Fracturing curve and its corresponding gas productivity of coalbed methane wells in the Zhengzhuang block, southern Qinshui Basin, North China

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Abstract
Hydraulic fracturing has been widely used in low permeability coalbed methane reservoirs to enhance gas production. To better evaluate the hydraulic fracturing curve and its effect on gas productivity, geological and engineering data of 265 development coalbed methane wells and 14 appraisal coalbed methane wells in the Zhengzhuang block were investigated. Based on the regional geologic research and statistical analysis, the microseismic monitoring results, in-situ stress parameters, and gas productivity were synthetically evaluated. The results show that hydraulic fracturing curves can be divided into four types (descending type, stable type, wavy type, and ascending type) according to the fracturing pressure and fracture morphology, and the distributions of different type curves have direct relationship with geological structure. The vertical in-situ stress is greater than the closure stress in the Zhengzhuang block, but there is anomaly in the aggregation areas of the wavy and ascending fracturing curves, which is the main reason for the development of multi-directional propagated fractures. The fracture azimuth is consistent with the regional maximum principle in-situ stress direction (NE–NEE direction). Furthermore, the 265 fracturing curves indicate that the coalbed methane wells owned...
descending, and stable-type fracturing curves possibly have better fracturing effect considering the propagation pressure gradient ($F_p$) and instantaneous shut-in pressure ($P_{ISI}$). Two fracturing-productivity patterns are summarized according to 61 continuous production wells with different fracturing type and their plane distribution, which indicates that the fracturing effect of different fracturing curve follows the pattern: descending type $>$ stable type $>$ wavy type $>$ ascending type.

**Keywords**
Coalbed methane, fracturing curve, gas productivity, fracturing effect

**Introduction**
Coalbed methane (CBM) is a kind of high-quality and large reserves unconventional gas resource, development of which can not only reduce methane emission from coal mining and alleviate the greenhouse effect, but also effectively reduce coal mining accidents and obtain economic energy (Karacan et al., 2011). The total CBM reserve in China is estimated to be 30.05 trillion cubic meters (Tcm), and the minable CBM is 12.5 Tcm within coal seam less than 2000 m in depth (Tao et al., 2019), half of which occur in the Qinshui, Ordos, and Junggar coal-bearing basins (Xu et al., 2012).

The production of CBM has a process of gas and water complex flow (Li et al., 2017). First, the coal reservoir pressure should be reduced below the critical desorption pressure by extracting the formation water, then CBM desorbs and diffuses from matrix pores to fractures/cleats with the decrease of concentration and pressure, and finally flows into the wellbore through the fracture system (Pan and Da, 2015; Zou et al., 2018). Normally, high rank coals have particular performance of low porosity, low permeability, low reservoir pressure, and high gas saturation (Cai et al., 2018; Singh et al., 2015; Yao et al., 2019). Therefore, reservoir stimulation is often required for enhancing gas production (Hou et al., 2013). The frequently used stimulation technology is hydraulic fracturing, which is also a widely used method for unconventional reservoirs. Fracturing is to inject the fracturing fluid into the CBM well with a displacement that greatly exceeds the reservoir resistance (Zhang et al., 2016). During this process, proppant is injected to prop-up fracture to improve fluid flow capability and thus increase CBM production (Zhang and Bian, 2015; Wang et al., 2017). Generally, fracturing can be divided into three stages based on the fracturing curves: the rupture stage, the fracture-forming stage, and the pump stop stage (Yu, 2010). The variable fracturing pressure at different stages can be adopted to evaluate fracturing effect (Belyadi et al., 2017).

In-situ stress is the internal stress presenting in the earth crust and mainly controlled by gravity and tectonics (Ju et al., 2018), which is an important factor for fracturing (Bell, 2006; Chen et al., 2018; Talebi et al., 2014). The in-situ stress generally has stressed, anisotropic, and non-uniform component, which control the morphology of hydraulic fractures, ground construction pressure, and proppant crushing and embedding (Tang et al., 2011; Wu et al., 2006). At present, hydraulic fracturing is also a reliable way to detect the in-situ stress state at a known depth. The closure stress and break-down pressure can be assessed by well tests (Zuber et al., 1990). The Poisson’s ratio of coal is high, while the Young’s modulus, compressive strength, and tensile strength are relatively low when compared with conventional
gas reservoirs (e.g. sandstone and limestone) (Singh, 2011). Moreover, the mechanical anisotropy is significant due to the well-developed cleats and fractures in coal (Li et al., 2015), which causes fracturing propagation and fracture morphology in CBM reservoir different from that in conventional reservoirs.

