Study on the Interference Law of Staged Fracturing Crack Propagation in Horizontal Wells of Tight Reservoirs
Shaohua Gai, Zhihong Nie, Xinbin Yi, Yushi Zou, and Zhaopeng Zhang*

ABSTRACT: Horizontal well multistage fracturing technology is a high-efficiency method for tight oil and gas production, which increases the contact area between the wellbore and stratum by forming multiple transverse hydraulic fractures (HFs). The stress interference caused by the created HFs will affect the propagation geometries of the subsequent HFs, and then affect the overall fracturing treatment performance. In order to study the distribution of HFs and law of interference among multiple fractures during horizontal well multistage fracturing in tight reservoirs, in this paper, the effects of horizontal stress difference, perforation spacing, and net pressure in the created fracture on the initiation and propagation of multiple cracks were specially studied through large-scale hydraulic fracturing experiments and numerical simulation. The results showed that under high horizontal stress difference, multiple HFs with small spacing tended to coalesce at a place where the length has extended to a certain level. It was also found that the initiation pressures of HFs within subsequent stages increase with the rise of net pressure in created HFs, which causes the subsequent fractures to deviate from the direction perpendicular to the horizontal wellbore and then to gradually deflect toward it. Moreover, the ratio of fracture spacing to fracture height, and the net pressure are the key parameters to determine the deflection degree of HFs for multistage fracturing. In addition, the deflection degree of subsequent HFs was expected to enhance with the decreasing ratio of fracture spacing to fracture height and increasing net pressure in created HFs. It was useful for mitigating stress interference to lengthen the stage spacing, control the fracture height, and reduce the net pressure. The research results have a reference value for the optimal design of the fracture spacing for multistage fracturing.

1. INTRODUCTION
Horizontal well multistage fracturing is the most commonly used technology to enhance the production and reservoir stimulation for tight oil and gas reservoirs.1 In 2008, Meyerofer et al.2 proposed the concept of stimulated reservoir volume (SRV). Cipolla et al.3,4 pointed out that the SRV is positively correlated with production, which has been confirmed by field tests. However, the production logging of multistage fracturing wells showed that there is a large gap in the contribution rate of hydraulic fractures (HFs) in different stages to total production.5 This is because stress interference suppresses the initiation of several perforations, prevents HFs in the middle of the wellbore from extending, and induces the deflection of HFs situated in either end of the horizontal segment.6,7 The induced stress may lead to the asymmetrical propagation of both wings of a single fracture during multistage fracturing, which will affect the SRV significantly. Moreover, Somanchi et al.8 and Weddle et al.9 reported the results of the field test of the small-spacing stimulation for the Bakken shale gas. The results showed that the production increased significantly under the cluster spacing of 5 m, but it was not confirmed whether the multicluster fractures could effectively grow in the reservoir. This paper studies the initiation and propagation law of HFs during horizontal multistage hydraulic fracturing and examined the influence of stress interference on multiple fracture propagation. Based on the conclusions obtained, the relationship between fracture complexity and operational parameters could be confirmed to provide guidance for the optimization and design of fracturing treatment parameters.

Received: December 23, 2019
Accepted: April 22, 2020
Published: May 1, 2020
carried out the physical simulation experiment of multicluster fracture propagation by using artificial specimens. The results verified that there is stress interference during the growing of multicluster HFs and the propagation of intermediate fracs is inhibited. In some studies on perforations, Brumley and Abass explained the fracture initiation mechanism based on the results of laboratory physical simulation experiments, and analyzed the effects of the perforation diameter, perforation density, and phase angle on the initiation of HFs. In addition to laboratory experiments, the researchers have also conducted numerical simulations of multiple fracture propagation. Olson proposed a boundary element model for the simulation of multicluster fracture propagation with stress interference considered. Wu and Olson modified the model with the consideration of perforation and wellbore friction and found that stress interference made the width and length of the intermediate fracture narrower and shorter than those of HFs at the end of one stage. Lecampion carried out the numerical simulation of the amount of fluid into multicluster fractures based on the boundary element model and suggested that adjusting the perforation distribution and increasing perforation friction are beneficial to the equilibrium of fluid into each cluster. Long and Xu considered the perforation corrosion on the basis of the multicluster fracture propagation model. In addition, the optimization of multicluster HFs in the field is mainly conducted through the test, which is a kind of high-cost trial research and does not facilitate the study of general rules.

In summary, when multiple tightly spaced HFs are formed, the formerly created HFs can lead to the deflection of the HFs in the subsequent stages, with the following HFs even growing along the horizontal wellbore, instead of the direction perpendicular to the wellbore, to form a longitudinal fracture. However, within the same stage, the HFs from the intermediate clusters are subjected to higher compressive stress, which leads to a narrower fracture width and decreased conductivity. Moreover, it even inhibits the HF growth and makes them coalesce, resulting in a nonuniform stimulation of reservoirs along the horizontal segment and a reduced production after the treatment. Although a great deal of theoretical studies have been carried out on the initiation and propagation of HFs for horizontal well multistage fracturing, few of the most direct physical experiments have been conducted to verify those conclusions. In addition, the influence of fluid pressure in the formerly created HFs on the distribution of multiple fractures within the subsequent stages has not been involved in the present studies for horizontal well multistage fracturing. Aiming at the above problems, this paper studied the influences of horizontal stress difference and fluid pressure in formerly created HFs on the HF propagation geometries in horizontal well multistage fracturing based on true tri-axial hydraulic fracturing modeling experiments and numerical simulations.

