Dynamic Stress Field Evolution of the Shale Oil Reservoirs: Development and Optimization of Well Patterns

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Abstract. Research on shale oil has gained considerable attention with regard to global unconventional oil exploration, which is of the strategic significance in the field of energy. Considering the characteristics of continental shale reservoirs, a three-dimensional fluid–solid coupling model of a multistage fracturing horizontal well was established based on the poroelasticity theory. The difference in stress sensitivity among different layers was also considered in this model. The evolution of pore pressure and stress field during the production process was analyzed through numerical simulation. A comparison of the planar well pattern and stereo well pattern revealed that the latter has less interwell-flow interference and smaller alteration angle of the minimum principal stress; thus, in the latter pattern, intersection with existing hydrofractures during refracturing can be avoided. It is more advantageous to refracturing in the middle of the outside horizontal section, but with increase in production time, the optimal fracturing section shrinks. Considering the maximum recovery factor and interwell interference, well-spacing optimization is recommended from 200 m to 300 m.

1. Introduction

Shale oil and gas revolution has profoundly reshaped the global energy framework. The rapid growth of unconventional oil and gas production in the United States has made it one of the largest oil exporters. By 2018, the shale oil production in the US reached $23.49 \times 10^8$ bbl, accounting for 64.7% of the total oil production [1,2]. China has abundant continental shale oil reserves, which will be important strategic resources in the future. The generalized definition of shale oil encompasses the oil and gas resources contained in tight reservoirs with low porosity and permeability and with alternate sandstone, shale, and carbonate rock interbedding [3,4].

After years of technological development in the US, numerous mature-shale-oil production technologies such as those involving desert evaluation, ultra-long horizontal wells, three-dimensional (3D) well patterns, high-density perforation, and refracturing were developed. The US now has more than 100,000 horizontal shale oil wells, and the “well factory” drilling technology has greatly reduced the costs of shale oil drilling [5]. However, in China, unlike in the US, shale oil production is still in the exploratory stage, and less drilling has been executed compared to the US. Therefore, the design of the stereo well pattern and infill well will be the first problem to be solved with regard to China's shale oil drilling and completion [6]; meanwhile, the key scientific problem for shale oil reservoir development is the dynamic evolution of the in situ stress field.
Using the mathematical model of the induced stress of the refracturing gas well, it was proved that the variation in pore pressure resulting from production can change the distribution of the stress field of the gas well and lead to reorientation of the stress field [7]; Lin et al. [8] established the 3D model of volume fracturing by combining drilling and completion data and microseismic monitoring data of shale gas wells, and reached the same conclusions. Based on the theory of porous elastic mechanics, the sensitivity parameters of an unconventional reservoir were derived [10]. Morrill et al. [9] determined the impact of stress shadow on optimizing fracturing spacing in shale gas wells, and they found that the ratio of the minimum and maximum horizontal stress is the most important parameter that determines the optimal fracture spacing. However, few studies have explored the evolution of pore pressure field and in situ stress field during production in heterogeneous shale oil reservoirs with interbedded sandstone and shale, and that have not been used for the optimization of 3D well pattern development.

At present, in deployment plans for shale oil and gas drilling, the target is mainly considered as located in a high-quality reservoir, and the influence of the vertical borehole distribution is not considered. At the same time, the initial spacing of wells is mainly based on experience and lacks scientific guidance. To study the heterogeneous characteristics of longitudinal sand-shale interbedding in continental shale oil reservoirs, a 3D physical model of reservoirs and a fluid–solid coupling mathematical model were established for multi-level fracturing horizontal wells. Through numerical simulation to study the dynamic evolution characteristics of the pore pressure and stress fields during the production process, the planar well pattern and stereo well pattern were compared, and the spacing of the well pattern was optimized, providing guidance for the initial drilling deployment for efficient development of shale oil reservoirs.

