Investigation and Application of High-Efficiency Network Fracturing Technology for Deep Shale Gas in the Southern Sichuan Basin

Zhiheng Zhao,* Youcheng Zheng, Bo Zeng, and Yi Song

ABSTRACT: The Longmaxi Formations in the Luzhou block located in the Southern Sichuan Basin exhibit thick shale formations and huge shale gas resources and have become one of the significant blocks for large-scale production of shale gas. However, due to the natural fractures and high in situ stress and horizontal stress differences, proppants are broken and embedded severely, and complex network fractures are difficult to form, so traditional hydraulic fracturing technology cannot meet the need for profitable development of deep shale gas. In order to increase the stimulated reservoir volume and improve fracture complexity, large-scale hydraulic fracturing experiments and fracture propagation numerical simulations have been conducted based on the geology and engineering treatment difficulty of the Luzhou block to discuss the main factors influencing fracturing effectiveness. Meanwhile, two round field tests were conducted to evaluate the fracturing effectiveness, and the following study results were obtained. First, in situ stress and horizontal stress differences are the main mechanical factors, while cluster spacing and proppant injection intensity are the main fracturing parameters. Therefore, multi-cluster perforation, high-intensity proppant injection, and diversion are employed to improve fracture complexity and conductivity, thus increasing effective fracture volume. Furthermore, the second round of field tests gained remarkable results. The “short-cluster spacing + high proppant amount + variable viscosity slick water + diversion” high-efficiency fracturing technology was formed, and the average test production got to $28.6 \times 10^4$ m$^3$/d, which represented a 64% increase over the first round. It concludes that the high-efficiency hydraulic fracturing technology contributes to increasing shale gas production, notably in the Luzhou block for deep shale gas, and provides reliable technology support and study direction for further technical optimization in this block.

1. INTRODUCTION

The Upper Ordovician Wufeng Formation and Lower Silurian Longmaxi Formation located in the southern Sichuan Basin exhibit huge shale gas resources. Multi-stage hydraulic fracturing in horizontal wells has been proved to be an efficient technology to stimulate the middle and shallow shale formations in the Changning–Weiyuan block since 2012, and the block has realized beneficial development. At present, the deep shale gas resource (the depth of 3500–4500 m) is being given a focus, and its resource amount is about $67 \times 10^4$ m$^3$/t. The Luzhou block is located in a low-steep tectonic belt, and the depth of the Longmaxi Formation is mainly 3500–4500 m. The shale formation is thick, becoming a significant block for shale gas large-scale production.

The Wufeng–Longmaxi Formations of the Luzhou block gradually deepen from north to south. The mineral composition is quartz, feldspar, calcite, dolomite, clay minerals, and pyrite, and the bottom of the Longmaxi Formation is dominated by biosiliceous minerals, which account for about 60−70% of its volume. The porosity mainly ranges from 4.0 to 6.5%, and both organic and inorganic pores are developed. The organic carbon content is about 2.8−6.0%, and the gas content is mainly between 5.0 and 7.5 m$^3$/t. The Young’s modulus and Poisson’s ratio of reservoir rocks are approximately 27–50 GPa and 0.13–0.24, which are generally characterized by a high Young’s modulus and low Poisson’s ratio. However, the horizontal stress difference of the Luzhou block is about 12–20 MPa that is higher compared with that of the Changning–Weiyuan block. According to the reservoir classification and evaluation standard of the Changning–Weiyuan block, type I formation (TOC > 3%, porosity > 5%, total gas content > 3 m$^3$/t, brittle mineral content > 55%) is the best shale formation. There are two continuous and stable class I formations in the Wufeng and Longmaxi Formations of the Luzhou block. The thickness is about 10−20 m, which is the main target formation for exploration and development at present.