2. RESULTS AND DISCUSSION

2.1. Experiment of Fracture Propagation in Horizontal Well Multistage Fracturing. 2.1.1. Effect of High Horizontal Stress Difference under Low Net Pressure in Formerly Created HFs. In this experiment, the net pressure of the formerly created HFs was declined to zero through decompression, which assured that the fluid pressure was lower than the closure stress to maintain the formerly created HFs closed, and then the next stage was fractured. This part mainly analyzed the influence of high horizontal stress difference on the initiation and propagation of multiple fractures, and Figure 1 is a schematic diagram of fracture geometries of no. 1 specimen after being fractured. Under the high horizontal stress difference, HF1 (initiated from the first stage) propagated along the horizontal maximum principal stress, forming a transverse fracture perpendicular to the horizontal wellbore; the HF2 and HF3 coalesced with HF1 at a distance away from the wellbore. Moreover, HF2 and HF3 were observed to be tortuous and narrow, which means the propagation of subsequent HFs were greatly affected by the formerly created HFs. According to the pressure–time curve of no. 1 specimen shown in Figure 2, the initiation pressures of HF2 and HF3 were slightly higher than that of HF1, indicating that the initiation and propagation of the subsequent fractures were affected by the induced stress from the created fracture. It was also observed that the extending pressure of HF1 was low and stable, about 2 MPa, confirming that HF1 was straight and wide. However, the extending pressures of HF2 and HF3 were both higher than that of HF1 and fluctuated, revealing that HF2 and HF3 were tortuous and narrow, which was consistent with the observation in the experiment.

2.1.2. Effect of Low Horizontal Stress Difference under Low Net Pressure in Formerly Created HFs. Under low horizontal stress difference, HF1 of no.2 specimen was a transverse fracture perpendicular to the horizontal wellbore, as shown in Figure 3. The HF1 was in critical closure when the net pressure in HF1 declined to 0. It was found that the path of HFs in the subsequent stages gradually deviated away from HFs created in the former stages at a distance from the wellbore, that is, HF2 deflected away from HF1. Besides, the subsequent HFs were compressed by the stress induced by formerly created HFs, causing a narrower width of the subsequent HFs within no. 2 specimen. By comparing the
results of no. 1 specimen with those of no. 2 specimen, it was concluded that multiple HFs with small spacing tended to coalesce under high horizontal stress difference. From the pressure−time curve shown in Figure 4, the initiation pressure of HF2 and HF3 was increased by 4.9 and 15.9%, respectively, comparing with that of HF1. In addition, the extending pressure of all three fractures fluctuated violently, indicating that the paths of the following fractures were tortuous and narrow, and importantly that the induced stress field had a larger effect on the propagation of the subsequent fractures in low horizontal stress difference.

2.1.3. Effect of Larger Stage Spacing under Low Net Pressure in Formerly Created HFs. The stage spacing of no. 3 specimen was 5 cm, which was used to analyze the influence of larger stage spacing on the initiation and propagation of multiple HFs, and Figure 5 is a schematic diagram of fracture geometries of no. 3 specimen after being fractured. HF1 and HF2 were observed to be approximately transverse and perpendicular to the wellbore, while HF3 deflected away from HF2. Because HF3 was subjected to the superposition of stress interference from HF1 and HF2, the path of HF3 deviated and the width reduced. However, the overall stress interference level in no. 3 specimen was obviously less intense than that of no. 1 and no. 2 specimens. By comparing the results of no. 3 specimen with those of no. 2 and no. 3 specimens, it was shown that the effect of interference among multiple fractures on the initiation and propagation of HFs was relatively weak under large stage spacing, which meant the HFs tended to grow approximately in the direction of horizontal maximum principal stress. It was also noted that although the net pressure of the formerly created HFs has reduced to 0 (critical closure), the horizontal minimum principal stress surrounding the formerly created HFs, especially in the vicinity of the wellbore, still could be enhanced to make it hard for the subsequent HFs to initiate and propagate, leading to an obvious deflection. According to the pressure−time curve shown in Figure 6, it was seen that the initiation pressure of each HF was almost identical and the extending pressure gradually decreased in all stages by a small magnitude, indicating that the stress interference between two adjacent fractures was mitigated in the case of larger stage spacing.

