## PAPER • OPEN ACCESS

# Impact of Mode I and Mode II Fractures on Fracture-Gas Permeability in Shale: An Experimental Study

To cite this article: Yunhu Lu et al 2020 IOP Conf. Ser.: Earth Environ. Sci. 570 032010

View the article online for updates and enhancements.

## You may also like

- Engineering geological characteristics and the hydraulic fracture propagation mechanism of the sand-shale interbedded formation in the Xu5 reservoir Cong Lu, Mei Li, Jian-Chun Guo et al.
- Enhanced dual-band absorption of graphene mediated by an aluminum metastructure Ghulam Abbas Khan, Yonghua Lu and Pei Wang
- <u>Mode transition of the cylindrical Hall</u> <u>thruster with the near-anode cusp</u> <u>magnetic field</u> Yuanyuan Gao, Weizong Wang, Yifei Li et al.





DISCOVER how sustainability intersects with electrochemistry & solid state science research



This content was downloaded from IP address 3.147.56.18 on 14/05/2024 at 17:48

## **Impact of Mode I and Mode II Fractures on Fracture-Gas** Permeability in Shale: An Experimental Study

Yunhu Lu<sup>1,2,3,\*</sup>, Guanglei Chen<sup>1,2</sup>, Shuai Yang<sup>1,2</sup>, Yan Jin<sup>1,2</sup>, Ji Li<sup>1,2</sup>, and Quan Xie<sup>3</sup>

<sup>1</sup> State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum (Beijing), Beijing, 102249, China

<sup>2</sup> College of Petroleum Engineering, China University of Petroleum (Beijing), Beijing, 102249, China

<sup>3</sup> Department of Petroleum Engineering, Curtin University, 26 Dick Perry Avenue, 6151 Kensington, Western Australia, Australia

\*Corresponding author: Luyh@cup.edu.cn

Abstract: The natural-fracture network and a large part of hydraulic fractures are poorly supported, and the conductivity of the natural-fracture network is highly sensitive to stress and strain during the production stage. In this work, we aimed to understand the impact of mode I (tensile) and mode II (shear) fractures on fracture-gas permeability as a function of effective stress in Long Ma Xi shale in the Dragon Horse Creek Group in Western China. Experimental results showed that the two-mode fracture tortuosity and width of shale were opposite those of sandstone. Our results implied that in Long Ma Xi shale, mode I fractures likely contributed significantly to early-stage high well productivity, with low effective stress, and mode II fractures may contribute to well productivity after the initial stage of gas production, with relatively high effective stress.

### 1. Introduction

Oil and gas exploitation from shale and other tight rocks has become a hotspot topic in the field (Wang et al. 2016). However, matrix permeability is extremely low in these types of rocks, which are highly unsuitable for oil and gas exploitation (Heller et al. 2014). A typical solution is to create manmade fractures through hydraulic fracturing, which produces additional seepage channels, thereby achieving high permeability. Thus, the permeability of fractures is a critical issue in the utilization of hydraulic fracturing (Bruno et al. 2017). Fracture is not a bulk material, and regarding fracture permeability as a property is unlikely, because fracture permeability is influenced by various factors, such as external stresses (Chen et al. 2015). However, if boundary conditions are identical, then fracture permeability can be considered more or less constant in a material.

Current research on fracture permeability is concerned about only single fractures and ignores fracture modes (Weng et al. 2011). However, the fracture mode represents how a fracture is created and will fundamentally influence flow characteristics, even for the same materials. For example, in Berea sandstone, mode I fractures, as opening fractures created by tensile stresses, generally have smooth fracture surfaces because they develop from intragranular microcracks (Benzeggagh et al. 1996). However, mode II fractures, as sliding fractures created by shear stresses, have rough crack surfaces, because their crack surface consists of fractured or crushed grains (Labuz et al. 2006). Thus,

Content from this work may be used under the terms of the Creative Commons Attribution 3.0 licence. Any further distribution of this work must maintain attribution to the author(s) and the title of the work, journal citation and DOI. Published under licence by IOP Publishing Ltd 1

even under identical conditions, the flow characteristics of the two types of fractures will differ considerably.

Theoretically, hydraulic fracturing produces mode I fractures. However, as a consequence of complex in-situ conditions, the complex fracture network involves mode II fractures (Zhang et al. 2017). Thus, evaluating the flow characteristics of the two types of fractures under the same conditions is essential. Particularly, as a typical tight rock, shale can have completely different fracture flow characteristics compared with sandstone.