Previous researchers have studied the hydraulic fracture propagation and controlling factors of CBM reservoirs through mathematical simulations (Adachi et al., 2007; Huang et al., 2018; Nordren, 1972; Wang et al., 2017) and experiments (Dehghan et al., 2015; Liu et al., 2018; Zhou et al., 2010). Fracturing initiation and propagation of hydraulic fractures can reflect the fracturing effect. However, due to geological and engineering factors, the on-site fracturing effect of CBM wells is quite different from theoretical and experimental results. Therefore, the fracturing effect based on microseismic monitoring and production data of CBM wells is proposed. In this study, fracturing curves of about 300 CBM wells are carefully analyzed and evaluated, and then the geological distribution of different fracturing curves is distinguished in the Zhengzhuang Block southern Qinshui Basin, North China. Finally, the fracturing effect is comprehensively evaluated with the aspects of fracturing curves, microseismic monitoring results, in-situ stress change, and CBM well productivity. This research should benefit for optimizing fracturing design as CBM reservoir stimulation as well as well spacing in the high rank coals.

**Geological settings**

Zhengzhuang Block is located in the southern Qinshui Basin with the area of approximately 680 km² (Figure 1(a)), which experienced two stages of tectonic movement in the late Yanshanian and Himalayan periods (Su et al., 2005). The current geological structure is down sloping from the SE to the NW. The normal faults with NNÉ, NE, and EW strike mainly concentrate in the east and southeast areas. The Taiyuan Formation of the Upper Carboniferous and the Shanxi Formation of the Lower Permian were typical coal-bearing clastic sediments of stable marine-terrigenous facies of the Late Paleozoic in north China. The Shanxi Formation in the Zhengzhuang Block was developed in fluvial delta sedimentary environment, which consists of mudstone, sandstone, siltstone, and coal seams (Cai et al., 2011). The No. 3 coal seam of the Lower Permian Shanxi Formation is the target seam, which distributes stably and continuously in the horizontal direction. It has thickness of 2.4–7.35 m with an average of 5.61 m. Coal core appraisal, hydraulic fracturing, and production test of over 100 CBM appraisal wells have been finished.

In this work, development unit A of the Zhengzhuang Block in Figure 1(b) is the target area. The burial depth of No. 3 coal seam gradually deepens from the center to the periphery, which ranges from 1136.5 to 473.8 m with an average of 720.48 m. The thickness of coal seam is 4–6.25 m, with an average of 5.39 m. The coal seam in the NW and SE directions is thick, and the tectonic coal is mainly concentrated in the SE zone. The gas content in coal is 1.51–31.44 m³/t, with an average of 19.89 m³/t. The coal seam porosity ranges from 3.03 to 10.74%, with an average of 5.44%. Based on the elevation and geological structure, unit A is divided into slope zone, uplift zone, and fault zone from the NW to the SE (Figure 1(c)). Generally, strongly deformed coal is located in the uplift zone and the fault zone, where porosity is relatively larger than the slope zone, same as the permeability. The coal seam in the uplift zone locates along the anticline and has a shallow burial depth, which possibly caused the gas content to be relatively low in the NW area. The geological factors should
have significant impacts for the fracturing effect of CBM reservoirs and thus for CBM production.

**Materials and methodology**

**Statistics of CBM wells**

There are 279 CBM wells including 14 appraisal wells and 265 development wells in the Zhengzhuang Block. The appraisal wells distribute throughout the research area, while the development wells are concentrated in the unit A. In this work, the fracture monitoring data of appraisal wells and fracturing curves, fracturing engineering parameters, and production profiles of 265 CBM development wells were collected. Moreover, the 14 appraisal wells, having comprehensive well logging and petrophysical data, can be used to evaluate the geological structure and reservoir performance in the Zhengzhuang block. Although 265 CBM development wells were collected, parts of them have gas production interruption during the production process due to the field weather and engineering problems. To ensure the evaluation accuracy, only 61 CBM wells with continuous production curves chosen from the 265 development wells were used for production analysis in unit A.