2.1.4. Effect of High Horizontal Stress Difference under High Net Pressure in Formerly Created HFs. In no. 4 specimen, the formerly created HFs were maintained completely open through the independent injection into them at a constant rate, under which the next stage was fractured. Under a high horizontal stress difference and small stage spacing (s = 2 cm), the experiment of no. 4 specimen was compared with that of no. 1 to explore the effect of a high horizontal stress difference on the initiation and propagation of multiple HFs under a higher net pressure in formerly created HFs. Figure 7 is a schematic diagram of fracture geometries of no. 4 specimen after being fractured. It was observed that HF1 propagated transversely and symmetrically about the wellbore, but HF2 and HF3 tended to grow downward after being initiated. In addition, the paths of HF2 and HF3 greatly deviated away from HF1. Compared with the no. 1 specimen, the initiation pressure of each stage of no. 4 specimen was

![Figure 3](image1.png)  
**Figure 3.** Propagation pattern of multiple fractures in no. 2 specimen.

![Figure 4](image2.png)  
**Figure 4.** Pressure−time curve in no. 2 specimen.

![Figure 5](image3.png)  
**Figure 5.** Propagation pattern of multiple fractures in no. 3 specimen.

![Figure 6](image4.png)  
**Figure 6.** Pressure−time curve in no. 3 specimen.

![Figure 7](image5.png)  
**Figure 7.** Propagation pattern of multiple fractures in no. 4 specimen.
higher, as shown in Figure 8, which indicated that a higher net pressure in the formerly created HFs could cause a larger increment of horizontal minimum principal stress, leading to a more intense stress interference.

HF1 of no. 4 specimen was initiated at the upper perforation of the horizontal wellbore, from which most fluid flew into HF1. Therefore, the upper wing of HF1 propagated adequately and possessed a wider width. However, the width of the other wing was narrow. Because of the large gap between the widths of upper and lower wings of HF1, the fluid pressure was unevenly applied onto the surface of HF1, which meant that the stress interference induced by the upper wing of HF1 was stronger than that of the lower wing of HF1. Consequently, the subsequent HFs tended to propagate into the region with weaker interference (downside of the wellbore). Compared with no. 1 specimen, it was clear that the subsequent HFs were subjected to stronger stress interference under a higher net pressure in formerly created HFs. Moreover, the subsequent HFs deflected at a larger angle and would not deviate along the direction of horizontal maximum principal stress under higher net pressure in formerly created HFs.

2.2. Numerical Simulation of Propagation Geometries in Horizontal Well Multistage Fracturing. 2.2.1. Effect of Horizontal Stress Difference. Horizontal stress difference is an important factor to control the direction of fracture propagation. By setting 5 MPa net pressure and changing the magnitude of horizontal stress difference (2, 5, and 10 MPa), the fracture propagation geometries in horizontal well multistage fracturing were simulated, as shown in Figure 9. By comparing the fracture propagation geometries under different conditions, it was shown that HF2 and HF3 deviated significantly under the horizontal stress difference of 2 MPa, among which the lateral deviation distance of HF2 was 6 m and the width of HF2 was 7 mm. This was because under a low horizontal stress difference, the induced stress field generated by HF1 had a greater influence on the propagation of HF2 than the in situ stress field, and the region of induced stress was larger. The lateral deviation distances of HF2 and HF3 were 3 and 2 m, respectively, indicating a smaller deflection angle. This was because the impact of the induced stress field generated by formerly created HFs was weakened under a horizontal stress difference of 5 MPa. Under a horizontal stress difference of 10 MPa, it

![Figure 8. Pressure−time curve in no. 4 specimen.](image)

![Figure 9. Fracture geometries under (a) Δσ = 2 MPa, (b) Δσ = 5 MPa, and (c) Δσ = 10 MPa.](image)
was indicated that the in situ stress had a dominant effect on the fracture propagation, with the lateral deviation distances of HF2 and HF3 2 and 1 m, respectively. Although the coalescence of multiple fractures was not realized in the numerical simulations, the results were also consistent with those in no. 1 and no. 2 specimens, indicating that the fracture geometries were dependent on the magnitude of the horizontal stress difference, that is, the nonplanar propagation and the complexity of the fracture geometries were gradually enhanced with decreasing horizontal stress difference. Combining the results of no. 2 specimen with the simulations, it was further confirmed that the inversion of the in situ stress field was easier to happen under a low horizontal stress difference, with fractures narrower and more tortuous.

2.2.2. Effect of Stage Spacing. The influence of stage spacing on the fracture propagation in multistage fracturing is mainly reflected by the ratio of stage spacing to fracture height. The fracture propagation under different ratios in sequential fracturing was simulated. The values of influencing factors are shown in Table 1, and the schematic diagrams of fracture propagation geometries under different conditions are shown in Figure 10.

