8 MPa, respectively. The formation permeability coefficient is 5e-9 m/s; void ratio is 0.06; and saturation is 1. The pumping rate is 14 m³/min; fracturing fluid viscosity is 0.2 Pa·s; fracturing fluid loss coefficient is 1e-10 m³/(Pa·s). The fracture networks are studied at three time points of 20, 50 and 100 minutes. The effect of proppants on hydraulic fracture propagation can be represented by increasing the fracturing fluid viscosity. The relationship between proppant concentration c and fluid viscosity μ is (Barree and Conway, 1994):

$$\mu = \mu_0 \left(1 - \frac{c}{0.65} \right)^{-1.7} \quad (34)$$

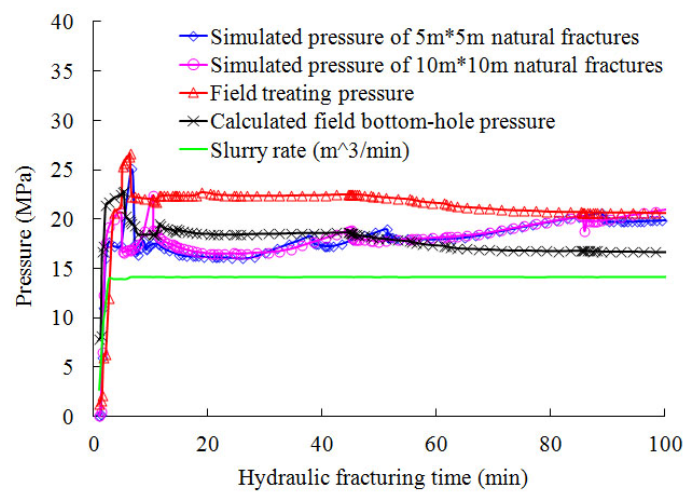
Table 2 PPCE parameters

PPCE	K_{nn}/GPa	K_{ss}/GPa	K_{tt}/GPa	$\bar{t}_n / MPa$	$\bar{t}_s / MPa$	$\bar{t}_t / MPa$	d_n^0 / mm
Parameters	27.6	11.4	11.4	15.6	15.6	15.6	5

Based on equations (32) and (33), the PPCE parameters are given in Table 2. The parameters are further verified by the field measured bottom-hole pressure. The proppant concentration c is obtained from the field data. The proppant concentration is calculated by a function of time. The average proppant concentration is about 10% during the

hydraulic fracturing. The simulated bottom-hole pressure curves of $5\text{ m} \times 5\text{ m}$ and $10\text{ m} \times 10\text{ m}$ fractures are compared with field measured pressure in Figure 4. With the same pumping rate, the simulated fracture initiation and propagation pressure agree with the field measurements. The fracture initiation pressure deviation is less than 2 MPa, and that of propagation pressure is less than 3.8 MPa, indicating that the model is feasible for simulating hydraulic fracturing in shale gas reservoirs. These differences are affected by the distribution of natural fractures. By optimising the natural fracture spacing to simulate their in-situ distribution, the accuracy of the model can be improved.

Figure 4 Simulated bottom-hole pressure and field measured pressure during hydraulic fracturing (see online version for colours)



3.2 Results and discussion

Take a $10\text{ m} \times 10\text{ m}$ block for example, Figure 5 shows the hydraulic fracture geometry after 100 minutes. The fracture width on wellbore is 2.82 cm, with the half length of 207 m. The shear damage, equivalent plastic strain and permeability coefficient of natural fractures, as delineated in Figures 6–8, present very similar patterns. Tensile failure mainly occurs in the hydraulic fracture, as shown in Figure 9.

Figure 5 Geometry of hydraulic fracture in shale gas reservoir (see online version for colours)