**Stress analysis during fracturing**

In-situ stresses control fracturing design, treatment, and execution during fracturing process (Chen et al., 2018). The fracturing curve indicates the performance of the bottom hole pressure ($P_{BH}$) change during the hydraulic fracturing, which plays a critical role in
monitoring fracturing process and engineering adjustment (Smith and Montgomery, 2015). Figure 2(a) shows the scheme of actual hydraulic fracturing well and pressure test equipment in the Zhengzhuang Block. The typical fracturing curve shown in Figure 2(b) reflects the ideal $P_{BH}$ change. The main fracturing pressures are break-down pressure ($P_B$), propagation pressure ($P_P$), instantaneous shut-in pressure ($P_{ISI}$), closure stress ($P_C$), vertical and horizontal in-situ stress ($\sigma$), and formation pressure ($P_F$). The coal rock may break when the bottom hole pressure is greater than the fracture toughness of coal. $P_B$ is the initial stress that causes the coal rock broken. $P_P$ refers to the pressure inside the fracture that makes the fracture propagate during pumping. $P_{ISI}$ is the bottom hole pressure at the moment of all pumps are closed. $P_C$ is the minimum fluid pressure that keeps the hydraulic fracture open, which can be determined from diagnostic fracture injection test (DFIT) (Belyadi et al., 2017) or multi-cycle hydraulic fracturing (Zuber et al., 1990). $P_C$ is equal to the minimum horizontal in-situ stress but has an opposite direction ($\sigma_{H_{\text{min}}}$) (for vertical hydraulic fracture) and perpendicular to the hydraulic fracture surface (equation (1)) (Haimson and Cornet, 2003; Nolte, 1979). As the stage of pressure fall-off after the pump stop is approximate to that in the DFIT, $P_C$ can be substituted with $P_{ISI}$ approximately in equation (1). $P_B$, $P_P$, and $P_{ISI}$ can be acquired from the fracturing curve and the break-down pressure gradient ($F_B$) and fracture propagation pressure gradient ($F_P$) using equations (2) and (3). In addition, the vertical stress ($\sigma_v$) can be obtained from equation (4) (Hoek and Brown, 1980). The relationship between in-situ stress and fracture curves will be elaborated in “Hydraulic fractures morphology and its relationship with in-situ stress” section.

$$P_C = \sigma_{H_{\text{min}}} \approx P_{ISI}$$

$$F_B = \frac{P_B}{H}$$

$$F_P = \frac{P_P}{H}$$

**Figure 2.** (a) Schematic of typical hydraulic fracturing well and pressure test equipment; (b) illustration of ideal fracturing pressure versus time curve recorded during coal reservoir hydraulic fracturing.
where $P_C$ is the closure stress (MPa), $\sigma_{H\min}$ is the minimum horizontal in-situ stress (MPa), $P_{ISI}$ is the instantaneous shut-in pressure (MPa), $P_B$ is the break-down pressure (MPa), $F_B$ is the break-down pressure gradient (MPa/100 m), $F_P$ is the fracture propagation pressure gradient (MPa/100 m), $\sigma_V$ is the vertical in-situ stress (MPa), and $H$ is coal seam burial depth (m).

After the pump is closed, the residual fracturing fluid in the hydraulic fractures continuously infiltrates into CBM reservoirs and the fractures with proppant begin to close under the formation pressure. The permeability of hydraulic fractures with proppant reflects the effective conductivity of fractures when the pressure in the near wellbore returns to the formation pressure (Li et al., 2012). By calculating the pressure drop speed ($V_p$) from $P_{ISI}$ to $P_F$ after pump stop (equation (5)), the fluid loss of fracturing and the propagation of the hydraulic fractures can be qualitatively determined.

$$V_p = \frac{P_{ISI}}{C0P_F} = \frac{1}{t}$$

where $V_p$ is the pressure drop speed (MPa/h) and $t$ is the testing time (h).