Table 1. Parameters of Factors

| no. | s/h | Δσ (MPa) | pnet (MPa) |
|-----|-----|----------|------------|
| 1   | 1   | 5        | 5          |
| 2   | 1.5 | 5        | 5          |
| 3   | 3   | 5        | 5          |

By comparing different fracture propagation geometries, it was shown that the ratio of stage spacing to fracture height affects the fracture geometries in multistage fracturing. When the ratio was 1, HF1 was a straight fracture but HF2 and HF3 deviated. It was observed that HF2 and HF3 deflected toward the formerly created HF because the propagation was greatly affected by the induced stress in the earlier stages, in which HF2 had the maximum deflection amplitude with a lateral deviation distance of 3 m, but 1.5 m for HF3. However, because of the weakened induced stress at the end of propagation, HF2 and HF3 deflected away from the formerly created HF under the in situ stress, with a small deviation distance of 0.5 m. It was noted that HF2 closed to some degrees under the combined compression of HF1 and HF3 after HF3 formed. In addition, the width of HF2 was narrower than that of HF1 and HF3, which indicated that the width of HF2 near the wellbore was about 2.5 mm but the widths of HF1 and HF3 were 3.5 mm. It was also concluded that the stress interference was gradually weakened with increasing ratio, which indicated that the induced stress surrounding HF2 and HF3 was weak and the propagation geometries of them tended to be straight with a width of about 4 mm. The results above mentioned were in accordance with those in no. 3 specimen, indicating that the subsequent fracture was affected less by the induced stress because of the large spacing, with the growing path straight and complexity decreased. Therefore, in the field treatment, the fracture spacing should be reduced reasonably, to enhance the interference among multiple fractures and increase the complexity of HF.

Figure 10. Fracture geometries under (a) s/h = 1, (b) s/h = 1.5, (c) s/h = 3.
It has been discussed above that the stage spacing has a great influence on the fracture propagation geometry in multistage single-cluster sequential fracturing, while in multistage multi-cluster sequential fracturing, the stage spacing has more significant influences on the fracture propagation geometries because of a larger number of fractures and more complicated stress interference. Therefore, the propagation geometries in multistage multicluster sequential fracturing were simulated by changing the stage spacing, and the values of each factors are shown in Table 2. Figure 11 showed a fracture propagation geometry calculated under the above conditions. By comparing the different fracture propagation geometries, it could be seen that under the stage spacing of 50 m, three clusters of perforations in stage 1 were initiated and propagated simultaneously but the middle fracture was compressed by the other two HFs, which increased the fluid friction and caused a suppressed length of approximately 70 m. At the same time, the other two HFs both deviated outward at a small deflection angle because of the superposition of the induced stress field and the in situ stress field. In addition, in stage 2, the HF close to stage 1 was compressed and suppressed because of the superposition of induced stress generated by stage 1 and in situ stress, causing a length of about 80 m, but the HF away from stage 1 was not affected greatly, with a length of 150 m. Similarly, in stage 3, the two clusters of HFs close to stage 2 were compressed and suppressed because of the superposition of induced stress generated by stage 2 and in situ stress, causing a length of about 80 m, but the HF away from stage 2 was not affected greatly, with a length of 150 m. Meanwhile, the widths of HFs in the middle part were small, with a width of 7 mm. Nevertheless, when the stage spacing was 70 m, the stress interference among different stages was relatively small, but the fractures in the middle of each stage were still suppressed by the HFs on both sides, resulting in a shorter fracture length of about 60 m, and a narrower width of about 7 mm. Therefore, in the field fracturing, the larger stage spacing can facilitate the balance propagation of HFs.

2.2.3. Effect of Pressure in the Fracture. Pumping rate is one of the important parameters in the field treatment, which mainly affects the net pressure of the injected fluid, and then has a great influence on the pressurized rate and initiation time. The propagation geometries in horizontal well multistage fracturing were simulated by changing the net pressure in the fractures, and values of each factor are shown in Table 3.

Figure 12 showed a schematic diagram of fracture propagation geometries calculated under the above conditions. By comparing different fracture propagation geometries, it was shown that when the net pressure was 3 MPa, the HFs from three stages were nearly straight, and the lateral deviation distance of HFs from stage 2 and 3 was 1 m but the width of HFs from stage 2 was 7 mm. Furthermore, when the net pressure was 5 MPa, the lateral deviation distance of HFs from stage 2 and 3 was up to 3 m because of the enhanced induced stress generated by the formerly created HFs, and the width of HFs from stage 2 was 8 mm but 11 mm for HFs from stage 1 and 3. In addition, when the net pressure was 10 MPa, the lateral deviation distance of HFs from stage 2 and 3 was up to 4 m, and the width of HFs from stage 2 was 9 mm but 14 mm for HFs from stage 1 and 3. In conjunction with the experimental results in the four specimens, it was further convinced that the subsequent fracture tended to deflect at a large angle under a high net pressure in the created fracture. In addition, the subsequent fracture might be suppressed because of the uneven distribution of fluid pressure in the created fracture. Therefore, the higher pumping rate in the field fracturing can enhance the interference among the HFs and increase the complexity of the HFs.

### Table 2. Values of Factors

| no. | number of perforation clusters | segment spacing (m) | seam spacing (m) |
|-----|-------------------------------|---------------------|-----------------|
| 1   | 3                             | 50                  | 15              |
| 2   | 3                             | 70                  | 15              |

Figure 11. Fracture geometries under (a) $s = 50$ m, (b) $s = 70$ m.

