Effect of the hydraulic fracturing-induced slippage of regional natural fracture on casing deformation in horizontal shale gas wells: A case study on the Weiyuan block

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Abstract. Casing deformation problems are widespread in the shale gas field, and the dominant natural fracture reactivation and slippage are treated as the main reasons for these casing deformations. This study establishes a mechanical model and uses the field data of Weiyuan to study the fracture slippage and the casing deformation. According to rock mechanics, the dominant natural fracture can be reactivated by the fluid injected into the fracture. A higher fluid pressure in the fracture can induce a larger slippage and a higher shear stress on the casing. The fracture slippage is not uniform along the fracture. Moreover, the maximum slippage is located at the center of the reactivation zone. The in-situ stress, friction coefficient, and angle between the fracture and the maximum in-situ stress can affect the slippage. Case studies on the casing deformation of two wells in Weiyuan have shown that the calculated slippage according to the analytical model herein is in accordance with the detected data in the field. In summary, this study provides a reliable and quick method for determining the slippage of the dominant fracture reactivation based on the distance from the fracture center.

1. Introduction
Reports show that a large number of casing deformation events occur in shale gas wells in China. In the Weiyuan and Changning shale gas fields, the casing deformations during hydraulic fracturing operations have seriously affected the safe and efficient exploitation of shale gas \cite{1, 2}. Casing deformation events occur in 36 out of 141 shale gas wells in the Changning shale gas field, and the number of points, where a casing deformation occurs, reaches 48. In the Fuling shale gas field, casing deformations occur in eight shale gas wells, which have resulted in an abandonment of 66 fracturing sections. Different from the latter, the casing deformation in the Weiyuan–Rongxian shale gas field occurs in five out of six horizontal wells \cite{3}. A large number of casing deformation problems also exist in shale gas fields in Canada and USA \cite{4, 5}.

Casing deformation problems seriously affect shale gas exploitation; hence, researchers and engineers have paid much attention to this topic. The periodic temperature stress during hydraulic fracturing treatment has been initially considered as the main reason for the casing deformation. Sugden and Tian
pointed out that in the section with a poor cementing quality, the temperature stress generated by the periodic-change temperature during the fracturing process can reduce the burst strength [2, 6]. However, no burst failure happened in the casing in the field; instead, a decrease in the casing inner diameter ended as the main form of casing deformation. Yin et al. considered that the expansion of the confined fluid in the annulus caused the casing collapse during the hydraulic fracturing process [7]. The calculated results showed that the tensile and extrusion strengths can be 23% and 20% respectively, when reduced by the temperature stress [8, 9]. The unsymmetrical expansion of the hydraulic fractures can cause the unsymmetrical deformation of the shale reservoir, thereby leading to the unsymmetrical loads along the casing and the occurrence of an S-type casing deformation [10, 11].

Like cement deficiency or casing eccentricity, the cementing quality is also considered when analyzing the reasons for the casing deformation in horizontal shale gas wells. Jiang showed that the cement efficiency induced a greater effect on the casing deformation than the casing eccentricity [12]. In addition, temperature and fluid pressure are considered in studying the effect of cement deficiency on the casing deformation [13, 14]. Liu et al. treated cement deficiency as a local load acting on the casing and calculated the stress and strength of the casing in local loads [15]. The shear deformation of the casing caused by fault slip or nature fracture is attracting increasing attention [16, 17]. Fault reactivation and slippage are considered as the main reasons for the casing deformation [18, 19]. However, the detected results showed that few faults existed in the Weirong shale gas field. Hence, only the natural fracture reactivation caused the casing deformation.

In this study, the reactivation and slippage of the natural fracture is considered as the main reason for the shear deformation of the casing. The conditions for the natural fracture reactivation are established herein to judge the possibility of the fracture reactivation. Most importantly, an analytical model is established to calculate the natural fracture slippage when the reactivated area is located at the fracture center. The factors affecting the fracture reactivation and slippage are discussed. Furthermore, the calculation method for slippage is used in the field. The proposed method for calculating the natural fracture slippage provides significant reference values for reducing the casing deformation in shale gas wells.