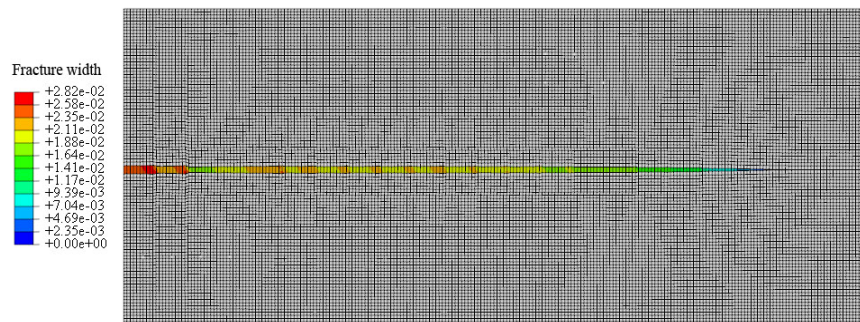
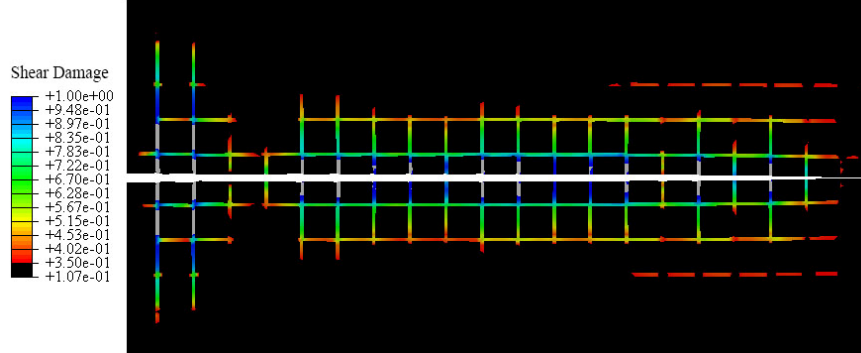
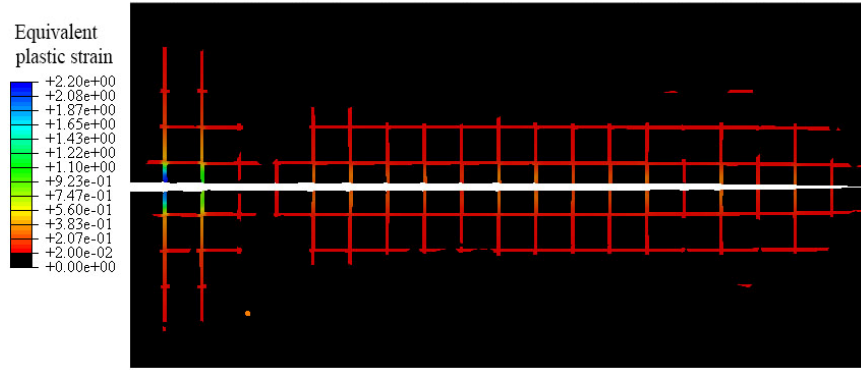
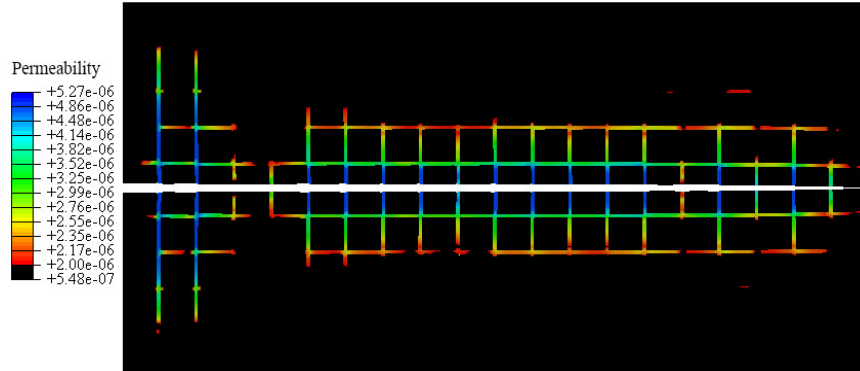
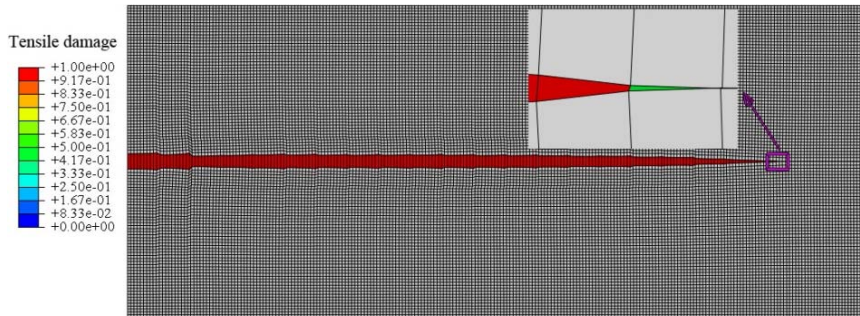


Figure 6 Shear damage of natural fractures (see online version for colours)**Figure 7** Equivalent plastic strain of natural fractures (see online version for colours)

As shown in Figure 6, natural fractures primarily undergo shear failure. It can be seen that around and behind the hydraulic fracture tip, damage area (Figure 6) and equivalent plastic strain (Figure 7) are relative large. Shear stress presents behind the hydraulic fracture tip, and complicated fractures occur only around and behind the hydraulic fracture tip, which is caused by stress shadow around the hydraulic fracture tip. In Figure 6 on the left side, at the initial stage of hydraulic fracturing, the stimulated length of natural fractures behind hydraulic fracture tip is about 60 m. Nagel et al. (2011, 2013) have pointed out that “Clearly, the bulk of the tensile failure has occurred along the plane of the created hydraulic fracture. In contrast, the bulk of shear failure has occurred within the natural fracture system.” In Figure 6 and Figure 7, the results also show that the shear damage of natural fractures has occurred within the natural fracture system, and no tensile failure is seen in the natural fracture system. The tensile failure has occurred along the created hydraulic fracture plane. When the hydraulic fracture length reaches 10 m, the stimulated natural fractures on both sides of the hydraulic fracture widen up to 72 m. If the natural fracture permeability coefficient attains $2\text{e-}6$ m/s, i.e. 1 mD, the hydraulic fracturing treatment is successful. Figure 8 displays that the stimulated length of natural fractures is about 200 m, with the width of about 35 m, thus the SRA reaches $7,000\text{ m}^2$.

Figure 8 Permeability coefficient of natural fractures (see online version for colours)**Figure 9** Tensile damage of hydraulic fracture (see online version for colours)

4 Influential parameters of SRA

4.1 The effect of natural fracture distribution

As shown in Figure 10, with the same pumping rate, the smaller the natural fracture spacing, the larger the hydraulic fracture half-length, but the smaller the hydraulic fracture width achieved. Figure 11 shows that if the fracture spacing goes narrower, the SRA of the natural fractures are much smaller. According to the fracture mechanics theory, certain fracture energy makes certain fractures initiation and propagation in specific conditions. If the stress shadow effects are neglected, the fracture initiation and propagation energy for each length is the same. However, when the natural fracture spacing goes narrower, the stress shadow interferences of each natural fracture becomes much stronger, much energy is needed to break the fracture. Thus, to obtain the same SRA, much energy is needed, which means that larger pumping rate is required for narrower natural fracture spacing. That's why large-scale hydraulic fracturing is needed to create a large SRV in shale gas reservoirs. For the restriction of the fracturing pump, the slurry rate is usually 15 cubic metre per minute and the totally hydraulic fracturing fluid is about 2,500–3,000 cubic metre per one hydraulic fracturing stage. If the shale gas well is more than 3,000 metre depth (such as the shale gas reservoir in Sichuan Basin, China), larger fracturing pump is needed to break the shale. This is not available, because

there is no much larger fracturing pump and the water resource is limited in the mountain area in Sichuan Basin.