Therefore, in this study, two types of fractures, that is, mode I and mode II fractures, are generated in shale specimens. After microanalysis of the generated fractures, permeability and stress-sensitivity experiments are performed, and the results are compared in detail to understand the differences. The experimental results can also help produce the preferred fracture type in shale during hydraulic fracturing.

2. Testing material and specimen preparation

The specimens used in the experiment were obtained from shale at a depth of 2321.68 m and 2324.35 m from the Longshixi formation of the Shiheliu formation in the YS-B well in Yixian City, Sichuan Province, China. The analysis results of the mineral composition of the rock specimens are shown in Table 1.

		Table 1. Min	eral compos	ition of rock sp	becimens	
Sampling	Mineral composition (%)					
depth (m)	Quartz	Feldspar	Calcite	Dolomite	Pyrite	Clay
2321.68	31.0	11.4	12.9	5.1	1.2	38.4
2324.35	31.7	5.5	8.3	5.9	3.6	45.0

For the coring of the rock specimens, we took the rock specimens obtained at a depth of 2506.85 m from the YS-A well in Linjing as an example. Based on scanning electron micrographs (SEMs), a twodimensional structure image of the mesomorphology of the vertically stratified core shale specimens was obtained under the coherent backscattering probe mode. In addition, based on the grayscale threshold (Bai et al. 2013), we used the Avizo Fire image analysis software to binarize the grayscale image. Furthermore, the grayscale similarity of the mineral particles and the different particle size distribution maps corresponding to the grayscale images was obtained (Figure 1).



Figure 1. Mesostructure characterization of shale isotropic surface

In the vertically stratified core shale specimens, the mineral grains of different particle sizes were uniformly dispersed without obvious orientation. Therefore, we believed that the core was obtained from the vertical bedding plane direction. At the microscopic scale, the specimens were isotropic.

Based on the SEM observations, the shale specimens in the parallel layer demonstrated obvious orientation characteristics at the microscopic scale, and the mineral grains were arranged parallel to the bedding plane, as shown in Figure 2 and Figure 3.



Figure 2. Bedding plane A



Figure 3. Bedding plane B

At the same time, the nanoscale diagenetic fissures were relatively developed and regularly distributed in parallel layers, with a large opening degree, and the fracture surface was curved and branched, as shown in Figure 4 and Figure 5. Several microcracks were filled with organic matter or asphaltenes, as shown in Figure 5.



Figure 4. Open nanoscale microcracks



Figure 5. Filled nanoscale microcracks

In summary, at the microscopic scale, the microstructure of the shale rock specimens exhibited obvious transverse isotropic characteristics. Therefore, this study suggested that the mechanical properties of the shale rock specimens in the direction parallel to the bedding plane were approximately identical. However, the mechanical properties in the normal direction differed considerably. According to the standard of the engineering rock mass test method (GB/T 50266-2013), the layered surface and its method were identified, and a standard specimen of  $\varphi 25 \times 50$  mm was prepared.

Both types of cracks were prepared using the RTR-1500 triaxial rock mechanics experimental platform manufactured by GCTS USA (Figure 6). The equipment can provide a maximum load confining pressure of 140 MPa, a maximum pore pressure of 140 MPa, a maximum axial static pressure of 1500 KN, and a maximum axial dynamic pressure of 1000 KN. The high loading capacity ensured the simulation accuracy of the formation temperature and the pressure conditions during the experiment.



Figure 6. GCTS RTR-1500 triaxial rock mechanics experimental platform

The shear fracture of the specimens was produced by a triaxial rock shear test. First, the test piece and axial deformation gauge were installed according to the requirements of the RTR-1500 platform. The test piece was oilproof. Next, a certain degree of lateral pressure was exerted and kept constant during the test. Axial pressure was applied simultaneously at a loading speed of 0.5 MPa per second, and the axial load and axial deformation of the test piece were recorded until the test piece broke and the shear fracture was successfully produced. The angle between the cracked surface of the specimen shear fracture and the direction of the bedding was approximately 40° (Figure 7).

Preparation of the tensile fracture of the specimens was conducted through a small hydraulic fracturing experiment. First, the selected portion of the specimens was drilled at a predetermined azimuth and inclination. Next, the upper head of the RTR-1500 platform stress-loading module and specimens were fastened with epoxy resin. The pressurizing section was filled with water and pressurized, and pressure increased stably according to the estimated pressure. When the rock mass broke, the pressure suddenly dropped, and the burst pressure was read when the flow rate rose sharply. When the pump was turned off, the instantaneous closing pressure value was read when the pressure dropped and stabilized, and the tensile fracture was produced successfully (Figure 8).