2. Condition and types of dominant natural fracture reactivation
Most casing deformation problems occur at the horizontal section of a well. According to the multi-arm test results (Figure 1), shear deformation is the main type of casing deformation, which is most probably caused by the slippage of the formation rock. Some researchers have claimed fault slip in the shale formation as the main reason for the casing shear deformation. However, geological analysis results have shown that only a few faults exist in the formation and not at every casing deformation point. Hence, the reactivation and slippage of large dominant natural fractures are considered as the main reasons for the casing deformation in this area. Figure 2 illustrates fracture reactivation and how it affects the casing deformation. During the hydraulic fracturing process, the fracturing fluid is injected into the nature fracture. The nature fracture is then reactivated.
2.1 Condition of the natural fracture reactivation

Figure 3 depicts that during the hydraulic fracturing process, high-pressure fluid flows into the natural fracture, and the varied fluid pressure $\Delta P$ in the natural fracture increases. Consequently, the reduction of the effective normal stress on the natural fracture interfaces causes the leftward movement of Mohr’s circle. The natural fracture reactivation and slippage occur when the varied fluid pressure $\Delta P$ in the natural fracture satisfies the condition in Eq. (1).

$$\tau_p - \tau_o \leq f \cdot \Delta P$$

(1)

where, $\tau_o$ is the bonding strength on the natural fracture. Mohr’s circle continuously moves leftward with the increase of the fluid pressure $\Delta P$. The natural fracture slippage also increases after the Mohr’s circle intersects with the natural fracture slip envelope.
2.2 Types of natural fracture reactivation

Different fracture reactivation types occur because of the location, where the fluid is injected into the natural fracture (Figure 4). In the first type, the point, where the fluid is injected into the natural fracture, is near one tip of the natural fracture. When more and more fluid is injected into the natural fracture, the reactivation zone is prevented by the nearest natural fracture tip and can extend freely along the other directions of the natural fracture. In the second type, the point, where the fluid is injected into the natural fracture, is far away from the two tips. The reactivation zone can extend freely at two directions when the fluid is continuously injected into the fracture. In the third type, the natural fracture is not large enough and is entirely reactivated by the fracturing fluid.

3. Mechanical model and slippage calculation

3.1 Mechanical model

According to the field data, the reactivation zone length of the natural fracture increased as the fracturing operations progressed. Hence, in the second type (Figure 4b), the reactivation area located at the center of the fracture was treated as the main type of fracture reactivation. Moreover, the natural fracture was partially reactivated by the injected fracturing fluid because of the shear stress on the interface (Figure 4b). The area with the fracturing fluid was shorter than the reactivated zone, and the
reactivated zone was away from the two tips of the natural fracture. The reactivated zone extension was prevented when the shear stress was fully offset by the friction. The area with the fracturing fluid was shorter than the reactivated area because of friction. The fluid pressure \( P_f \) at the zone with the fracturing fluid, which was the area with length \( L_f \) from \(-c\) to \( c\), was smaller than the normal stress on the interface. The pressure should be smaller than the normal stress on interface; otherwise, the nature fracture will be opened by the fluid pressure. At the zone from \(-d\) to \(-c\) and \(c\) to \(d\), which was reactivated by the induced stress by the slippage of area with the fracturing fluid, the fluid pressure in the natural fracture was equal to the formation pressure, \( P_w \). The zone length from \(-d\) to \(-c\) and \(c\) to \(d\) can be calculated according to the boundary condition. The length of the whole reactivation area is represented by \( L_2 \).

The effective normal stress along the natural fracture in the zone from \(-c\) to \(c\) can be expressed as \( \sigma_{yy} - P_f \), while that in the zone from \(-d\) to \(-c\) and \(c\) to \(d\) can be expressed as \( \sigma_{yy} - P_w \). The relationship between the intensity of the slippage and the shear stress on the interface is shown in Eq. (2). A detailed derivation of Eq. (2) has been shown in our previous work [20].

\[
\frac{1}{\pi} \int_{-d}^{d} B_s(\xi') \frac{1}{x' - \xi'} d\xi' = -\frac{k+1}{2\mu} \left[ \sigma_{yy} + f \left( \sigma_{yy} + P_u \right) + f \left( P_f - P_w \right) \right] \left[ H(x' + c) - H(x' - c) \right] \quad (-d < x' < d) \tag{2}
\]

where, \( \xi' \) is the location along the fracture; \( B_s \) is the climb dislocation intensity along the fracture; \( k \) is the Poisson’s ratio; \( k = 3 - 4v \); \( u \) is the elastic modulus of the formation rock, MPa; \( \sigma_{yy} \) is the normal stress at the y-axis direction caused by the in-situ stress, MPa; \( \sigma_{yy} \) is the shear stress caused by the in-situ stress, MPa; \( f \) is the friction coefficient; \( P_f \) is the hydraulic pressure caused by the fracturing fluid, MPa; \( P_w \) is the pore pressure in the formation, MPa; and \( H \) is the Heaviside step function.