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MPa, respectively, which is not conducive to form a complex fracture network during hydraulic fracturing. Besides, under the condition of high closure pressure, proppant embedment is serious and it is difficult to maintain fracture conductivity. The horizontal stress is more than 80 MPa in the Luzhou block, so higher requirements for proppant property and long-term fracture conductivity are put forward. Laboratory tests showed that some of the proppant was crushed under 80 MPa of closure stress. Also, according to three-dimensional (3D) laser scanning analysis, the maximum proppant embedment depth in a rock slab reaches 1 mm, and the effective propping for fractures is insufficient. Furthermore, the natural fractures are well developed, leading to low liquid efficiency during hydraulic fracturing. When the hydraulic fracture intersects with the natural fracture, it is easy to be captured and extended along the natural fracture. The fracturing fluid filtration is serious, and the amount of fluid used for fracture formation and sand transportation decreases, resulting in a small effective stimulation reservoir volume.

Based on the difficulties of shale reservoir stimulation in the Luzhou block, the integration method of geology and engineering was adopted to investigate the influence of cluster spacing, proppant injection intensity, and diversion on fracturing effectiveness. In addition, two field tests were designed to evaluate the production of horizontal wells.

## 2. HIGH-EFFICIENCY NETWORK FRACTURING TECHNOLOGY

A large-scale true triaxial experiment was conducted on a shale sample of the Longmaxi Formation to study hydraulic fracture propagation. The geometric dimension of the shale sample is $300 \times 300 \times 300$ mm. It is known from rock mechanics experiments that its uniaxial compressive strength is 84 MPa, its Young’s modulus is 40 GPa, and its Poisson’s ratio is 0.23. The experimental conditions are shown in Table 1. Before the experiment, a portable microscope was used to observe the geometry of natural fractures and measure their average on six surfaces of the shale sample. After the experiment, the same method was used to distinguish natural fractures and hydraulic fractures by the fracture morphology and change in fracture width. Based on the sketch and comparison of natural and hydraulic fractures shown in Figure 1, it is indicated that hydraulic fractures are captured by natural fractures and are easy to extend along them under the condition of high horizontal stress difference, and it is difficult to form a fracture network.

### Table 1. Experimental Conditions of the True Triaxial Experiment

| Sample     | Natural Fracture | Experimental Conditions |
|------------|------------------|-------------------------|
| 1 ($300 \times 300 \times 300$ mm) | Developed        | Vertical Stress $\sigma_x$, MPa: 19<br>Maximum Horizontal Stress $\sigma_{H}$, MPa: 22<br>Minimum Horizontal Stress $\sigma_n$, MPa: 10<br>Flow Rate, mL/min: 40<br>Fracturing Fluid: Slickwater<br>Viscosity of the Fracturing Fluid: mPa·s: 2 |

In order to improve the degree of fracture complexity and increase the stimulated reservoir volume (SRV), some scholars suggest that shortening the distance between perforating clusters and increasing the proppant injection amount is one of the most effective approaches. Intensive stage fracturing technology aims to shorten the cluster spacing by cutting the stage length under the same number of perforating clusters, but the number of stages increases to reduce the fracturing efficiency. However, the multi-cluster fracturing technology aims to achieve short-cluster spacing by increasing the number of perforating clusters within a stage. Therefore, the multi-cluster fracturing technology has been adopted to solve the key problems of deep shale reservoir fracturing.

## 3. RESULTS AND DISCUSSION

### 3.1. Multiple Perforation Clusters

Multi-fracture propagation is a complex process of fluid–solid coupling, and a schematic diagram is shown in Figure 2. In this study, some assumptions are made to improve computational efficiency: (1) injection fluid is the incompressible Newtonian fluid; (2) the fluid is one-dimensional flow in the fractures, which is affected by Carter filtration; and (3) the formation rock is homogeneous and uses a liner elastic material in the fracturing. The method for numerical simulation of hydraulic fracturing mainly includes a multi-cluster flow rate dynamic distribution model, an induced stress field model, determination of multi-cluster fracture tip propagation, and solution of a fluid–structure coupling model.

During the extension of multi-fracture, the balance of flow pressure obeys Kirchoff’s second law, including perforation friction, pressure drop in fractures, and wellbore friction.
Based on flow conservation in the clusters, the relationship between pressure and flow is expressed below\textsuperscript{12,13}:

\[ P_i = p_{\text{perf},i} + \Delta p_{\text{frac},i} + \sum_{j=1}^{n} p_j \] (1)

where \( p_{\text{perf},i} \) stands for perforation friction, \( \Delta p_{\text{frac},i} \) is the pressure of the fracture inlet in cluster \( i \), \( p_j \) is the wellbore friction of the segment \( j \), and \( \sum_{j=1}^{n} p_j \) is the pressure in well heel, \( Q \) is the total flow, and \( q_i \) represents the flow of cluster \( i \).