**Hydraulic fracture monitoring**

Fracturing may cause in-situ stress field change and fractures generate as well as microseism happen in the rock formation (Julie and Paul, 2010). By arranging high-sensitivity seismic sensors around the fracturing wells, the microseismic monitoring technology can capture hydraulic fractures in real time from coal seam (Wang et al., 2015). According to the microseismic travel time, the location of the seismic source, namely the location of fracture, can be calibrated (Waldron and Camac, 2016; Zhu et al., 2017). The spatial distribution of the hydraulic fractures can be described accurately by the spatial distribution of the microseism and its projection on the plane in the cylindrical coordinate system. Although fracture monitoring technology cannot accurately measure the fracture width right now, fracture orientation, length, and height can be detected.

A schematic diagram (appraisal well W13) of microseismic monitoring is presented in Figure 3. Six microseismic detectors around the wellbore (Figure 3(a)) can observe and transfer every seismic source data wirelessly, which indicates the hydraulic fracture propagation direction and height. And the color dots in Figure 3(b) show the time sequence of the microseismic occurrence. Moreover, fracture morphology can be further inversed by microseismic signal. Due to the monitoring cost and complex geological conditions, only hydraulic fractures of 14 CBM appraisal wells were monitored, which reflects the hydraulic fracture propagation in the No. 3 coal seam. The fracturing curves and factors controlling hydraulic fractures will be discussed in “Hydraulic fractures morphology and its relationship with in-situ stress” section.

**Results and discussions**

**Fracturing curves**

With the statistics of 279 appraisal and development CBM wells in the Zhengzhuang block, the fracturing curves were divided into descending type, stable type, wavy type, and
ascending type. The descending-type fracturing curve (Figure 4(a)) corresponds to two propagation modes. On one hand, apparent main fractures initiate in coal seam, which rapidly expand and propagate with a stable fracturing fluid loss rate. The bottom hole pressure continues to drop due to the large volume of fluid loss. On the other hand, the hydraulic fractures may communicate with pre-existing natural fractures (Zhang et al., 2016) or propagate into the high permeability, tectonic broken, and low in-situ stress area, which cause the pressure drop quickly. The stable-type fracturing curve (Figure 4(b)) generally has obvious break-down pressure at the initial stage of fracturing. Once the coal breaks, the fracture continues to propagate, and the pressure rapidly drops to a relatively stable value. Then, the fracturing fluid injection and loss volume reach a dynamic balance, which has hardly fracture-making ability and mainly loses in coal seam (Smith and Montgomery, 2015). In general, this type curve shows the smooth fracture expand, low propagation pressure, and relatively simple fracture morphology. The pressure of the wavy-type fracturing curve (Figure 4(c)) is unstable, which means the strong reservoir heterogeneity and well development of cleats and pre-existing natural fractures. The hydraulic fractures expand uncontinuously, forming multi-directional propagated and complex fracture (Wu et al., 2018). This type curve owns relatively high and continuously changed pressure, which indicates the complex and random hydraulic fracture morphology. The ascending-type fracturing curve (Figure 4(d)) shows that the pressure continuously increases, and the breakdown pressure is amphibolous. This kind of curve possibly indicates that the strong coal strength, high in-situ stress, coal fines, and proppant blocking and the multi-directional propagated fractures during the fracturing process (Liu et al., 2018; Wang et al., 2017).

According to the characteristics of the four type fracturing curves, three typical patterns (narrow and tabular, dendritic, and parallel multifractures) of multi-directional propagated fractures (Figure 5(a) to (c)) were detected. Compared to the normal propagation fracture (Figure 5(d)), individual fractures propagate tortuously near the wellbore and interact with each other. This will lead to abnormal bottom hole pressure or sand plugging during

Figure 3. (a) Layout diagram of microseismic monitoring stations; (b) 3D view of microseismic events (location of appraisal well W13 see Figure 1(b)).
Figure 4. Four typical hydraulic fracturing curves: (a) descending type; (b) stable type; (c) wavy type; (d) ascending type.

Figure 5. Schematic of three kinds of multi-directional propagation fractures and a normal propagation fracture: (a) narrow and tabular multifractures; (b) dendritic multifractures; (c) parallel multifractures; (d) normal propagation fracture.
fracturing, resulting in multi-directional propagated short fractures with narrow fracture width and low conductivity. These multi-directional propagated fractures usually occur in wavy and ascending-type fracturing curve, which directly restrict the fracture propagation.