According to the static balance, the total shear stress at the \((-d, d)\) interval is zero, and the shear traction at the tip of the slipped zone would be equal to 0. Hence, the boundary conditions are presented in Eq. (3) as follows through the transposition:

\[
\begin{align*}
\int_{-d}^{d} & \sigma_{yy} + f \left( \sigma_{yy} + P_u \right) + f \left( P_f - P_w \right) \left[ H(x' + c) - H(x' - c) \right] dx' = 0 \\
\int_{-d}^{d} & -\frac{2u}{K+1} \left[ \frac{1}{\pi} \int_{-d}^{d} B_s(\xi') \frac{1}{x' - \xi'} d\xi' + P_u \right] \left[ 1 - H(x' + c) + H(x' - c) \right] dx' = 0
\end{align*} \tag{3}
\]

where, \( w \) is a fundamental function.

Equation (4) is used to normalize the integration range over the \([-1, 1]\) interval.

\[
s' = \frac{\xi'}{d}; \quad t' = \frac{x'}{d} \tag{4}
\]

Equation (2) can be normalized as follows according to the variables defined in Eq. (4):

\[
\frac{1}{\pi} \int_{-1}^{1} B_s(s') \frac{1}{t' - s'} ds' = -\frac{k+1}{2u} \left[ \sigma_{yy} + f \left( \sigma_{yy} + P_u \right) + f \left( P_f - P_w \right) \right] \left[ H \left( t' + \frac{c}{d} \right) - H \left( t' - \frac{c}{d} \right) \right] \quad (-1 < t' < 1) \tag{5}
\]

Equation (5) presents the integral equation for \( B_s(s') \), which is bounded at the tips when \( s' = \pm 1\). Hence, \( B_s(s') \) can be written as Eq. (6), where \( \phi(s') \) denotes the bounded functions, and \( w(s') \) represents the corresponding fundamental functions.

\[
B_s(s') = w(s') \cdot \phi(s') = \left( 1 - s'^2 \right)^{1/2} \cdot \phi(s') \tag{6}
\]

where, \( \phi(s) \) is the bounded regular function for \( B_s \). We employed the Gauss–Chebyshev numerical quadrature formulas to reduce Eq. (5). The \( n + 1 \) algebraic equations for calculating the dislocation at discrete locations along the natural fracture presented as follows:
\[
\sum_{j=1}^{n+1} (1 - s_i^2) \phi_j(s_j) = \frac{k + 1}{2n} \left[ \sigma_n + \frac{f}{P_n} \left( \sigma_j + P_j \right) \left[ \frac{H \left( t^\prime + \frac{c}{d} \right) - H \left( t^\prime - \frac{c}{d} \right) \right] \right], \quad j = 1, 2, 3, \ldots, n+1
\] 

where,
\[
s_j = \cos \left( \frac{k \pi}{n+1} \right); \quad k = 1, 2, 3, \ldots, n
\]
\[
t_j = \cos \left( \frac{(2i-1) \pi}{2n+2} \right); \quad i = 1, 2, 3, \ldots, n+1
\]

The boundary conditions in Eq. (3) can be simplified by the Gauss–Chebyshev numerical quadrature formula. We can see that \( n + 2 \) unknowns existed: \( n \phi, c, \) and \( d \). However, there are \( n + 3 \) equations, including the two boundary conditions in Eq. (3). For the calculation, we chose the \( n \) in Eq. (7) as even and ignored the equations when \( j = n/2 \). Based on this treatment, the numbers of equations and unknowns were equivalent. Equation (8) was used to determine \( c \) and \( d \). The slippage at any point along the fracture can be achieved by solving Eq. (7).