A simple sketch of the two types of fractures is shown in Figure 7 and Figure 8. Given the different preparation method of the two fracture specimens, distinguishing between them after the fracturing experiment was easy.



Figure 7. Shear fracture

Figure 8. Tensile fracture

## 3. Microanalysis of mode I and mode II fractures

In current shale oil and gas production, fractures are the main leakage channels of drilling fluid. Thus, fracture morphology characterization is highly significant in the study of hydraulic fracturing (Gregory et al. 2011). This study mainly describes the tortuosity and fracture width of shale fractures.

For the prepared fracture specimens, we use a Quanta 200F field emissions scanning electron microscope to obtain their microscopic morphology (Figure 9).



Figure 9. Quanta 200F field emissions scanning electron microscope

To calculate the width of the fractures, we also use the Quanta 200F field emissions scanning electron microscope to calibrate the initial crack width, as shown in Figure 10.



Figure 10. Initial slit width calibration of fracture

When the calibration is completed, we utilize a microstress loading device (Figure 11) to determine the deformation of the specimens perpendicular to the fracture surface under different confining pressures.



Figure 11. Microstress loading device

The SEMs of the two types of fractures obtained by the Quanta 200F field emissions scanning electron microscope during loading are shown in Figure 12 and Figure 13.



Figure 12. SEM diagram of shear fracture



Figure 13. SEM diagram of tensile fracture

Figure 11 and Figure 12 show that the difference in the microstructure of the two types of fractures is obvious. Given that the surface roughness of the two types of fractures differs, the application of a simple plate model will generate numerous errors in the examination of the seepage characteristics of fractures (Chandler et al. 2016).

To illustrate the difference, the concept of tortuosity was introduced. Rose and Burce presented the concept of tortuosity to reflect the tortuosity of fracture surfaces (Rose et al. 1949), which was quickly

popularized and applied in subsequent studies. Meanwhile, no uniform standard for calculating tortuosity existed (Tsang et al. 1984). With the development of the research, experts and scholars became increasingly willing to adopt  $\tau$  as tortuosity; thus, this study also adopts  $\tau$  as tortuosity.

Tortuosity reflects the degree of twists and turns of a fracture, and the calculation formula is shown in Equation 1.

$$\tau = \frac{\text{actual path}}{\text{apparent path}}.$$
 (1)

We use the yardstick method from fractal geometry (Falconer et al. 2004) to measure the two types of fractures, and the measurement method is shown in Figure 14.



Figure 14. Code rule method for measuring tortuosity

The experimentally measured fracture tortuosity classification is shown in Figure 15. The shear fracture curvature of the shale specimens is between 1.48 and 1.63, and the tensile fracture curvature is between 1.27 and 1.35. In general, the shear fracture of the shale specimen curvature is greater than the tensile fracture. However, according to previous research results (Labuz et al. 2006), for traditional sandstone, the tortuosity of the tensile fracture is greater than that of the shear fracture. The results of the shale fracture tortuosity obtained from the experiment are exactly the opposite of those of traditional sandstone.



Figure 15. Tortuosity of fracture

When we determine that the tortuosity of the sample is opposite that of sandstone, we measure the fracture width of the specimens. As mentioned previously, the surface roughness of the two types of fractures differs, and the width ratio of tensile fractures is generally uniform. Thus, the width of the

two types of fractures cannot be directly compared. This study employs the following method for comparison.

For fracture width, the fracture width variation formula is shown in Equation 2.

width variation of fracture = total deformation - matrix deformation. (2) The formula for the deformation amount of the matrix is shown in Equation 3.

matrix deformation = 
$$\frac{\text{Stress}}{\text{Elastic Modulus}} \times \text{Length of specimen loading direction.}$$
 (3)

With these data, fracture width variation under different stress conditions can be calculated, and the calculation method is shown in Figure 16.



Figure 16. Calculation method for equivalent fracture width

After the calculation, we plot the fracture width data under different stresses calculated by the experimental measurements in Figure 17. The fracture width of the shale specimens decreases as confining pressure increases, the slit width of the shear fracture is generally larger than that of the tensile fracture, and the stress sensitivity of the shear fracture is lower than that of the tensile fracture.