### Table 3. Values of Factors

| no. | $p_{\text{net}}$ (MPa) | $\Delta \sigma$ (MPa) | $s$ (m) |
|-----|------------------------|-----------------------|---------|
| 1   | 3                      | 5                     | 20      |
| 2   | 5                      | 5                     | 20      |
| 3   | 10                     | 5                     | 20      |

2.3. DISCUSSION

The issue on the stress interference in the process of multistage hydraulic fracturing has been studied in many papers.
However, quite a few of them were performed through numerical simulations such as the boundary element method\textsuperscript{30,31} or displacement discontinuity method\textsuperscript{32,33}. In this article, a novel injection wellbore, with three clusters of perforations welded on it, was manufactured to model horizontal well multistage fracturing in the laboratory. The perforations facilitated the oriented initiation rather than random and uneven fracturing in open sections adopted in some studies\textsuperscript{25}. Moreover, fracture geometries could be directly observed in the laboratory through splitting, which is impossible in the field.

According to numerical results shown in Figure 9, it was apparent that the deviation of subsequent fractures from orthogonal to the wellbore was mitigated with increasing horizontal stress difference. Similar results were also obtained in some other studies\textsuperscript{24,30}. However, in conjunction with experimental results in no. 4 specimen, we found that the subsequent fracture tended to deflect away from the created fracture with a high net pressure even under high horizontal stress difference. This reflected that for one thing the in situ stress could even be diverted under a high horizontal stress difference when a high net pressure in the created fracture is maintained; for another, the propagation of subsequent fractures may be dominated by horizontal stress difference in the case of a low net pressure in created fractures, whereas a high net pressure may predominate the fracture propagation. Thus, net pressure in the created fracture is an essential factor to determine the growing path of the subsequent fracture.

Another finding was that monitored pressures presented a distinct response under different horizontal stress contrasts. The characteristics of pressure variation was able to illustrate some dynamic propagation processes such as interactions with natural fractures or bedding planes\textsuperscript{15,16}. From Figures 2 and 4, because of stress interference from previous fractures, the breakdown pressure in the subsequent stage was higher than that in the precedent stage, and it seemed that the breakdown pressure rose with increasing horizontal stress contrast. Bunger et al.\textsuperscript{25} also reported a similar trend of pressure increase consecutively in subsequent stages, particularly in blocks with the wellbore unnotched, and also stated that the notching may partially mitigate the breakdown pressure increase of subsequent fractures. Besides, the extending pressure fluctuated more violently under low horizontal stress contrast than under high contrast. In combination with fracture geometries observed, it was under a low horizontal stress contrast that the in situ stress field was easier to be diverted by induced stress and the subsequent fractures were narrower and more tortuous, increasing the flowing friction in the fractures.

As for the stage spacing, it was known that the stress interference was mitigated with increasing stage spacing. In this article, we verified that conclusion through experiments, and more importantly, we further explored the simultaneous propagation of multiple clusters of closely spaced fractures in the subsequent stage under different stage spacings by numerical simulations. It was concluded that under small stage spacing, the subsequent fractures would propagate unevenly, with fractures closer to the precedent stage.

![Fracture geometries under different net pressures](attachment:image.png)

**Figure 12.** Fracture geometries under (a) $p_{\text{net}} = 3 \text{ MPa}$, (b) $p_{\text{net}} = 5 \text{ MPa}$, (c) $p_{\text{net}} = 10 \text{ MPa}$. 

\textit{ACS Omega} http://pubs.acs.org/journal/acsodf

https://dx.doi.org/10.1021/acsomega.9b04423

ACS Omega 2020, 5, 10327–10338
suppressed but the far-end fracture could extend a long distance. In contrary, under a large stage spacing, the growth in the subsequent stage was similar to that in the precedent stage, with the middle fracture greatly suppressed but the fractures at the ends growing freely.

3. CONCLUSIONS

In order to deeply understand the fracture propagation law under stress interference in horizontal well multistage fracturing, based on the true tri-axial hydraulic fracturing simulation system, an indoor simulation experiment method for horizontal well multistage fracturing was proposed. In combination with numerical simulation, the influence of fluid pressure, horizontal stress difference, and stage spacing on the interference in horizontal well multistage fracturing was analyzed in detail. Also, the interference into the subsequent multiple fractures under high or low net pressure in the formerly created HFs was considered. According to the results in this paper, it was shown that it is of great significance to understand the fluid pressure and the proppant packers (or fracture width) in the formerly created HFs to optimize the timing and stage spacing of the subsequent fracturing stage. At high horizontal stress difference, multiple fractures tended to coalesce under small fracture spacing. With the increase of the net fluid pressure in the formerly created HFs, the initiation pressure of the HFs in subsequent stages increased, which caused the subsequent HFs to gradually deflect from the direction perpendicular to the horizontal wellbore to that along the wellbore. Besides, the ratio of fracture spacing to fracture height and net pressure are the key parameters to determine the deflection degree of HFs in multistage fracturing. The deflection angle increased under the smaller ratio and the greater net pressure. However, increasing stage spacing, controlling fracture height, and reducing net pressure can weaken stress interference.