The volume of cluster \( i \) of multi-cluster fracture propagation is given by:

\[ \int_{0}^{t'} Q \, dt = \int_{0}^{L_{ij}(t)} - \frac{h_l w_l}{4} \, ds \]

\[ + \sum_{j=1}^{N} \int_{0}^{L_{ij}(t)} \int_{0}^{s(t)} q_i(s, t) \, ds \, dt \] (3)

where \( L_{ij} \) stands for the fracture length in cluster \( i \), \( N \) is the number of fractures, \( q_i \) is the viscosity of fluid filtration, \( h_l \) is the fracture height, \( w_l \) is the fracture width, \( s \) is the fracture element, and \( t \) is the fracturing time.

Induced stress is caused between clusters during multi-fracture propagation, and fracture elements are affected mutually. The equation of the induced stress field is below\textsuperscript{11}:

\[ \sigma_{ij} = \sum_{j=1}^{N} \frac{G}{\pi a_{ij}} \frac{D_{ij}}{D_n} + \sum_{j=1}^{N} \frac{M}{\pi a_{ij}} \frac{D_{ij}}{D_s} \] (4)

\[ \sigma_i = \sum_{j=1}^{N} G \frac{C_{ij}}{a_{ij}} D_{ij} + \sum_{j=1}^{N} M \frac{C_{ij}}{a_{ij}} D_{ij} \] (5)

where \( \sigma_n \) and \( \sigma_s \) stand for the normal stress and shear stress, \( G \) is the 3D correction factor, \( C_{ij} \) is the stress of the fracture element, and \( D_{ij} \) and \( D_{ij} \) are strains of the fracture element, and the value of \( i \) and \( j \) is \( 1-N \).

The stress intensity factor of the fracture tip is calculated first when the fracture is extended. The fracture tip increases an element if the condition of fracture propagation is met. The maximum circumferential stress criterion is expressed by the equivalent intensity factor:

\[ K_e = \frac{1}{2} \left[ K_f \left( 1 + \cos \theta \right) \cos \frac{\theta_f}{2} - 3K_{\text{II}} \sin \theta_f \right] \geq K_{\text{IC}} \] (6)

Based on the displacement discontinuity method, the stress intensity factor of \( K_f \) and \( K_{\text{II}} \) can be calculated \textsuperscript{[12–13]}:

\[ K_f = \frac{\sqrt{2\pi} G}{4\sqrt{\alpha}(1-\nu)} D_n \] (7)

\[ K_{\text{II}} = \frac{\sqrt{2\pi} G}{4\sqrt{\alpha}(1-\nu)} D_s \] (8)

where \( G \) stands for shear modulus of the formation rock, \( \nu \) is Poisson’s ratio, \( a \) is the half length of the discrete fracture element, and \( D_n \) and \( D_s \) represent the normal and shearing displacement discontinuities.

The volume of cluster \( I \) of multi-cluster fracture propagation can be expressed as:

\[ V_i = \sum_{j=1}^{n} h_s w_i s_{ij} \] (9)

where \( w_{ij} \) is the width of the fracture element \( j \) of cluster \( I \), \( s_{ij} \) is the length of the fracture element \( j \) of cluster \( I \), and \( n_i \) is the number of fracture elements.

Normal and shearing displacements are calculated by the induced stress field, and nonlinear equations of stress and flow pressure-coupled fields are calculated by the Levenberg–Marquardt iteration method. Based on this coupling model, fracture volume with different cluster spacings was obtained. The main basic model parameters are listed in \textbf{Table 2}.

\begin{table}[h!]
\centering
\caption{Main Basic Model Parameters}
\begin{tabular}{|l|c|}
\hline
\textbf{parameters} & \textbf{value} \\
\hline
average maximum horizontal stress, MPa & 108 \\
average minimum horizontal stress, MPa & 93 \\
average Young’s modulus, GPa & 42 \\
average Poisson’s ratio & 0.22 \\
fracture height, m & 15 \\
total injection rate, m³/min & 16 \\
cluster number & 3–15 \\
cluster spacing, m & 4–18 \\
perforation number per stage & 48 \\
fluid viscosity, mPa s & 2 \\
\hline
\end{tabular}
\end{table}