Figure 10 The influence of natural fracture distribution on hydraulic fracture geometry (see online version for colours)

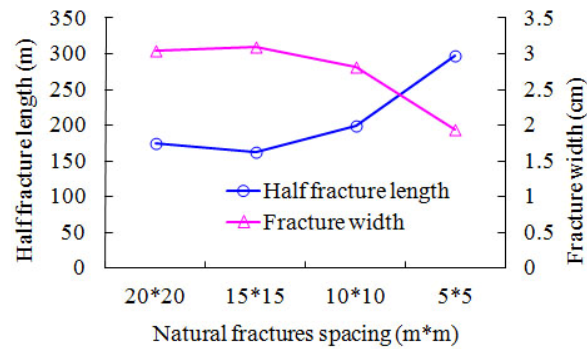


Figure 11 The influence of natural fracture distribution on the SRA (see online version for colours)

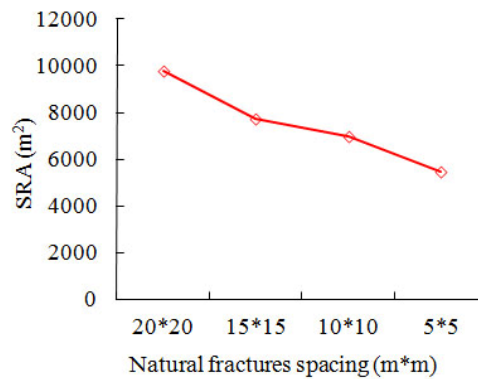


Figure 12 The SRA of 20 m × 20 m natural fractures (see online version for colours)

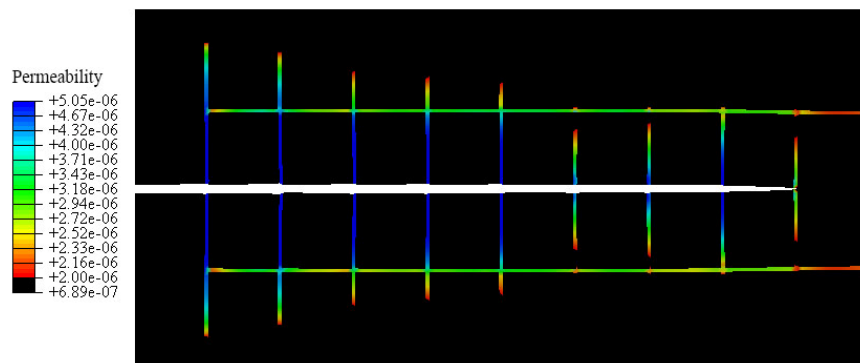
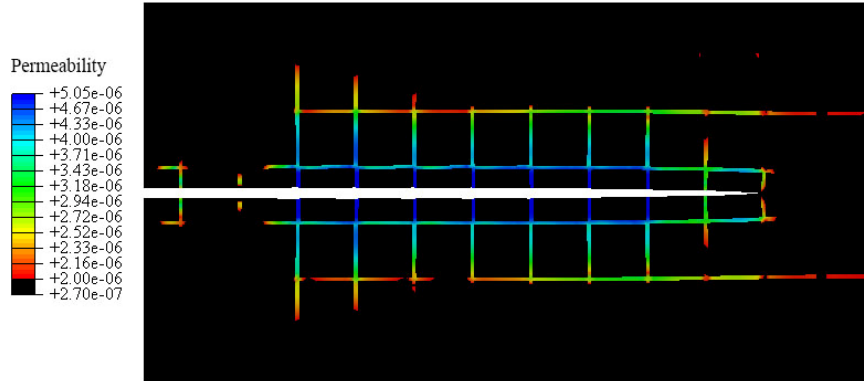
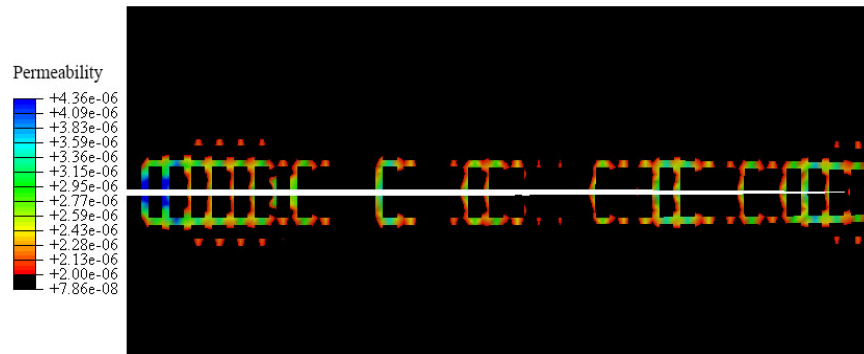


Figure 13 The SRA of $15\text{ m} \times 15\text{ m}$ natural fractures (see online version for colours)**Figure 14** The SRA of $5\text{ m} \times 5\text{ m}$ natural fractures (see online version for colours)

As shown in Figure 12, Figure 13, Figure 8 and Figure 14, where the natural fracture spacing is $20\text{ m} \times 20\text{ m}$, $15\text{ m} \times 15\text{ m}$, $10\text{ m} \times 10\text{ m}$ and $5\text{ m} \times 5\text{ m}$, shear stress failures all occur behind the hydraulic fracture tip. The SRA of natural fractures decreases with the decrease of natural fracture spacing. When natural fracture spacing is $5\text{ m} \times 5\text{ m}$, SRA is very small. Besides, the smaller the fracture spacing, the more shear fractures around the wellbore are created, and the larger the propagation pressure is needed.

4.2 The effect of in-situ stress ratio

As can be seen in Figures 15–17, where the natural fracture spacing is $10\text{ m} \times 10\text{ m}$ and the minimum horizontal stress is 18 MPa, the effect of in-situ stress ratio on stimulated field around the nature fractures is significant, in that with the increase of the maximum horizontal stress, the SRA decreases. Also, as the maximum horizontal principle stress decreases, the shear fractures turn to the direction of the minimum horizontal stress; meanwhile some fractures are induced on the orthogonal surfaces of the shear fractures, proliferating more micro-seismic events.