4. EXPERIMENTAL AND COMPUTATIONAL METHODS

4.1. Fracturing Experiment Simulation. 4.1.1. Specimen Properties. The experiment was designed to simulate the fracture propagation of He8 formation of block 53 in the Sulige gas field, with an average permeability of 1.37 μD, an average tensile strength of 4.4 MPa, an average Young’s modulus of 25.8 GPa, and an average Poisson’s ratio of 0.227. Because it is difficult to obtain large-size natural tight sandstones with certain heterogeneity of the target layer, the artificial concrete specimens were prepared by using 40/70 quartz sand and G-class oil well cement. Considering the similarity between the artificial specimens and the tight sandstones of the reservoir, it is necessary to ascertain the optimal water–ash ratio by comparing all parameters of them, as shown in Table 4. Through drilling cores (Figure 13), permeability tests and mechanical property tests were carried out, and finally the no. 2 water–ash ratio was chosen as the optimal one, where the mass proportion for cement, sand, and water were 60, 20, and 20%, respectively. Adopting the water–ash ratio above, the properties of the artificial specimens were similar to those of rocks in the reservoir, with a permeability of 1.1 μD, a tensile strength of 4.4 MPa, a Young’s modulus of 25.03 GPa, and a Poisson’s ratio of 0.24.

4.1.2. Experiment Apparatus and Specimen Preparation. A large-scale true tri-axial hydraulic fracturing simulation system was used to carry out a horizontal well multistage fracturing experiment for 300 mm × 300 mm × 300 mm artificial specimens. In order to obtain a concrete specimen, the concrete was prepared based on the optimal water–ash ratio, and then was poured into the mold once the concrete was stirred well. Next, the multistage fracturing experimental wellbore was put into the concrete. In addition, the plates of the mold cannot be removed until the concrete completely solidify to obtain a concrete specimen (Figure 14a). The multistage fracturing experimental wellbore is a steel tube with an outer diameter of 1.5 cm, inner diameter of 0.8 cm, and length of up to 20 cm (Figure 14b). The external surface of the wellbore was treated with sand blasting and notch-cutting to enhance the cementing strength between the external surface and concrete, achieving a better cementation. In order to realize multistage fracturing, the rubber rings were used as the packers to isolate the interior of the wellbore into several independent stages. Because of the limitation of the specimen size and the experimental device, three pumping stages were considered in this study. Specifically, the interior of each stage was connected to the corresponding container full of fracturing fluid using the injection pipelines, guaranteeing the fluid injected into the stage separately during the experiments (Figure 14c). Four plane-fixed perforations were set perpendicular to the wellbore within each stage at the external surface (90° for phase angle). In addition, the perforations (1 m for perforation length), constructed by the pressure-bearing steel pipeline, were welded on the external surface and connected to the interior of the wellbore.

4.1.3. Experimental Procedure. It is difficult to apply the real in situ stress to the specimen. For the comparability of the results of experiments with those in the field, the horizontal stress contrast coefficient $K_h$, that is, $(\sigma_h - \sigma_h) / \sigma_h$, was adopted to design the magnitude of stress applied onto the specimen. In the experiment, $K_h$ was identical to that of the formation. Similar to the experimental configuration in fluid mechanics that the linear dimension in the model should be proportional to that in the prototype, the geometric similarity was adopted to design the fracture spacing between two adjacent perforations. In that way, the ratio of fracture spacing with respect to fracture length is equal to that in field. The
formulation of geometric similarity criterion is shown as follows

\[
\frac{S_M}{l_M} = \frac{S_F}{l_F} \tag{1}
\]

where \(S_M\) represents the fracture spacing in the experiment, \(S_F\) represents the fracture spacing in field, \(l_M\) represents the half length of the fracture in the experiment and \(l_F\) represents the half length of the fracture in field. Given that \(S_F = 40\sim 60\) m, \(l_M = 15\sim 17\) cm, and \(l_F = 200\sim 220\) m, based on formulation 1, \(S_M\) should be \(2.7\sim 5.1\) cm. Because the study focused on the effect of small spacing on the fracture propagation, \(S_M\) was eventually set as \(2.0\sim 5.0\) cm. In order to mitigate the near-wellbore effect of perforations on the fracture propagation, the perforation length was scaled up compared with the size of the wellbore and set as \(2.0\sim 5.0\) cm. According to the real-time pressure in field, the net pressure \(p_{net}\) was designed as \(0\sim 16\) MPa. In addition, the viscosity (63 mPa·s) of the fracturing fluid was the same as that in actual operation.

The experiment was conducted as follows

① Connect the pipeline and place the specimen into the chamber of the experimental system with the axis of the wellbore parallel to the X-axis.

② Push the hydraulic piston into the chamber along the X-axis, apply the vertical stress \(\sigma_v\), the maximum horizontal principal stress \(\sigma_{H1}\) and the minimum horizontal principal stress \(\sigma_h\) along the Z-, Y-, and X-axis, respectively, up to preset values and maintain stable.