Figure 17. Variation of fracture width under different stresses

### 4. Permeability of mode I and mode II fractures

To examine the mechanical properties of the two types of fractures, avoiding permeability, which is also the most intuitive comparison between the two fractures, is impossible. In this experiment, we utilize a pulse decay permeameter to test permeability. The instrument and experimental principle are shown in Figure 18.



Figure 18. Pulse attenuation permeameter and schematic diagram of experimental principle

Owing to poor efficiency and the long duration and low accuracy of dense rocks with low permeability, we use a high-pressure pulse transient method (Brace et al. 1968). That is, under certain stress conditions (axial pressure and confining pressure settings), the pore pressure at one end of the specimen is fixed, and the pore pressure at the other end is lowered, thereby producing an initial osmotic pressure difference at both ends of the specimen. As fluid seeps into the fracture of the rock specimen, the pore pressure difference decreases continuously, and the decay process of the pore

pressure difference within a certain period of time is measured. The permeability of the specimen under this stress state can be calculated according to Equation 4.

$$K = \mu \beta V \left( \frac{\ln \left( \frac{\Delta P_1}{\Delta P f} \right)}{2\Delta t \frac{As}{Ls}} \right), \tag{4}$$

where

- $\mu$  represents fluid kinematic viscosity; water is used as the fluid, and the viscosity coefficient of water at 20°C is  $1.005 \times 10^{-3}$  Pa·s
- $\beta$  is the volumetric compressibility factor of the fluid •
- $\Delta Pi$  denotes the initial pore pressure difference (Pa) •
- $\Delta Pf$  is the final pore pressure difference (Pa) •
- t signifies the test time (s) •
- As represents the original cross-sectional area of the specimen  $(m^2)$
- Ls is the original length of the specimen (m) •

This method considerably reduces the test time and improves the test accuracy of the permeability of the hypotonic specimens.

The permeability of the eight specimens is calculated (permeability under a confining pressure of 5 MPa, 10 MPa, 15 MPa, and 20 MPa) according to Equation 4, and the results are shown in Table 2.

<b>Table 2.</b> Permeability of eight specimens at 5 MPa, 10 MPa, 15 MPa, and 20 MPa				
Pressure/MPa	5 MPa	10 MPa	15 MPa	20 MPa
Permeability/µD				
Shear fracture I	28.5	11.57	6.43	4.29
Shear fracture II	15.02	6.3	3.72	2.43
Shear fracture III	25.1	9.46	5.35	3.38
Shear fracture IV	13.47	5.32	3.19	1.56
Tensile fracture I	58.3	23.9	13.3	10.29
Tensile fracture II	42	18.36	11	8.28
Tensile fracture III	33.8	11.06	4.05	2.08
Tensile fracture IV	28.47	13.75	3.19	1.56

. ... c · 1 . 5 M. 10 M. 15 M. **...** 10010

#### 5. Stress sensitivity of mode I and mode II fractures

Local and international research focuses consistently on the stress sensitivity of fractures (Wang et al. 2014). In an actual shale oil and gas reservoir, the formation pressure is highly complex and a major challenge (Hossain et al. 2008) for long-term fractures caused by fracturing. Fractures with high stress sensitivity can close easily under high ground stress, which can slow or prevent the migration of oil and gas and reduce effective permeability (Wang et al. 2015). We measure the permeability of the two fracture samples, which is far from adequate. Fractures that can exist for long periods are essential in practical engineering. Therefore, stress sensitivity must be considered.

By measuring the permeability data of shear fracture and tensile fracture under different stresses, we obtain the permeability and stress-sensitivity characteristics of the different fractures, as shown in Figure 19 and Figure 20. Although the curve models of the two pictures are similar, they decrease exponentially (Seidle et al. 1992), and the decline of the mode I fracture is evidently higher than that of the mode II fracture. When a confining pressure of 20 MPa is added, the average permeability of the shear fracture specimens is 5  $\mu$ D, but the average permeability of the other types of specimens is 10  $\mu$ D. The permeability measurement shows that the permeability of the mode I fracture is 1.5–2.0 times the permeability of the mode II fracture at effective stress within the range of 5 MPa to 12 MPa.

The results of the two types of fractures are presented in Figure 21 to provide a highly intuitive contrast. When the confining pressure reaches 20 MPa, the permeability of the two tensile fracture specimens is lower than that of some of the shear fracture specimens.