Figure 15 The SRA of natural fractures with horizontal stress ratio of 2 (see online version for colours)

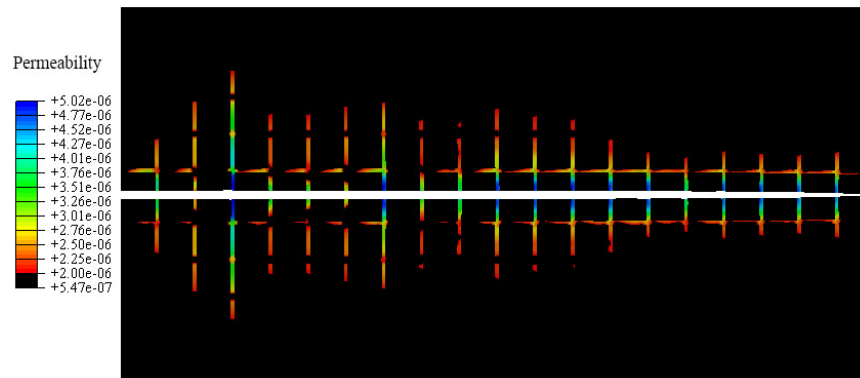


Figure 16 The SRA of natural fractures with horizontal stress ratio of 1.5 (see online version for colours)

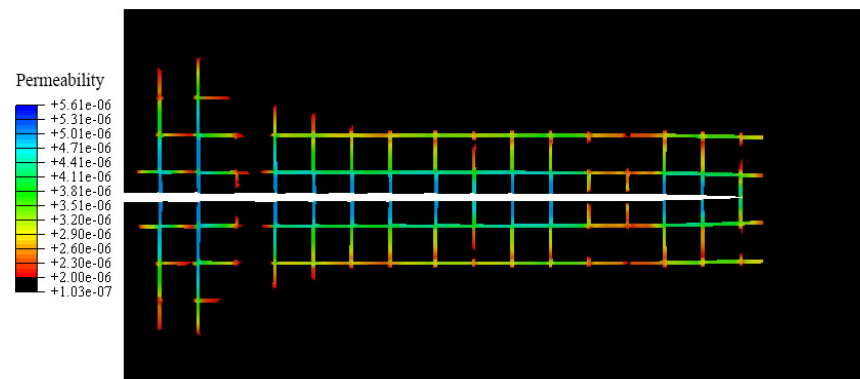


Figure 17 The SRA of natural fractures with horizontal stress ratio of 1 (see online version for colours)

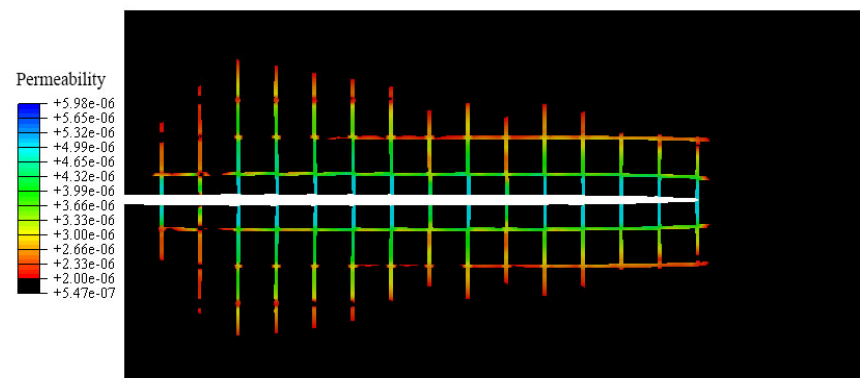


Figure 18 shows that, with decreasing horizontal stress ratio, the half-length and width of hydraulic fracture decreases and increases respectively, indicating that large stress ratio can facilitate the hydraulic fracture propagation. Figure 19 further explains as stress ratio decreases, SRA of natural fractures increases, and thus the micro-seismic response would be more obvious. It can be concluded that the influence of horizontal stress ratio on hydraulic fracturing in naturally fractured shale reservoirs is much greater than that in homogeneous ones. High stress ratio can accelerate the fracture turning toward the maximum horizontal stress direction in homogeneous formation, making the fracture surface much smoother. When the stress ratio varies from 1.5 to 1, the stimulated fractures become much more complicated when the ratio decreases. Doe and Boyce (1989) carried out a laboratory hydraulic fracturing experiment on salt. They found that: when the stress ratio is more than 1.5, the fracture is a single plane fracture; when the stress ratio varies from 1.5 to 1, the branched fractures and multi-fractures appear, the fractures become much more complicated when the ratio decreases. Behrmann and Elbel (1991) and Zhu et al. (2014) did the hydraulic fracturing experiments under the stress ratio of 1.22, they also found the complicated fractures. These experiments results are in consistence with the results in Figure 19.

Figure 18 The influence of in-situ stress ratio on hydraulic fracture geometry (see online version for colours)

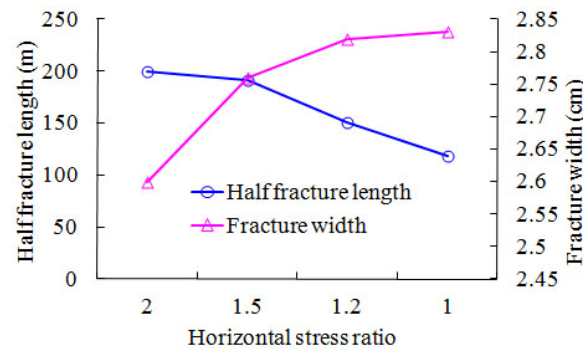
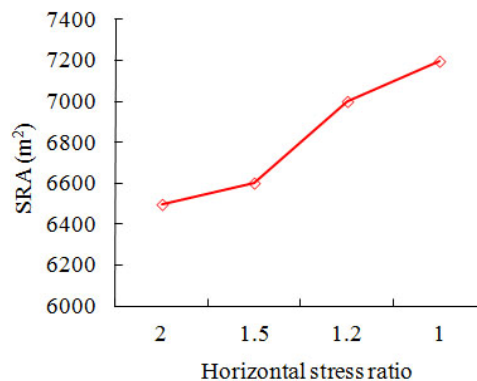


Figure 19 The influence of in-situ stress ratio on the SRA (see online version for colours)



4.3 The effect of internal friction angle of natural fractures

By setting the internal friction angle of natural fractures as 10° , 20° , 30° and 40° , and the hydraulic injection time at 20 minutes, the fracture geometries are simulated. Figure 20 indicates that smaller internal friction angle can lead to more complicated fracture patterns, higher fracture propagation pressure as well as more shear fractures. As shown in Figure 21, the changes of hydraulic fracture half-length and width with the internal friction angles are relatively gradual. Figure 22 illustrates that the smaller the internal friction angle, the larger the SRA of natural fractures can be achieved, manifesting that the internal friction angle is a key factor in influencing the SRV. When the half fracture length is the larger, the fracture width is the smaller. It indicates that there is a great relationship between the number of shear fractures and internal friction angles of the natural fractures.