2. Mathematical Model

2.1. Fluid–solid coupling equation

The fluid–solid coupling problem involves two physical processes, namely, fluid seepage flow and solid mechanics of the rocks. During the production, the reduction in formation pore pressure caused by the production pressure differential induces the deformation of the rock skeleton. This in turn changes the stress on the rock, affecting the flow of pore fluids, and thus, changes in pore pressure. The two physical processes are coupled. Biot introduced the Biot coefficient and the effective stress in 1941 to subtly link the pore pressure and stress state of porous media [13]. The finite element method can be used to solve the stress field and the pore pressure field of fluid–solid governing equations. The principle of effective stress is as follows:

$$\sigma_{ij}' = \sigma_{ij} - \alpha \delta_{ij} p$$  \hspace{1cm} (1)

where $\sigma_{ij}'$ is the effective stress component; $\sigma_{ij}$, the total stress component; $\alpha$, the effective stress factor; $\delta_{ij}$, the Kronecker delta; and $p$, the pore pressure.

Considering solid deformation as a quasi-static process, the stress balance equation of a rock is written as follows:

$$\frac{\partial \sigma_{ij}}{\partial x_j} - \rho_b g = 0$$  \hspace{1cm} (2)

where $\rho_b$ is solid density; and $g$, the acceleration due to gravity.

Based on the linear elasticity assumption, the constitutive relationship of the solid is as shown below:

$$\sigma_{ij}' = 2G\varepsilon_{ij} + \left( K - \frac{2G}{3} \right) \delta_{ij} \varepsilon_v$$  \hspace{1cm} (3)
where $K$ and $G$ are the volume modulus and shear modulus of the rock, respectively. $\varepsilon_y$ is the solid strain component. $\varepsilon_v = \varepsilon_y$ is the solid volume strain.

According to the assumption of small deformation of elastic solids, the relationship between strain and displacement is expressed as follows:

$$
\varepsilon_y = \frac{1}{2} (u_{i,j} + u_{j,i})
$$

where $u$ is the displacement of solid.

In the finite element solution process, solid displacement is taken as the solution variable, and the stress balance equations (1) and (4) with displacement as the variable take the following form:

$$(K + 3G)u_{i,j} + Gu_{j,i} - \alpha p_j = 0$$

During deformation of the solid, the fluid flows under the combined effect of the production pressure difference and the pore deformation. For the micro-compressible fluid, the governing equation of the fluid can be expressed as follows (Wei et al, 2019):

$$
\rho_L \frac{\partial p}{\partial t} - (\alpha - \phi) \frac{\partial \varepsilon_v}{\partial t} + \nabla \cdot \left( -\rho_L \frac{k}{\mu} (\nabla p - \rho_L g) \right) = 0
$$

$$
c_i = \phi c_L + (1 - \phi) c_b
$$

Where, $\rho_L$ and $\mu$ are the density and viscosity of the fluid, respectively; $k$ and $\phi$, the permeability and porosity of the rock, respectively; and $C_L$ and $C_b$, the compressibility of fluids and solids, respectively. Further, $C_i$ is the total compressibility of the rock.

Artificial fractures are generated by fracturing in shale oil reservoirs filled with a proppant, which can be considered as porous media, and their lengths far exceed their widths. Therefore, the flow inside the artificial fractures is calculated by the averaging method, and only the viscous flow is considered inside. Then, the mass velocity in the fracture is as given below [14].

$$
J_{af} = -\frac{k_{af}}{\mu} \rho_L \nabla p
$$

The governing equation of fluid flow in the hydraulic fracture is as follows:

$$
w_{af} \left[ \frac{\partial (\rho \phi_{af})}{\partial t} + \nabla \cdot J_{af} \right] = 0
$$

where $J_{af}$ is the mass velocity in the hydraulic fracture; $k_{af}$, $w_{af}$, and $\phi_{af}$ are the permeability, width, and porosity, respectively.

Equations (5), (6), and (9) constitute the fluid–solid coupling relations comprising the governing equations of the solid, fluid in the matrix, and fluid in the fracture.

2.2. Stress sensitivity parameter estimation

Different lithology parameters have different sensitivities to stress. The deformation of pores in sandstone is the main factor influencing changes in porosity and permeability. Shale contains a large number of natural fractures. Change in the fracture state affects shale porosity and permeability. Some previous research results on the calculation of sensitivity parameters are discussed below.