The areal distribution of the fracturing curve types of the 265 development wells in the development unit A is shown in Figure 6, which indicates that the four types of fracturing curves aggregate locally in unit A. The stable fracturing curves are mainly distributed in the NW slope zone (Figure 6(a)), which indicates the stable coal seam and relatively simple tectonics and in-situ stresses; the descending curves are concentrated in the middle uplift zone, which has moderate deformation that is conducive to the hydraulic fractures propagation (Figure 6(a)); the wavy and ascending-type curves are mostly distributed in the coal seam uplift zone and fault zone (Figure 6(b)), which correlate with the reservoir heterogeneity, complex in-situ stress, and well-developed pre-existing natural fractures. The statistics of fracturing curves in the three geological structures indicate that from the NW slope zone to the middle uplift zone then to the SE fault zone, the proportion of the stable and descending-type curves reflects the well-propagated fractures and gradually decreases from 88 to 68% and then to 46%. On the contrary, the ratio of the wavy and ascending curves shows the weak-propagated fractures rapidly increase from 12 to 32% and then to 54% (Figure 7).

**Hydraulic fractures morphology and its relationship with in-situ stress**

*Microseismic monitoring results.* The main fracture morphology of 14 appraisal wells in the Zhengzhuang block was obtained by microseismic monitoring (Table 1), which show that all main hydraulic fractures are vertical in the No. 3 coal seam. Fracture length ranges from 152 to 221.3 m, and the two fracture wings are basically symmetrical but not equal in length, ranging from 61.1 to 115.1 m. The fracture height is 4.39–10.7 m, which shows a negative correlation with fracture length. The fracture azimuth is between NE 49.6° and NE 85.3°. Four appraisal wells with different fracturing curve types show that the fracture spatial morphology is directly related to the fracturing curve type as described in “Fracturing
Figure 7. Statistics of four fracturing curve types in different tectonic region in development unit A.

Table 1. Microseismic monitoring results of hydraulic fractures of 14 appraisal wells in the Zhengzhuang block.

| No. | Wells | Statistical azimuth | Fracture length (m) | Fracture length of east/west wing (m) | Fracture height (m) | Fracture pattern |
|-----|-------|---------------------|---------------------|---------------------------------------|--------------------|-----------------|
| 1   | W1    | NE56.2°             | 152.00              | 61.10/90.90                           | 6.70               | Vertical        |
| 2   | W2    | NE52.8°             | 218.70              | 109.30/109.40                         | 8.00               | Vertical        |
| 3   | W3    | NE81.8°             | 170.70              | 78.50/92.20                           | 6.60               | Vertical        |
| 4   | W4    | NE70.0°             | 197.71              | 92.45/105.26                          | 6.56               | Vertical        |
| 5   | W5    | NE56.1°             | 187.80              | 98.60/89.20                           | 7.42               | Vertical        |
| 6   | W6    | NE75.3°             | /                   | /                                     | /                  | Vertical        |
| 7   | W7    | NE64.7°             | 160.00              | 76.50/83.50                           | 10.70              | Vertical        |
| 8   | W8    | NE49.6°             | 216.74              | 110.48/106.26                         | 6.83               | Vertical        |
| 9   | W9    | NE81.5°             | 192.00              | 94.85/97.15                           | 7.46               | Vertical        |
| 10  | W10   | NE64.5°             | 195.05              | 80.52/114.53                          | 7.45               | Vertical        |
| 11  | W11   | NE85.3°             | 218.04              | 108.02/110.02                         | 4.39               | Vertical        |
| 12  | W12   | NE54.5°             | 202.71              | 114.36/88.35                          | 6.50               | Vertical        |
| 13  | W13   | NE60.2°             | 181.43              | 101.84/79.59                          | 7.49               | Vertical        |
| 14  | W14   | NE53.5°             | 220.84              | 111.92/108.92                         | 5.77               | Vertical        |

/: data not acquired.
curves” section (Figure 8). The corresponding fracture morphology of descending (W2) and stable (W8) curve is relatively simple, with one main fracture (blue) and few branch fractures (Figure 8(a2) and (b2)). However, the ascending (W13) and wavy (W9) curves are more likely to form complex multi-directional propagated fractures with many branch fractures (e.g. red, yellow, and purple in Figure 8(c2) and (d2)), which is consistent with the fracture propagation as shown in Figure 5(a) to (c) and may in turn limits the main fracture growth and reservoir permeability (Cai et al., 2014).