Figure 20 Influence of internal friction angle on SRA of natural fractures, (a) internal friction angle is 10° (b) internal friction angle is 20° (c) internal friction angle is 30° (d) internal friction angle is 40° (see online version for colours)

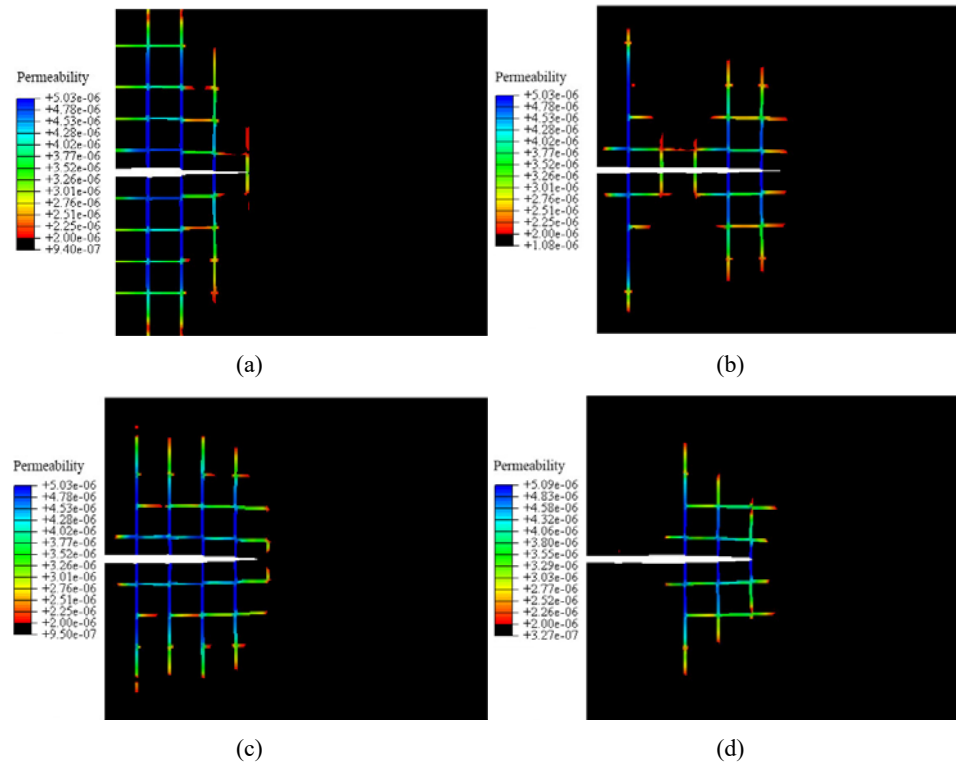
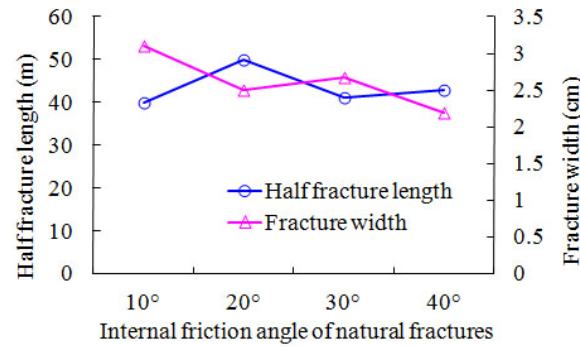
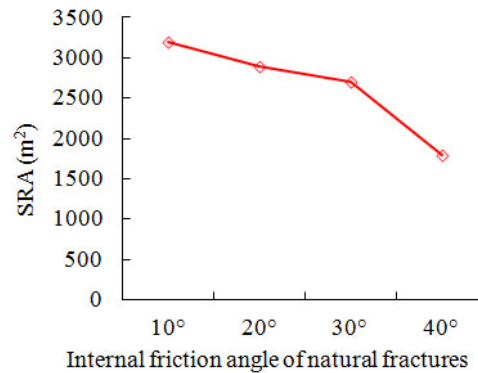


Figure 21 The influence of internal friction angle on hydraulic fracture geometry (see online version for colours)**Figure 22** The influence of internal friction angle of natural fractures on the SRA (see online version for colours)

4.4 The effect of cohesive strength of natural fractures

Simulation results at the injection time of 20 minutes with different cohesive strength of natural fractures of 2, 5, 8 and 11 MPa are shown in Figure 23. With the increase of cohesive strength, the hydraulic fracture length increases while the fracture width decreases. It is getting more and more difficult to generate shear fractures as the cohesive strength of natural fractures becomes larger. Figure 24 demonstrates that when the cohesive strength increases beyond 5 MPa, the SRA of natural fractures decreases rapidly. At the cohesive strength of 11 MPa, the SRA reduces to zero, i.e. there is no shear failure occurring in the natural fracture system. Thus, high cohesive strength of natural fractures inhibits shear fracture emergence. Although fracturing fluid enables constant propagation of hydraulic fracture, it's not enough to cause shear failure of natural fractures.