Changes in porosity during production have been extensively researched [16, 17]. According to Valliappan [18], the porosity of sandstone can be expressed as follows:

$$
\phi_{ss} = \phi_{ss}^0 + \alpha_{ss} \varepsilon_{yss}
$$

where $\phi_{ss}$ is the porosity of sandstone; $\phi_{ss}^0$, the initial porosity of sandstone; $\alpha_{ss}$, the effective stress coefficient of sandstone; and $\varepsilon_{yss}$, the volume strain of sandstone.
Kozeny–Carman proposed a functional relationship between porosity and permeability.

\[ k = f \left( \frac{\phi^3}{1-\phi^2} \right) \]  

Therefore, the permeability of sandstone can be expressed as

\[ k_s = k_s^0 \left( \frac{1 - (\phi_s^0)^2}{1 - (\phi_s)^2} \times \left( \frac{\phi_s}{\phi_s^0} \right)^3 \right) \]  

where \( k_s \) is the permeability of sandstone, and \( k_s^0 \), the initial permeability of sandstone.

The traditional stress-sensitive model of shale is mainly based on experimental fitting. The change in porosity and permeability with pore pressure have generally been well described using exponential functions. Based on the theory of porous elastic mechanics, the relationship between porosity and permeability is as follows [10]:

\[ \phi_s = \phi_s^0 + (\alpha_s - \phi_s) \varepsilon_s + \left( \frac{\alpha_s - \phi_s^0}{K_s} \right) (1 - \alpha_s) \Delta p \]  
\[ k_s = k_s^0 \left( 1 + \varepsilon_s \right)^2 \]  

where \( \phi_s \) is the porosity of shale; \( \phi_s^0 \), the initial porosity of shale; \( k_s \), the permeability of shale; \( k_s^0 \), the initial permeability of shale; \( \varepsilon_s \), the volume strain of shale; \( \alpha_s \), the effective stress coefficient of shale; and \( K_s \), the volumetric strain of shale.

The permeability of a hydraulic fracture and the pressure in the fracture are expressed in an exponential form:

\[ k_{af} = k_{af}^0 e^{C_{af}(p-p_0)} \]  

where, \( k_{af}^0 \) and \( C_{af} \) are the permeability and compressibility of the hydraulic fracture, respectively.

2.3. Model verification

Two-dimensional consolidation (Mandel's problem) was selected for verifying the correctness of the fluid–solid coupling model and for comparing the simulated results with analytical solutions [19, 20]. In this study, a quarter of the classical model was adopted because of symmetry, as shown in Figure 1. The model consists of incompressible solid constituents, and it is saturated with a single-phase incompressible fluid. Force F is applied at the top, and the right boundary is in a traction-free and drained condition. Table 1 lists the model dimensions and its material properties used in this simulation.

Figure 1 shows the increase in pressure at the monitoring point. Before draining, there was an incremental pressure, and a peak was attained. The pressure curve shows good agreement with the analytical solutions of Mandel's effect. The main reason for the increase in pore pressure is that in a short period of time, under the load, the boundary drainage pressure decreases, and the solid volume contraction leads to increase in stress, resulting in an increase in the pore pressure in the area without drainage.
Figure 1. Physical model used in this study and Mandel's effect for pressure

Table 1. Simulation parameters

| Model                           | Size       | m       |
|---------------------------------|------------|---------|
| Top load (F)                    | 30         | MPa     |

Rock and fluid properties

| Porosity                        | 0.3        |        |
| Permeability                    | $1 \times 10^{-19}$ | m$^2$    |
| Fluid density                   | 1000       | kg/m$^3$|
| Fluid viscosity                 | 0.1        | mPa:s   |

Rock mechanics properties

| Elasticity modulus              | 20         | GPa     |
| Poisson’s ratio                 | 0.2        | 1       |
| Effective stress coefficient    | 0.8        | 1       |