③ Connect three injection pipelines inside the experimental wellbore to a multiport valve (no. 1) and also connect three intermediate containers full of fracturing fluid of different colors (mixed with dyes) to the multiport valve (no. 1).

④ Open the valves to which the injection pipeline in the current stage and the corresponding intermediate container connect, and keep the rest of valves closed. Then, turn on the injection system (no. 1) and pump fracturing fluid with a viscosity of 63 mPa·s into the wellbore at a constant rate of 50 mL/min before the accumulative injection volume for a single stage reaches 120\sim 160\) mL. During the whole pumping process, record the variation of wellbore pressure with a pressure transducer. When the accumulative injection volume reaches a preset amount and the pressure fluctuates slightly, stop pumping and close the valves to which the injection pipelines connect.

⑤ Repeat step ① when the second stage is to be fractured; when the third stage is to be fractured, adjust the corresponding valves, apply step ① to the first and second stage, and repeat step ⑦.

⑦ At the end of the experiment, the specimen is removed. The HFs from different stages are identified according to the color of dye of the fracture surface, and the propagation path of multiple fractures near the horizontal wellbore is analyzed through rock splitting and the pressure–time curves. The specific experimental scheme is shown in Table 5.
Table 5. Experimental Parameters

| no. | $\sigma_{ii}$ (MPa) | $\sigma_{ij}$ (MPa) | $\sigma_{ij}$ (MPa) | $\Delta\sigma_{ij}$ (MPa) | $K_i$ | $s$ (cm) | $P_{in}$ (MPa) |
|-----|---------------------|---------------------|---------------------|---------------------------|------|---------|--------------|
| 1   | 20                  | 8                   | 16                  | 8                         | 1    | 2       | 0            |
| 2   | 20                  | 8                   | 10                  | 2                         | 0.25 | 2       | 0            |
| 3   | 20                  | 8                   | 10                  | 2                         | 0.25 | 5       | 0            |
| 4   | 20                  | 8                   | 16                  | 8                         | 1    | 2       | 16           |

4.2. Calculation Model of Multifracture Propagation Geometries. 4.2.1. Displacement Discontinuity Model. For a three-dimensional nonplanar fracture with a length of L and a height of H, then it is equally divided into N elements along the length, with the half length of each element equal to a. The coordinate of the center of each element is $(x_i, y_i, z_i)$, $i = 1, 2, ..., N$. The schematic diagram of the coordinate system and fractures are shown in Figure 15. For such elements, the displacement discontinuity is defined as

$$
D_i = u_i(s, 0^+) - u_i(s, 0^-), \quad |s| \leq a
$$

where $D_i$ is the tangential displacement discontinuity, $u_i(s, 0^+)$ is the normal displacement discontinuity, $u_i(s, 0^-)$ is the lower surface of the fracture, $0^+$ is the upper surface of the fracture.

The stress generated by $N$ displacement discontinuous quantities at the element $i$ is

$$
\begin{align*}
\sigma_{ii}^i &= \sum_{j=1}^{N} C_{ii}^j D_{ij}^j + \sum_{j=1}^{N} C_{ij}^j D_{ij}^j, \quad i = 1, 2, ..., N

\sigma_{ij}^i &= \sum_{j=1}^{N} C_{ij}^j D_{ij}^j + \sum_{j=1}^{N} C_{ij}^j D_{ij}^j
\end{align*}
$$

where $C_{ii}^j$, $C_{ij}^j$, $C_{ij}^j$, and $C_{ij}^j$ are the stress impact coefficients of the displacement discontinuity of element $j$ with respect to element $i$; $\sigma_{ii}^i$ is the tangential stress at element $i$ generated by $N$ displacement discontinuities, MPa; $\sigma_{ij}^i$ is the normal stress at element $i$ generated by $N$ displacement discontinuities, MPa.

In order to consider the effect of the fracture height, the stress correction factor is introduced as

$$
M^ii = \alpha \left[ 1 - \frac{d_{ij}^2}{(d_{ij}^2 + \omega H_j)^{\beta/2}} \right]
$$

where $d_{ij}$ is the distance between the centers of element $i$ and $j$; $H_j$ is the height of element $j$; $\alpha$, $\beta$, and $\omega$ are the correction factors, with the values of $\alpha = 2$, $\beta = 2$, and $\omega = 1.2$, respectively.