Figure 21 clearly shows that the tensile fracture is more sensitive to stress than the shear fracture. In actual shale oil and gas production, formation stress conditions are extremely complex. Under complex stress conditions, the seepage channels of tensile fractures are tightly closed, thereby resulting in a rapid decline in permeability.



Figure 19. Permeability stress sensitivity of shear fracture



Figure 20. Permeability stress sensitivity of tension fracture



Figure 21. Permeability stress sensitivity of two types of fractures

Owing to the small pore throat of a low-permeability reservoir medium, its permeability is highly sensitive to pressure. The permeability of a medium changes as pressure changes. Advanced well completion engineering (Wan, 2011) can derive the stress-sensitivity coefficient, and the formula is shown in Equation 5.

$$S_s = \frac{1 - \left(\frac{K}{K_0}\right)^{\frac{1}{3}}}{\lg \frac{\sigma}{\sigma_0}},\tag{5}$$

where

- K represents permeability  $(\mu D)$
- $K_0$  denotes the initial permeability( $\mu D$ )
- $\sigma_0$  is the initial effective stress (MPa)
- $\sigma$  is the effective stress (MPa)
- $S_s$  signifies the stress-sensitivity coefficient

In the experimental specimens, pore pressure can be ignored, and the effective stress is equal to the confining pressure. The calculation results of the stress-sensitivity coefficient of the eight specimens according to Equation 5 are shown in Table 3. From the calculation results, we can easily conclude that tensile fractures are more sensitive than shear fractures.

To verify the reliability of this finding, the permeability damage rate equation of formation damage evaluation by flow test published by China in 2010 (SY/T 5358-2010) is used for the calculation and comparison. The results also confirm the reliability of the data in Table 3. The formula is shown in Equation 6, and the results are presented in Table 4.

$$R_i = \frac{K_0 - K_i}{K_0} \times 100\%,$$
(6)

where

- K represents permeability  $(\mu D)$
- $K_0$  is the initial permeability ( $\mu D$ )
- $R_i$  denotes the permeability damage rate

After analysis, some errors may be observed in the calculation results of the tensile fracture I and tensile fracture II. Two possible reasons for this result are described below.

- 1. Specimen preparation problems
- 2. Experimental process problems

However, proving that tensile fractures are more sensitive than shear fractures based on the average results of the calculation is sufficient.

Specimen	Stress-sensitivity coefficient	
Shear fracture I	0.7774	
Shear fracture II	0.7559	
Shear fracture III	0.8096	
Shear fracture IV	0.8513	
Shear fracture average	0.7986	
Tensile fracture I	0.7293	
Tensile fracture II	0.6943	
Tensile fracture III	1.0052	
Tensile fracture IV	1.0301	
Tensile fracture average	0.8647	

**Table 3.** Stress-sensitivity coefficient of eight specimens

	I able 4.   Permeability	ty damage rate of	f eight s	pecimens	
7	•		P	1 . 1 . 1	

Specimen	Permeability damage rate	
Shear fracture I	84.95%	
Shear fracture II	83.82%	
Shear fracture III	86.53%	
Shear fracture IV	88.42%	
Shear fracture average	85.93%	
Tensile fracture I	82.35%	
Tensile fracture II	80.29%	
Tensile fracture III	93.85%	
Tensile fracture IV	94.52%	
Tensile fracture average	87.75%	

#### 6. Conclusion and summary

In the previous sections, we discuss differences in microstructure, permeability, and stress sensitivity between two-mode fractures. According to the rock specimens obtained from the Longmaxi formation, the two-mode fractures exhibit the following characteristics:

- 1. The tortuosity of the mode II fracture is 1.35 times the tortuosity of the mode I fracture and is opposite the tortuosity of fractures in conventional sandstone reservoir rocks.
- 2. The width contrast of the mode II fracture is larger than that of the mode I fracture.
- 3. In terms of the stress sensitivity of the two types of fractures, the mode I fracture is more sensitive than the mode II fracture. When stress changes, the permeability of the mode I fracture changes dramatically.
- 4. In low-stress conditions, the permeability of the mode I fracture is greater than that of the mode II fracture. However, as stress increases, the permeability of several experimental mode II fracture specimens becomes larger than that of the mode I fracture specimens.

With the above characteristics, we can easily infer that in the shale development in the Longmaxi formation, mode I fractures likely contribute significantly to early-stage high well productivity, with low effective stress, whereas mode II fractures may contribute to well productivity after the initial stage of gas production, with relatively high effective stress.

At the same time, our results reveal three new insights.