Effect of in-situ stress on fracture morphology. The hydraulic fracture propagation behavior in coal seam is greatly affected by in-situ stress. Due to the similar fracturing engineering and petrophysics of CBM reservoirs, the fracture propagation characteristics can be evaluated from the perspective of in-situ stress. The tectonic stress field of the Zhengzhuang block in the Qinshui Basin has inherited the moderate and advanced stages of Himalayan compression-tectonic stress (NEE–SWW direction), and the tectonic deformation strength gradually weakens from the SE to the NW (Qin et al., 2001; Su et al., 2005). The azimuth of the maximum horizontal in-situ stress in the southern Qinshui Basin is NE–SW direction (Yu, 2010). The main fracture azimuth of 14 appraisal wells is concentrated between NE 50° and NE 90°, namely NE–NEE direction (Figure 9(a) and (b)), which shows that the fracture orientation is basically consistent with the direction of maximum horizontal in-situ stress (Chen et al., 2014). The injected fracturing fluid first propagates in the pre-existing natural fractures and then forms the main fracture that tends to the direction of the maximum in-situ stress, which indicates that the maximum in-situ stress direction should be the dominant factor controlling the hydraulic fracture orientation.

All hydraulic fractures of the 14 CBM appraisal wells are vertical indicating that the vertical in-situ stress is greater than the horizontal in-situ stress in the shallow coal seam with burial depth less than 2000 m in the Zhengzhuang block. The relationship between the burial depth and the closure stress measured by well test shows that the closure stress reflecting the minimum horizontal in-situ stress increases with increasing burial depth. This restricts the hydraulic fracture propagation, which means that a negative correlation between the fracture length and burial depth of the coal seam existed (Figure 10(a)). These laws are regional and applicable to unit A, which can provide reference for future hydraulic fracturing design of this area. According to equations (1) and (4), the closure stress of all the development wells slightly increases with the increasing burial depth of coal seam, which is in line with the 14 appraisal wells (Figure 10(b)). In addition, the vertical in-situ stress of descending and stable-type curves is distinctly larger than the closure stress, while the relationship of wavy and ascending-type curves is unsharp and abnormal (Figure 10(b)). Descending and stable-type fracturing curves should be easy to form stable vertical hydraulic fractures in a relatively simple stress environment. However, the fracture morphology of wavy and ascending-type curves may be complex and changeable.

PB, PISI, Pp, and PF can be acquired from the fracturing curves of the 265 development wells, and FB and FP can be calculated by equations (2) and (3). Statistical results of the average values of FP and PISI of different types of fracturing curves indicate ascending type > wavy type > stable type > descending type (Figure 11). PISI can be approximated to the minimum horizontal in-situ stress (Nolte, 1979), and the smaller the value of FP, the better development the hydraulic fracture is. Therefore, the minimum horizontal in-situ stress should be small for the area with descending and stable-type fracturing curves concentrated. At the same engineering condition, hydraulic fractures corresponding to these
Figure 8. Typical fracturing curves of four appraisal wells (a1, b1, c1, and d1) and their corresponding 3D top view of hydraulic fracture morphology (a2, b2, c2, and d2) (location of appraisal well W2, W8, W9, and W13; see Figure 9(a)).
two type curves tend to propagate stably. On the contrary, for the wavy and ascending-type fracturing curves concentrated area, the minimum horizontal in-situ stress is large, which may hinder the fracture propagation and cause the fluctuation or high pressure. Although there is no significant difference in the average value of $F_B$ corresponding to the four types of fracturing curves (Figure 11(c)), the descending-type curves have a higher average value of $F_B$ while the ascending-type curves have a lower one. This result may explain the distinct and inconspicuous $P_B$ in descending and ascending fracturing curves, respectively (Figure 4 (b) and (d)).
Impacts of hydraulic fracturing on gas productivity

The first gas production peak. There are usually gas production peaks in CBM production curves, which could reflect the gas production potential qualitatively. Most of high-yield CBM wells own the “double peaks” characteristics of production curve. The first gas production peak ($Q_1$) is generally related to the coal reservoir fracturing effect. Coal seam with better fracturing effect is more likely to form fractures with large leakage radius in the near wellbore area, which also benefits for water drainage, reservoir pressure decrease, and desorption and gas production. Therefore, the value of $Q_1$ is positively correlated with the CBM well fracturing effect (Tao et al., 2011).