Finally, the stress field formula of the three-dimensional fracture is obtained as

$$
\begin{align*}
\sigma_{ii}^i &= \sum_{j=1}^{N} M^ii C_{ii}^j D_{ij}^j + \sum_{j=1}^{N} M^ii C_{ij}^j D_{ij}^j, \quad i = 1, 2, ..., N

\sigma_{ij}^i &= \sum_{j=1}^{N} M^ii C_{ij}^j D_{ij}^j + \sum_{j=1}^{N} M^ii C_{ij}^j D_{ij}^j
\end{align*}
$$

4.2.2. Fracture Boundary Conditions. The methods of multistage fracturing include single-cluster perforation fracturing and multicluster perforation fracturing. The multistage fracturing with single-cluster perforation is carried out stage-by-stage from the toe to the heel of a horizontal well. Only a cluster of fractures are formed from one stage. Therefore, considering that the fracture surface is compressed by the fluid, the surface force of the fracture is as follows

$$
\begin{align*}
\sum_{i=1}^{N} f_{n}^i &= -P_f

f_s^i &= 0
\end{align*}
$$

where $P_f$ is the fluid pressure, MPa.

Superpose the far-field stress and formula 6 to obtain the surface force of element $i$ as

$$
\begin{align*}
\sum_{i=1}^{N} f_{n}^i &= -\sigma_{ii}^i \cos^2 \theta + \sigma_{ij}^i \sin^2 \theta + \sigma_{ij}^i

f_s^i &= -(\sigma_{ii}^i - \sigma_{ij}^i) \sin \theta \cos \theta + \sigma_{ij}^i
\end{align*}
$$

where $\sigma_{ii}^i$ is the maximum horizontal principal stress in the far field, MPa; $\sigma_{ij}^i$ is the minimum horizontal principal stress in the far field, MPa; $\theta$ is the angle between element $i$ and the x-axis, rad.

Through formula 5–7, the $2N \times 2N$ matrix equation can be obtained, and the solution of displacement discontinuity of each element can also be obtained by the LU decomposition method, to acquire the stress field surrounding the supported fracture. The schematic diagram of the applied tractions to a single element is shown in Figure 16.

4.2.3. Fracture Propagation Direction. In this paper, the maximum tensile stress criterion was used to judge the direction of fracture propagation. The maximum tensile stress criterion is as follows

$$
K_1 \sin \beta + K_{II} (3 \cos \beta - 1) = 0
$$
where $\beta$ is the angle between the directions of the current fracture propagation and the original fracture, rad; $k_i$ and $k_{ii}$ are type I and type II stress intensity factors, respectively, MPa·m$^{0.5}$.

The fracture propagation direction angle is obtained by formula 9 as

$$\beta = \begin{cases} 0, & K_{ii} = 0, \\ \frac{2 \arctan\left(\frac{K_i/K_{ii}}{\sqrt{2}a}\right) - \text{sgn}(K_{ii})(K_i/K_{ii})^2 + 8}{4}, & K_{ii} \neq 0 \end{cases}$$

(9)

where $\text{sgn}$ is the symbolic function. Specifically, the function value is 1 under a positive variable; the function value is −1 under a negative variable; and the function value is 0 under a zero variable.

According to the displacement discontinuity model, the stress intensity factor of the fracture tip is as follows$^{35}$

$$\begin{align*}
K_i &= \frac{0.806E\sqrt{\pi}}{4(1 - \nu^2)\sqrt{2a}}D_{ip} \\
K_{ii} &= \frac{0.806E\sqrt{\pi}}{4(1 - \nu^2)\sqrt{2a}}D_{ip}^{II}
\end{align*}$$

(10)

where $E$ is the Young’s modulus, MPa; $\nu$ is the Poisson’s ratio, no dimension; $a$ is the half length of an element, m; $D_{ip}$ is the normal displacement discontinuous quantities of the elements of fracture tip, m; and $D_{ip}^{II}$ is the tangential displacement discontinuous quantities of the elements of the crack tip, m.

4.2.4. Fracture Propagation Velocity. The fracture propagation velocity is calculated by the subcritical fracture propagation model, and the subcritical fracture propagation model is as follows$^{20}$

$$V = A \left(\frac{K}{K_c}\right)^n$$

(11)

where $A$ is a constant, m/s; $n$ is the subcritical propagation index, no dimension; $K$ is the stress intensity factor of the fracture tip, MPa·m$^{0.5}$; and $K_c$ is the fracture toughness of the material, MPa·m$^{0.5}$.

For I−II mixed fractures, the stress intensity factor at the tip is

$$K = 0.5 \cos(\beta/2)(K_i(1 + \cos \beta) - 3K_{ii} \sin \beta)$$

(12)

### AUTHOR INFORMATION

#### Corresponding Author

Zhaopeng Zhang — State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China; orcid.org/0000-0002-8265-7131

#### Authors

Shaohua Gai — Research Institute of Petroleum Exploration & Development (RIPED) PetroChina, Beijing 100083, China; China United Coalbed Methane Co. Ltd., CNOOC, Beijing 100016, China

Zhihong Nie — China United Coalbed Methane National Engineering Research Center Co. Ltd., Beijing 100095, China

Xinbin Yi — Research Institute of Petroleum Exploration & Development (RIPED) PetroChina, Beijing 100083, China

Yushi Zou — State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.9b04423

### Notes

The authors declare no competing financial interest.

#### ACKNOWLEDGMENTS

This study is funded financially with the Major National Science and Technology Projects (number-2016ZX05047; number-2017ZX05039002-003).

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