1. Pressure-dependent natural-fracture permeability in shale is associated with mode I (tensile) and mode II (shear) fractures.

- 2. Mode I fractures are more susceptible to pressure-dependent natural-fracture permeability compared with mode II fractures.
- 3. Mode II fractures demonstrate relatively high surface tortuosity, which can likely account for the maintenance of fracture conductivity at high effective stress levels.

### Reference

- [1] Shuling W, Xishun W, Wei Z. Progress and trend of global exploration and development for shale resources[J]. *China Mining Magazine*, 2016, **25**(2): 7-11.
- [2] Heller R, Vermylen J, Zoback M. Experimental investigation of matrix permeability of gas shalesExperimental Investigation of Matrix Permeability of Gas Shales[J]. AAPG bulletin, 2014, 98(5): 975-995.
- [3] Figueiredo B, Tsang C F, Rutqvist J, et al. Study of hydraulic fracturing processes in shale formations with complex geological settings[J]. *Journal of Petroleum Science and Engineering*, 2017, **152**: 361-374.
- [4] Chen D, Pan Z, Ye Z. Dependence of gas shale fracture permeability on effective stress and reservoir pressure: model match and insights[J]. *Fuel*, 2015, **139**: 383-392.
- [5] Weng X, Kresse O, Cohen C E, et al. Modeling of hydraulic fracture network propagation in a naturally fractured formation[C]//SPE Hydraulic Fracturing Technology Conference. Society of Petroleum Engineers, 2011.
- [6] Benzeggagh M L, Kenane M. Measurement of mixed-mode delamination fracture toughness of unidirectional glass/epoxy composites with mixed-mode bending apparatus[J]. Composites science and technology, 1996, 56(4): 439-449.
- [7] Labuz J F, Riedel J J, Dai S T. Shear fracture in sandstone under plane-strain compression[J]. *Engineering fracture mechanics*, 2006, **73**(6): 820-828.
- [8] Zhang Z, Li X, He J, et al. Numerical study on the propagation of tensile and shear fracture network in naturally fractured shale reservoirs[J]. *Journal of Natural Gas Science and Engineering*, 2017, **37**: 1-14.
- [9] Bai B, Elgmati M, Zhang H, et al. Rock characterization of Fayetteville shale gas plays[J]. *Fuel*, 2013, **105**: 645-652.
- [10] Gregory K B, Vidic R D, Dzombak D A. Water management challenges associated with the production of shale gas by hydraulic fracturing[J]. *Elements*, 2011, 7(3): 181-186.
- [11] Chandler M R, Meredith P G, Brantut N, et al. Fracture toughness anisotropy in shale[J]. *Journal of Geophysical Research*: Solid Earth, 2016, **121**(3): 1706-1729.
- [12] Rose W, Bruce W A. Evaluation of capillary character in petroleum reservoir rock[J]. *Journal* of Petroleum Technology, 1949, 1(05): 127-142.
- [13] Tsang Y W. The effect of tortuosity on fluid flow through a single fracture[J]. *Water Resources Research*, 1984, **20**(9): 1209-1215.
- [14] Falconer K. Fractal geometry: mathematical foundations and applications[M]. John Wiley & Sons, 2004.
- [15] Wang H T. Performance of multiple fractured horizontal wells in shale gas reservoirs with consideration of multiple mechanisms[J]. *Journal of Hydrology*, 2014, **510**: 299-312.
- [16] Hossain M M, Rahman M K. Numerical simulation of complex fracture growth during tight reservoir stimulation by hydraulic fracturing[J]. Journal of Petroleum Science and Engineering, 2008, 60(2): 86-104.
- [17] Wang C, Wu Y S, Xiong Y, et al. Geomechanics coupling simulation of fracture closure and its influence on gas production in shale gas reservoirs[C]//SPE reservoir simulation symposium. Society of Petroleum Engineers, 2015.
- [18] Brace W F, Walsh J B, Frangos W T, et al. Permeability of granite under high pressure[J]. *Journal of Geophysical Research*, 1968, **73**(6): 2225-2236.
- [19] Seidle J P, Jeansonne M W, Erickson D J. Application of matchstick geometry to stress dependent permeability in coals[C]//SPE rocky mountain regional meeting. Society of

Petroleum Engineers, 1992.

- [20] Wan Renpu, Advanced well completion engineering[M]. Petroleum Industry Press. 2001.
- [21] Formation damage evaluation by flow test. Petroleum and natural gas industry standard of the people's Republic of China. SY/T 5358-2010.