As for the four typical fracturing curve mentioned in “Fracturing curves” section, well Z1 (descending type) shows a smooth fracture propagation during the fracturing, and the stimulation effect of the CBM reservoir is remarkable. The daily gas production rises and

Figure 10. (a) Scatter diagram of coal seam burial depth, closure stress, and fracture length; (b) scatter diagram of in-situ stress and coal seam burial depth of different types of fracturing curves.

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Figure 11. Stock chart of stress-change characteristics of all the 265 development wells with different fracturing curve types: (a) instantaneous shut-in pressure; (b) propagation pressure gradient; (c) break-down pressure gradient.
reaches to the first peak rapidly. This well remains high gas yield, and the daily average gas production ($Q_a$) is above 2500 m$^3$/d during the drainage period (Figure 12(a)). Well Z2 (stable type) has relatively stable propagated hydraulic fractures, and the daily gas production quickly reaches to $Q_1$ (1915 m$^3$/d). However, the subsequent gas productivity is insufficient due to the limited fracturing range. The daily gas production of well Z2 has been declining until drainage measures conducted (Figure 12(b)). For wells Z3 (wavy type) and Z4 (ascending type), because of the discontinuous propagation of hydraulic fractures in the near wellbore area, the effective leakage radius is small. $Q_1$ of the two wells is low (1210 and 877 m$^3$/d, respectively), and the daily gas production fluctuates greatly and decreases rapidly (Figure 12(c) and (d)).

**Effective conductivity and average daily gas productivity.** To evaluate fracturing effect through gas productivity, $P_{ISI}$, $P_F$, and $V_p$ of 61 continuously produced development CBM wells were synthetically analyzed. Results show that the average pressure drop rate of the 61 CBM wells is 3.67 MPa/h. The mean values of $P_{ISI}$, $P_F$, and $V_p$ of different kinds of fracturing curves all indicate the same relationship of ascending type > wavy type > stable type > descending type (Figure 13). The wavy and ascending-type fracturing curves are mostly distributed in the areas where the geological structure is severe, tectonic coal, and faults are well developed, which exhibits relatively large $P_{ISI}$ and $P_F$, namely the higher closure stress and formation pressure in coal seam. For example, the average value of $P_{ISI}$ of wavy and ascending-type fracturing curve is as high as 17.47 and 20.85 MPa, respectively.
Figure 13. Stock chart of stress change characteristics of 61 continuously grained development wells with different fracturing curve types after pump stop: (a) instantaneous shut-in pressure; (b) formation pressure; (c) pressure drop rate.
This result indicates that the proppant can be easily embedded in coal seam or be broken and then reducing the effective conductivity of hydraulic fractures. Moreover, wavy and ascending-type fracturing curves show a relatively high mean value of $V_p$ (Figure 13(c)). On one hand, the fracturing fluid loses fast under the influence of multi-directional propagated fractures and seemingly reflects the well conductivity of fractured CBM reservoirs. However, the multi-directional propagated fractures merely develop in the near wellbore area (Figure 5); the actual fracturing effect on coal reservoir is less and thus contributes little to the gas productivity. On the other hand, the higher pressure drop rate also represents the smaller reservoir pressure coefficient. Furthermore, high pressure drop rate may cause reservoir sensitivity or proppant embedded, which will reduce the effective conductivity of hydraulic fracture.

The conductivity of hydraulic fracture directly affects the coal seam water production and reservoir pressure drop during the drainage process of CBM wells, which in turn affects the gas desorption and output. The 61 selected CBM production wells have been continuously produced for 600 days after hydraulic fracturing, and the production schemes of which are basically the same. Therefore, the average daily gas production rate can be used to

### Table 2. Production characteristics corresponding to different fracturing curve types in the Zhengzhuang block.

| Fracturing curve type | Number of wells | Max   | Min   | Average |
|-----------------------|-----------------|-------|-------|---------|
| Descending            | 19              | 2734  | 398   | 805     |
| Stable                | 24              | 1481  | 232   | 620     |
| Wavy                  | 10              | 1005  | 207   | 551     |
| Increasing            | 8               | 1027  | 229   | 475     |