It can be seen from the simulation results in \textbf{Figure 3} that with the shortening of cluster spacing within a stage, fracture volume increases but the growth rate becomes slow. When the cluster spacing is shortened to 8–10 m, the increase in fracture volume begins to slow down, with a growth rate of just about 4–5%. Besides, through the morphology of multi-cluster fracture propagation (\textbf{Figure 4}), it is indicated that if the cluster spacing is too short, the fractures in the interior are greatly affected by the induced stress, which inhibits fracture extension forward and makes fractures in each cluster non-uniform. Therefore, considering the fracture volume and its uniform extension, the cluster spacing is designed by about 8–10 m.

\section*{3.2. Improving Proppant Injection Intensity.}

The deep shale reservoir in the Luzhou block has large in situ stress, and the proppant is easily broken and embedded at a high closure pressure, resulting in low long-term fracture conductivity and gas production. The reservoir stimulation practice of
unconventional oil and gas reservoirs at home and abroad shows that improving proppant injection intensity is beneficial to increase well production. The proppant injection intensity of Haynesville, the Permian Basin, Eagle Ford, and other major shale plays in North America is up to 5 t/m.\textsuperscript{16} According to the physical model experiment research (Formula 10), as the pumping rate increases, the flow rate in the fracture increases, the proppant is rolled up and suspended in the fracture fluid, and the sand bank height is smaller, which allows more proppant to enter the fracture and transport farther, increasing the length of the propped fracture.\textsuperscript{17,18} Therefore, a higher flow rate should be guaranteed under the conditions of the field.

\[ H_d = h_o \frac{Q}{w \times V_d} \]  \hspace{1cm} (10)

where \( H_d \) is the balance height of the sand bank, \( h_o \) is the fracture height, \( w \) is the fracture width, \( Q \) is the flow rate, and \( V_d \) is the balance velocity.

Besides, the viscosity of the fracturing fluid also has a significant effect on proppant transport and placement in fractures. According to Novotny’s velocity formula 11, when the viscosity of the fracturing fluid increases in the proppant injection period, the viscosity coefficient increases and the settlement velocity of proppant decreases, which is conducive for proppant transport to the end of the fracture. In addition, the viscosity of the proppant-carrying fluid increases, and the proppant is more easily suspended, which is helpful in increasing proppant injection intensity.\textsuperscript{19,20}

\[ V_p = \left[ \frac{d_p (\rho_p - \rho_f) g}{18K} \right]^{1/n} d_p \]  \hspace{1cm} (11)

where \( V_p \) is the settlement velocity, \( d_p \) is the diameter of the proppant, \( \rho_p \) and \( \rho_f \) are densities of the proppant and fracturing fluid, respectively, and \( K \) is the consistency coefficient.

In order to increase the conductivity of hydraulic fractures in deep shale reservoirs, a large flow rate and variable viscous slickwater with continuous or long-slugging proppant injection are adopted. The flow rate is increased to 16–17 m\textsuperscript{3}/min, and the viscosity of slickwater is increased to 20–30 mP\textperiodcentered s in the
proppant-carrying stage so as to improve the proppant injection intensity and achieve long-term effective propping for fractures.

3.3. Diversion Technology. Due to the influence of rock mechanics properties, in situ stress heterogeneity in the shale reservoir, and induced stress between clusters, there is a competitive relationship during fracture propagation, and some clusters are not opened or fully extended. Furthermore, production logging data show that the cluster efficiency in some stages is only 40−50%.21−23 In order to improve cluster efficiency and form more flowing passages, the diversion technology with plugging balls should be adopted.

The variation of the fracture volume of each cluster with time in a stage can be obtained through simulation, as shown in Figure 5. During multi-fracture propagation, the fracture volume tended to increase with the fracturing time, but only about half of the clusters were fully extended. The derivation of the fitted curve of fracture volume and time for the fully extended cluster shows that the increase in fracture volume became slow, with just about 1 m³ at 60−70 min. Therefore, based on the relationship between the injection fluid volume and flow rate, 53−62% of the total fluid volume is designed for diversion, and the number of plugging balls is about half of the number of perforations in the stage.