Figure 23 The influence of cohesive strength of natural fractures on hydraulic fracture geometry (see online version for colours)

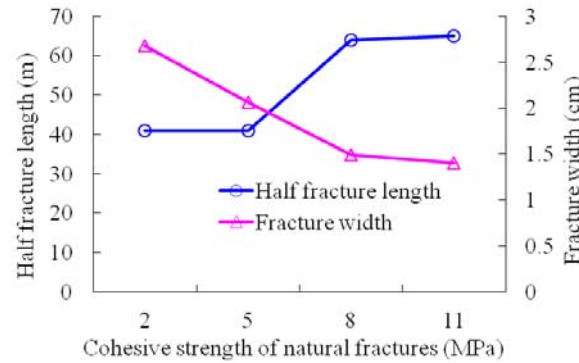
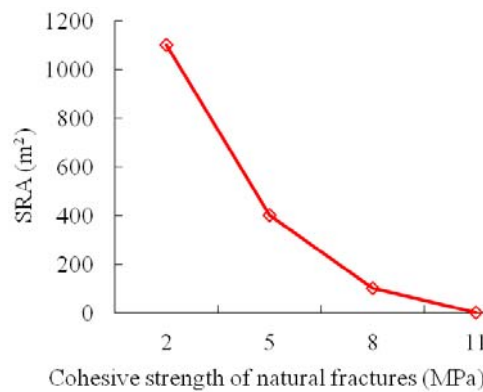


Figure 24 The influence of cohesive strength of natural fractures on the SRA (see online version for colours)



4.5 The effect of Young's modulus and Poisson's ratio

4.5.1 The effect of Young's modulus

Simulation results at the injection time of 50 minutes with Young's modulus of 20, 30, 40, and 50 GPa, are shown in Figure 25. The higher the Young's modulus, the more complicated the fracture networks around the wellbore, and the more shear failure of natural fractures attained. Figure 26 and Figure 27 present that, the larger the Young's modulus, the more obvious the shear failure of natural fractures and the less dominant role the hydraulic fracture plays. When Young's modulus is relative small, fracture width decreases a little while fracture length slowly increases. When the Young's modulus surpasses 30 GPa, the shear failure of natural fractures dominates, accompanied by a decrease in hydraulic fracture length and an increase in fracture width.

Figure 25 Influence of Young's modulus on SRA of natural fractures, (a) Young's modulus is 20 GPa (b) Young's modulus is 30 GPa (c) Young's modulus is 40 GPa (d) Young's modulus is 50 GPa (see online version for colours)

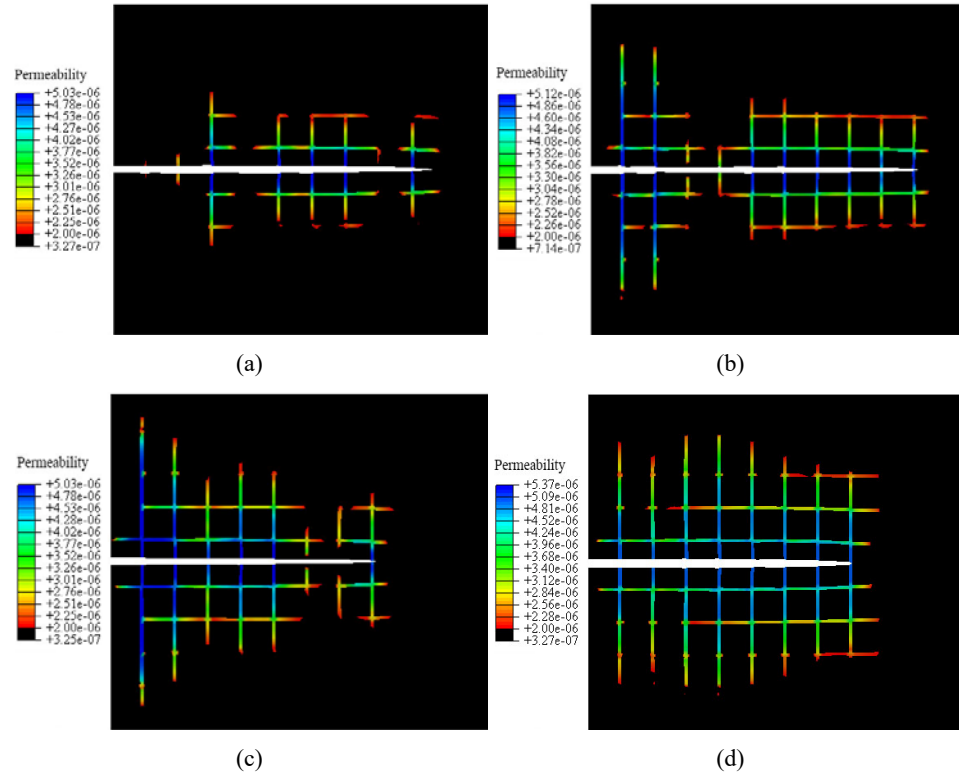


Figure 26 The influence of shale Young's modulus on hydraulic fracture geometry (see online version for colours)

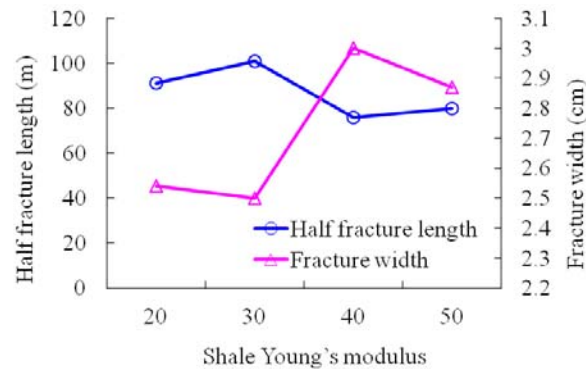
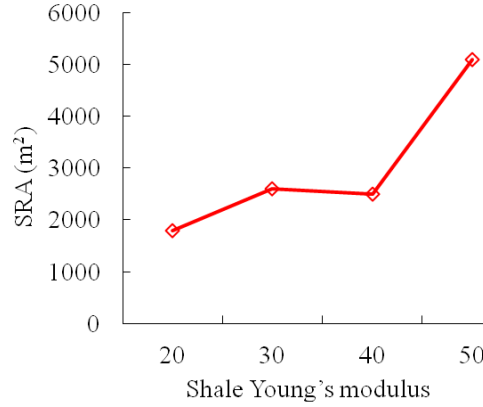


Figure 27 The influence of shale young's modulus on SRA (see online version for colours)

4.5.2 The effect of Poisson's ratio

Simulation results at the injection time of 20 minutes with different Poisson's ratio of 0.1, 0.15, 0.2, and 0.25, are shown in Figure 28. High Poisson's ratio inhibits the growth of shear fractures, in that fewer shear fractures are achieved as the Poisson's ratio goes higher. This conforms to the brittleness index equation of Poisson's ratio, which implies easier shear failure with smaller Poisson's ratio. As is obvious in Figures 29–30, with increasing Poisson's ratio, the hydraulic fracture length increases, meanwhile the fracture width decreases. High Poisson's ratio is in favour of long and narrow fractures, such that the hydraulic fracture propagation plays a dominant role.