(Figure 14(a)). This result indicates that the proppant can be easily embedded in coal seam or be broken and then reducing the effective conductivity of hydraulic fractures. Moreover, wavy and ascending-type fracturing curves show a relatively high mean value of $V_p$ (Figure 13(c)). On one hand, the fracturing fluid loses fast under the influence of multi-directional propagated fractures and seemingly reflects the well conductivity of fractured CBM reservoirs. However, the multi-directional propagated fractures merely develop in the near wellbore area (Figure 5); the actual fracturing effect on coal reservoir is less and thus contributes little to the gas productivity. On the other hand, the higher pressure drop rate also represents the smaller reservoir pressure coefficient. Furthermore, high pressure drop rate may cause reservoir sensitivity or proppant embedded, which will reduce the effective conductivity of hydraulic fracture.

The conductivity of hydraulic fracture directly affects the coal seam water production and reservoir pressure drop during the drainage process of CBM wells, which in turn affects the gas desorption and output. The 61 selected CBM production wells have been continuously produced for 600 days after hydraulic fracturing, and the production schemes of which are basically the same. Therefore, the average daily gas production rate can be used to

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evaluate the fracturing effect. The different types of hydraulic fracturing curves and average daily gas production of the 61 CBM wells are summarized in Table 2. The gas production corresponding to the four type fracturing curves has the relationship of 
descending type > stable type > wavy type > ascending type. For each CBM well, the scale of the color spots in Figure 14(a) means the amount of $Q_a$ in the plane distribution of CBM production wells with different fracturing curve types. High gas production wells (corresponding to descending and stable fracturing curves) are mainly concentrated in the uplift zone with moderate geological structure and the transition zone between the slope zone and the uplift zone. Pattern 1 in Figure 14(b) means that the favorable fracturing effect normally has effective fracture propagation, relatively high $Q_a$, and long gas production time. Low production wells (corresponding to wavy and ascending fracturing curves) that correspond to Pattern 2 (Figure 14(b)) are mainly located in the fault zones with strong tectonic deformation in Figure 14(a), in which multi-branches may lead to limited fracturing effects, large fluctuation in gas production, and low $Q_a$. Therefore, this work may benefit for the follow-up CBM well spacing and adjustment of gas production measures, especially for the Zhengzhuang Block in the southern Qinshui Basin, North China.

Conclusions
The fracturing curves, microseismic monitoring, in-situ stress parameters, and gas productivity were adopted to evaluate the fracturing effect. The fracturing curves and their relationship with in-situ stress and gas productivity were elaborated. The following conclusions can be made:

1. According to the geological structure, the CBM development unit A of the Zhengzhuang block in the Qinshui Basin is divided into slope zone, uplift zone, and fault zone. The fracturing curves of 265 development wells in the study area are classified into ascending, stable, descending, and wavy types according to the fracturing pressure variations.
2. From the NW slope zone to the middle uplift zone then to the SE fault zone, the proportion of the stable and descending-type curves in the corresponding zone gradually decreases while the ratio of the wavy and ascending curves rapidly increases. The four types of fracturing curves of the development wells are locally distributed, which are directly related to the geological structure, in-situ stress, reservoir heterogeneity, and pre-existing natural fractures.
3. The main hydraulic fractures of microseismic monitoring for 14 CBM appraisal wells show that the fracture azimuth is closely consistent with the direction of the maximum in-situ stress. For the wavy and ascending curves, the abnormal relationship between the closure stress and the vertical in-situ stress is the main cause for the development of multi-branches, which restrict the propagation of hydraulic fractures in length, width, and height.
4. Based on the first gas production peak, the descending curve should have the best fracturing effect, while the ascending curve corresponds to the worst. The average values of $F_P$ and $P_{ISI}$ of 265 CBM development wells indicate that the fracturing effect has a rule of descending type > stable type > wavy type > ascending type. Moreover, the mean values of $P_{ISI}$, $P_F$, and $V_p$ of 61 continuous produced CBM wells with different fracturing curves show the same relationship, which also has the same gas production rate pattern of descending type > stable type > wavy type > ascending type.
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