\[
\sum_{j=1}^{n+1} \left[ \sigma_n + \frac{f}{P_n} \left( \sigma_j + P_j \right) \left[ H(x^\prime + c/d) - H(x^\prime - c/d) \right] \right] = 0
\]

### 3.2 Slippage calculation

Equation (7) shows that the factors affecting the fracture slippage were the dip angle of the natural fracture, friction coefficient, in-situ stress, and fluid pressure in the fracture. In the shale formation, the Poisson’s ratio of the formation rock \( v \) was assumed to be 0.2, while the elasticity modulus \( k \) was 20 GPa. The basic data in the slippage are as follows: vertical in-situ stress: 90 MPa; maximum horizontal in-situ stress: 105 MPa; formation pressure \( P_n \): 78 MPa; length of the zone with the fracturing fluid: 50 m; fluid pressure in the natural fracture: 45 MPa; friction coefficient: 0.55; and dip angle of the natural fracture: 45°.

The slippage along the natural fracture in different friction coefficients \( f: 0.4, 0.5, 0.6, 0.7, \) and 0.8) was calculated using Eq. (7). Figure 5a depicts the slippages in different friction coefficients. The slippage along the natural fracture in different dip angles (i.e., 15°, 30°, 45°, 60°, and 75°) was calculated, and Figure 5b shows the results. We then calculated the slippage along the natural fracture in different vertical in-situ stresses (i.e., 90 MPa, 92.5 MPa, 95 MPa, 97.5 MPa, and 100 MPa). Figure 5c illustrates the results. We also calculated the slippage along the natural fracture in different maximum fluid pressures (i.e., 30 MPa, 35 MPa, 40 MPa, 45 MPa, and 50 MPa), with the results shown in Figure 5d.
The bridge plug encountered resistance at measure P according to scale of the A l pressure. The largest slippage fracture dramatically pressure can only increase of w slippage is 45° fracture. It can also reactivated zone reactivated natural fracture decreas stress can affect the normal and shear stresses; hence, the approximate scale of the casing deformation was achieved according to the well completion operations.

Well No. 1 had three casing deformation points. Figure 6 depicts the detected microseismic signals. The friction coefficient can affect the friction force on the fracture interface. The fracture reactivation in a larger friction coefficient needs a higher shear stress and a lower normal stress on the fracture interface. Figure 5a shows that the slippage of the reactivated natural fracture decreases with the increase of the distance from the center of the reactivated zone. The whole slip zone length when the friction coefficient $f = 0.45$ was 200 m, which is three times larger than that of the zone with the fracturing fluid when $f = 0.45$. The maximum slippage was 45 mm. The lower friction coefficient caused a faster increasing length of the reactivated zone. In the field, $f$ is equal to 0.55, and the reactivated zone length is 100 m.

The principal in-situ stresses in the formation rock were vertical, maximum, and minimum horizontal in-situ stresses; hence, the dip angle of the fracture can affect the normal and shear stresses along the fracture. It can also affect the fracture reactivation and slippage. Figure 5b shows that the largest slippage is 45 mm when the dip angle is equal to 45°. The dip angle has a larger effect on the slippage when the dip angle varies from 15° to 45°. The reactivated zone length non-linearly varied with the increase of the dip angle. The largest reactivated zone was 146 m when the dip angle was equal to 30°. The vertical in-situ stress can affect the normal and shear stresses on the fracture. Moreover, the fluid pressure can only affect the normal stress on the fracture. Figure 5c shows that the slippage dramatically increases with the increase of the vertical in-situ stress. The largest slippage in the reactivated zone of the fracture was 53 mm when the vertical in-situ stress was equal to 90 MPa. Figure 5d depicts that the slippage of the reactivated zone was larger when the fluid pressure in the fracture was higher. In addition, the reactivation zone length can also be increased by the higher fluid pressure. The largest slippage was 75 mm when the fluid pressure was equal to 105 MPa.

4. Case study

A large number of casing deformation events occurred in the shale gas wells. Table 1 presents in detail the two shale gas wells with the casing deformation. No measuring tool was used to detect the exact scale of the casing deformation; hence, the approximate scale of the casing deformation was achieved according to the well completion operations.