4. FIELD TESTS

4.1. Test Overview. In order to explore and evaluate the adaptability of high-efficiency network fracturing technology in the Luzhou block, two rounds of field test were conducted. The first round test was to demonstrate the adaptability of this technology in the Luzhou block, and two wells were stimulated. The second round test was designed with three wells to optimize proppant injection intensity and cluster spacing, improving well production.

According to the plan of two rounds of the field test, a total of five wells have been stimulated in the Luzhou block, and the cumulative test production was 122.5 × 10⁴ m³/d. In the first round, the average proppant injection intensity and cluster spacing were 2 t/m and 13 m, respectively, and the average test production was 17.4 × 10⁴ m³/d. In the second round, the average of proppant injection intensity increased to 2.4 t/m, the average cluster spacing was shortened to 9 m, and the average test production was 28.6 × 10⁴ m³/d, which had a 64% increase over the first round.

4.2. Typical Well Analysis. The Well L8 is a horizontal well located in the south wing of the Luoguanshan structure of the Luzhou block. The horizontal section of this well is mainly drilled at the bottom of the Longmaxi Formation, and the vertical depth is 3835 m. Based on the logging interpretation, the drilled formation belongs to class I formation, and the natural fractures are well developed in the horizontal section, which are mainly at a large angle to the wellbore. Specific formation parameters are shown in Table 3.

The fracturing technology of short-cluster spacing + high proppant amount + variable viscosity slickwater + diversion is adopted in this well. The cluster spacing is about 8 m, the flow rate is 16 m³/min, and the proppant injection intensity is 2.32 t/m. During hydraulic fracturing, 19 mm plugging balls were thrown when about 55% of the total fluid volume was injected. Figure 6 shows the typical fracturing curve of Well L8. After diversion, the pressure increased by 8 MPa, meaning that the clusters that were opened were blocked temporarily.

Table 3. Main Formation Parameters of Well L8

| parameters                     | value |
|-------------------------------|-------|
| organic carbon content, %     | 3.5   |
| porosity, %                   | 4.2   |
| gas content, m³/t             | 4.7   |
| brittle mineral content, %    | 72.6  |
| Young’s modulus, GPa          | 42    |
| Poisson’s ratio               | 0.23  |
| horizontal stress difference, MPa | 14   |

The diversion of Well L8 was analyzed by the distribution of microseismic event points (Figure 7). A total of 24 event points were monitored before diversion, which were mainly concentrated near some perforating clusters. After diversion, 66 event points were monitored, and there were event points in the vicinity of all perforating clusters, which meant that the diversion had a good effectiveness, improved the efficiency of the perforating cluster, and was conducive to the formation of complex fractures. Meanwhile, according to the results of the microseismic interpretation of Well L8, the SRV of each stage in layer 1 and layer 2 of the Sub-Longmaxi One Formation enlarges with the increase in the proppant injection intensity, as shown in Figure 8. Therefore, improving proppant injection intensity is beneficial to the effective propping of fractures and enlarging SRV.

5. CONCLUSIONS

(1) Based on large-scale true triaxial experiments for shale hydraulic fracturing, the hydraulic fractures are captured by...
natural fractures and are easy to extend along them under the condition of high horizontal stress difference, but it is difficult to form fracture networks.

(2) In the deep shale reservoir of the Luzhou block, natural fractures are well developed, and the in situ stress and horizontal stress difference are high. It is necessary to shorten cluster spacing by multi-cluster perforation, improving fracture complexity by induced stress. Meanwhile, due to the high closure pressure, proppant injection intensity should increase to improve multi-fracture conductivity. In addition, diversion technology is adopted to improve the cluster efficiency and form more flow passages.

(3) Through two rounds of field tests, the “short-cluster spacing + high proppant amount + variable viscosity slickwater + diversion” high-efficiency fracturing technology is formed. Remarkable results are obtained in the second round, and the average test production gets to 28.6 × 10⁴ m³/d, which demonstrates a 64% increase over the first round. It provides reliable technology support and study direction for further technical optimization in this block.

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Notes
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