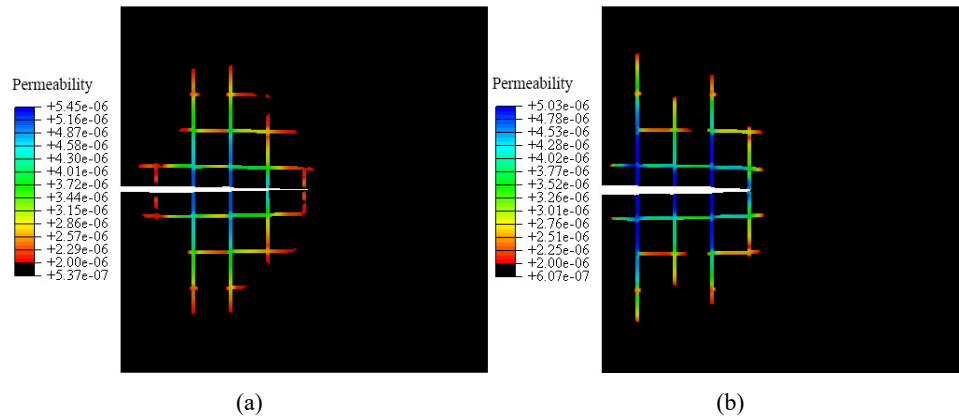
Figure 28 Influence of Poisson's ratio on SRA of natural fractures, (a) Poisson's ratio is 0.1 (b) Poisson's ratio is 0.15 (c) Poisson's ratio is 0.2 (d) Poisson's ratio is 0.25 (see online version for colours)

Figure 28 Influence of Poisson's ratio on SRA of natural fractures, (a) Poisson's ratio is 0.1 (b) Poisson's ratio is 0.15 (c) Poisson's ratio is 0.2 (d) Poisson's ratio is 0.25 (continued) (see online version for colours)

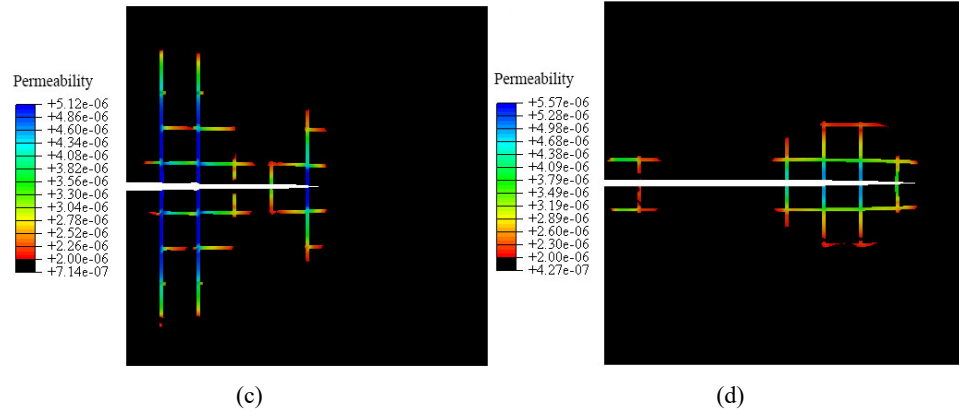


Figure 29 The influence of shale Poisson's ratio on hydraulic fracture geometry (see online version for colours)

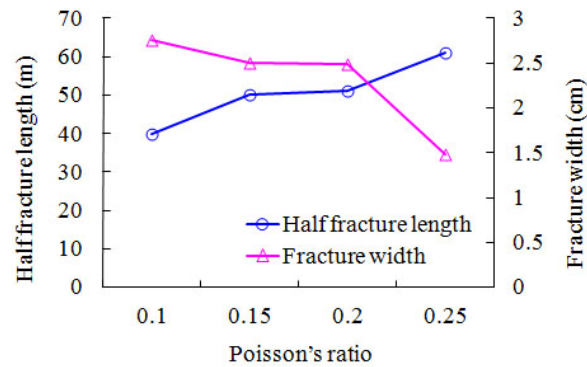
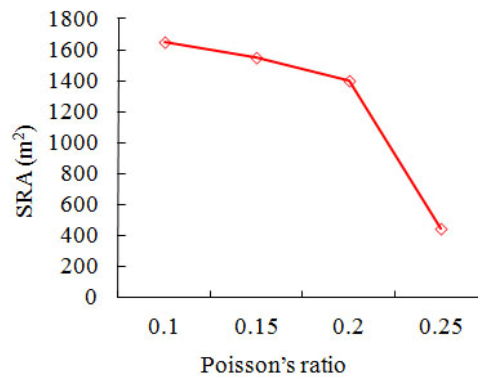


Figure 30 The influence of shale Poisson's ratio on SRA (see online version for colours)



The brittleness indexes of Barnett shale can be calculated from (Rickman et al., 2008; Buller et al., 2010):