Figure 5. Natural fracture slippage in the second type: a) slippage in different friction coefficients; b) slippage in different natural fracture dip angles; c) slippage in different vertical stresses; and d) slippage in different fluid pressures
m and MD 4239 m, the 93 mm bridge plug could not pass through the resistant point, and the earlier setting of the bridge plug is taken.
Well No. 2 has two casing deformation points. Figure 6 depicts the detected microseismic signals. The 106.5 mm bridge plug encountered resistance at 4526 m and 3647 m depths. At point MD 4526 m, the 97 mm bridge plug could not pass through the resistant point, and the earlier setting of the bridge plug is taken. At point MD 3647 m, the 97 mm bridge plug could not pass through the resistant point, whereas the 91 mm bridge plug could pass through the resistant point.
Table 2 presents the approximate size of the casing deformations. Studies on the relationship between the slippage and the casing deformation have shown that the shear deformation of the casing was approximately 10–20 mm smaller than the slippage (Liu et al., 2017). Figure 7 shows the natural fracture slippage at these five points according to the proposed method. The casing did not always intersect with the center of the natural fracture (Figure 6); hence, the points, where the slippage was calculated, were not located at the center of the slippage curve (Figure 7).

Table 1. Parameters of the wells with the casing deformation during hydraulic fracturing treatments

| Well | σv (MPa) | σH (MPa) | Point | Depth (m) | dip angle | Length | P (°) | Approximate deformation | Slippage (mm) | Calculated deformation |
|------|----------|----------|-------|-----------|-----------|--------|-------|------------------------|---------------|------------------------|
| No. 1 | 90 | 105 | A | 4937 | 48 | 240 m | 78 | ε < 21.3 mm | 42 | 22–32 mm |
| B | 4423 | 32 | 180 m | 78 | 21.3 mm < ε | 38 | 18–28 mm |
| C | 4239 | 42 | 260 m | 78 | 21.3 mm < ε | 52 | 32–42 mm |
| D | 4526 | 45 | 160 m | 73 | 21.1 mm < ε | 35 | 15–25 mm |
| No. 2 | 90 | 105 | E | 3647 | 40 | 180 m | 73 | 21.1 mm < ε < 26.6 mm | 32 | 12–22 mm |

Figure 6. Detected microseismic signals at the points, where casing deformation occurs
Figure 6 shows that most of the points, where the casing intersected with the natural fracture, were not located at the center of the reactivated zone of the natural fracture, and the dip angle of the natural fracture was not in the same. The largest natural fracture slippage was on natural fracture C (Figure 7). Table 1 presents the fracture slippage at points A to E. The calculated casing deformations were much closer to the predicted casing deformations in the wells according to the operation. Although the natural fracture slippage in well No. 1 was much larger than that in well No. 2, the difference in the casing deformations between them was not that large because the point, where the casing intersected with the natural fracture, was far from the natural fracture center in well No. 1 and close to the natural fracture center in well No. 2.

5. Conclusion

The casing deformation problems during the hydraulic fracturing treatment in the shale gas wells in Sichuan, China are mainly caused by the natural fracture slippage. We established herein a semi-analytical model for calculating the natural fracture slippage. The parameters affecting the natural fracture slippage were also discussed.

The high fluid pressure in the natural fracture caused by the channeling of the hydraulic fracturing fluid significantly increases the natural fracture slippage. After a long time of hydraulic fracturing treatment, more and more fracturing fluid is injected into the natural fracture, and the reactivated zone can be increased. The natural fracture slippage ultimately increases. The most dangerous dip angle of the natural fracture is \( \theta = 30^\circ \), which causes the largest natural fracture slippage. The friction coefficient and the in-situ stress can significantly affect the slippage, but they are intrinsic parameters of the formation rock and cannot be changed. More attention should be paid on these formations with a low friction coefficient and a high in-situ stress difference.

The calculated results according to the semi-analytical method proposed herein matched the casing deformation data in the field. The casing deformation in the field significantly affected the hydraulic fracturing treatment and the efficient exploitation of the shale gas; thus, more attention should be paid to reducing the casing deformation caused by hydraulic fracturing. This will decrease the chance of the wells to intersect with the natural fracture or prevent hydraulic fracturing fluid channeling and direct injection into the natural fracture. This study provides significant reference values for reducing the casing deformation in shale gas wells.
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