$$E_{Brit} = (E - 10) / (80 - 10) \cdot 100 \quad (35)$$

$$\mu_{Brit} = (0.4 - \mu) / (0.4 - 0.1) \cdot 100 \quad (36)$$

$$B_{Brit} = 0.5E_{Brit} + 0.5\mu_{Brit} \quad (37)$$

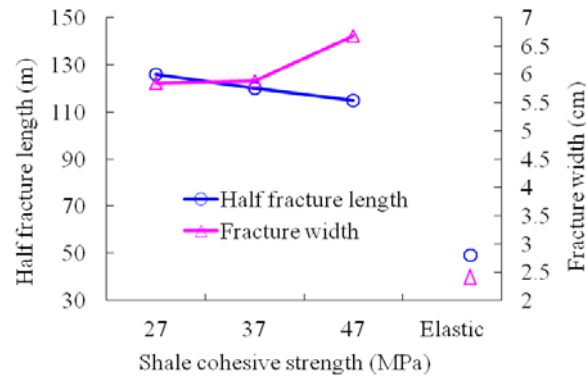
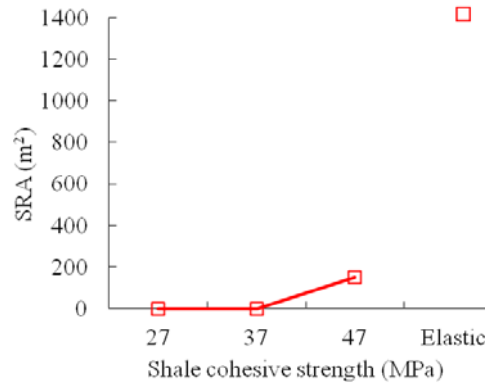
where E_{Brit} is the brittleness index caused by Young's modulus; μ_{Brit} is the brittleness index caused by Poisson's ratio; B_{Brit} is the brittleness index of shale gas reservoir. From the above equation, the higher the Young's modulus, the greater the formation brittleness, and the more easily fracture networks can be generated, verifying the numerical results herein. Jin et al. (2014) recently presented a parameter B_{19} obtained by density and sonic logging, which also indicates that formation with higher Young's modulus and lower Poisson's ratio has higher brittleness.

$$B_{19} = \frac{E_n + v_n}{2} \quad (38)$$

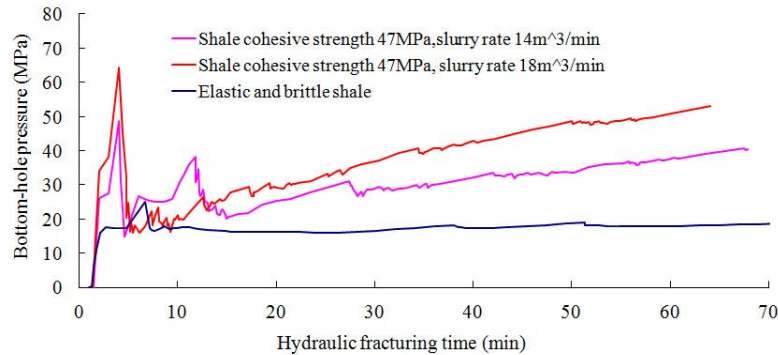
Therefore, it can be drawn that the numerical simulation method in this paper can be used to simulate fracture initiation and propagation during hydraulic fracturing operation in shale gas reservoirs.

4.6 The effect of cohesive strength of shale matrix

To study the influence of shale matrix plasticity on the propagation of natural fracture networks, three sets of shale matrix with the same internal friction angle of 30° and cohesive strength of 47, 37 and 27 MPa are selected for simulations under the same injection rate. As shown in Figures 31–32, when the cohesive strength is less than 37 MPa, shear failure does not happen, so the hydraulic fracture length and fracture width basically do not change. When cohesive strength reaches 47 MPa, shear failure occurs, along with the increase of the fracture width and decrease of the fracture length; yet the SRA of natural fractures is only 150 m^2 . As the shale matrix cohesive strength increases beyond 47 MPa, hydraulic fracture propagation is inhibited due to the shear failure of natural fractures. Since the shale matrix is more brittle and elastic, hydraulic fracture length and width are less than that with high plasticity; nevertheless its SRA is nearly ten times of that in plastic shale matrix. Hence, it is difficult to create shear failure fractures in plastic shale, which explains why the brittleness of shale matrix is a key factor for getting larger SRV.

Figure 31 The influence of shale cohesive strength on hydraulic fracture geometry (see online version for colours)**Figure 32** The influence of shale cohesive strength on SRA (see online version for colours)

As shown in Figure 33, both hydraulic fracturing initiation and propagation pressure for plastic shale are much higher than those of the brittle and elastic shale. The larger the injection rate, the higher the hydraulic fracturing initiation pressure and propagation pressure of the plastic shale, and thus the longer and wider fracture are generated. In field application, increase of hydraulic fracture initiation pressure is related to shale matrix plasticity and shale matrix hydration expansion (El-Fayoumi et al., 2011). High viscosity particles and hydration expansion inhibitor help decrease the fracturing fluid loss, therefore increasing the fracture width. However, for their poor flowability, higher injection pressure is needed. Plastic shale is conducive to generate planar bi-wing fractures, consequently the hydraulic fracture is difficult to initiate and propagate. Even a large number of natural fractures exist; they cannot be connected with ease. Again, this validates that the brittleness of shale gas reservoir is a key factor for SRV. For instance, the Western Canadian Sedimentary Basin (WCSB) shale, similar to a sponge or ooze, has strong extensibility and plasticity. As a consequence, bi-wing fractures can easily arise, but can hardly propagate, rendering it difficult for stimulation treatment (Buller et al., 2010).

Figure 33 Hydraulic fracture curves of plastic shale (see online version for colours)

5 Conclusions

- 1 A dynamic FSD model for hydraulic fracture and pre-existing natural fracture system is proposed and applied for the simulation of hydraulic fracturing in Q1 shale gas well in Sichuan Basin. The simulation results of fracture initiation pressure and propagation pressure are consistent with the field data, indicating that this model is applicable for hydraulic fracturing in shale gas reservoirs.
- 2 With the same fluid injection rate, narrower natural fracture spacing leads to smaller SRA. Thus to obtain the same SRA, larger injection rate is required for narrowly spaced natural fractures. Under the same minimum horizontal stress, the SRA and micro-seismic events of natural fractures increase as the maximum horizontal stress increases. The internal friction angle and cohesive strength of natural fractures have a remarkable influence on the SRA. Smaller internal friction angle and cohesive strength result in larger SRA and more near-wellbore fractures. It's much easier to obtain large SRA in highly brittle shale with higher Young's modulus and lower Poison's ratio. Although plastic shale favours planar bi-wing fractures, they are difficult to initiate and propagate.

Acknowledgments

This work was supported by the Major Program of the National Natural Science Foundation of China (51490653), the Research Foundation of Sichuan Province under Grant No. 2014HH0004, the PetroChina Innovation Foundation (2014D-5006-0213) and SWPU academic fund.

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