Initial condition

| Initial pore pressure           | 3          | MPa     |

3. Analysis of the Dynamics of the Pore Pressure and Stress Fields

3.1. Model establishment

Based on the fluid–solid coupling relations, the 3D numerical simulation model of shale oil reservoirs with two layers of sandstone and shale was established (Figure 2). The model dimensions were $1800 \times 1500$ m; the thickness of the sandstone and shale layers was 50 m and 30 m, respectively. The horizontal section of the horizontal well was located in the middle, with a length of 800 m and 15 fracturing stages. The average length of the main fracture was 80 m. The average fracture height was 30 m, and the fracture spacing was 50 m. In addition, for the boundary conditions, the normal displacement of each boundary was restricted, and each boundary was a no-flow boundary. The initial pressure of the reservoir was 30 MPa, and the bottom of the well was at a constant pressure of 15 MPa for a period of time. Using free tetrahedral grids and considering the computational cost of the 3D model, about 100,000 grids were used. The more detailed reservoir parameters used in the simulation are listed in Table 2.
In order to study the dynamic changes in the production and stress field under different drilling deployments, this model was divided into two models—model I had a planar horizontal well pattern, and model II had a stereo horizontal well pattern, as shown in the Figure 3. In model I, shown in Figure 3 (a) and (b), three horizontal wells were drilled in the same lithology layers, i.e., three each in sandstone and shale. In model II, shown in Figure 3 (c) and (d), three horizontal wells were drilled in different lithological layers, with two wells in the sandstone layer and one well in the shale layer, and vice versa. The horizontal spacing between the two horizontal wells was 200 m, and the longitudinal spacing was 20 m. To simplify the simulation, the following assumptions were made:

- The reservoir is considered vertically heterogeneous, and the same lithology is an isotropic homogeneous layer.
- All horizontal well sections have identical length, irrespective of the interference of fractures during fracturing; the fracturing stage, fracture length, and height are the same.
- The stress difference between layers is less than 4 MPa (Geng, 2004), neglecting the influence of lithology on the propagation of the fractures connecting the two layers.

![Figure 3. Shale oil reservoirs model.](image-url)
Table 2. Simulation parameters

| Parameters | Values | Units | Explanation | Parameters | Value | Units | Explanation |
|------------|--------|-------|-------------|------------|-------|-------|-------------|
| $\sigma_y$ | 67     | MPa   | Overburden stress | $w_f$ | 1 | mm | Width of fracture |
| $\sigma_{H_{ss}}$ | 44     | MPa   | Maximum horizontal principal stress of sand | $\phi_{ss}$ | 0.06 | m$^3$/m$^3$ | Porosity of sandstone |
| $\sigma_{hs}$ | 40     | MPa   | Minimum horizontal principal stress of sand | $\phi_s$ | 0.04 | m$^3$/m$^3$ | Porosity of shale |
| $\sigma_{H_{s}}$ | 49     | MPa   | Maximum horizontal principal stress of shale | $\phi_{af}$ | 0.3 | m$^3$/m$^3$ | Porosity of fracture |
| $\sigma_{hs}$ | 44     | MPa   | Minimum horizontal principal stress of shale | $\alpha_{ss}$ | 0.8 | 1 | Effective stress coefficient of sandstone |
| $E_{ss}$ | 40     | GPa   | Elasticity modulus of sandstone | $\alpha_s$ | 0.75 | 1 | Effective stress coefficient of shale |
| $E_s$ | 20     | GPa   | Elasticity modulus of shale | $\rho_{ss}$ | 2000 | kg/m$^3$ | Sandstone density |
| $\nu_{ss}$ | 0.15   | 1 | Poisson’s ratio of sandstone | $\rho_s$ | 2200 | kg/m$^3$ | Shale density |
| $\nu_s$ | 0.23   | 1 | Poisson’s ratio of shale | $\rho_L$ | 900 | kg/m$^3$ | Fluid density |
| $k_{ss}$ | 0.005  | mD   | Permeability of sandstone reservoir | $\mu_L$ | 4 | mPa·s | Fluid viscosity |
| $k_s$ | 0.001  | mD   | Permeability of shale reservoir | $p_0$ | 30 | MPa | Initial pore pressure |
| $k_{af}$ | 25000  | D     | Permeability of fracture | $p_{af}$ | 15 | MPa | Borehole pressure |

3.2. Numerical simulation results

Two production schemes were proposed for shale oil reservoirs interbedded with sandstone and shale in restricted reservoirs—the planar horizontal well pattern of model I and the stereo horizontal well pattern of model II. It was assumed that the hydraulic fracture height is the same, but in 3D space, the extension of each layer is different, and the contribution of each layer to the production of horizontal wells is also different. In the production process within a certain period of time, the production, sweeping volume, and in situ stress field under different cases are different. With interference between production wells, production will also be affected; in such a case, the wells have to be shut down for refracturing. Since the direction of the horizontal minimum principal stress during production changes constantly [22], the fractures that expand during refracturing will also intersect the existing hydraulic fractures. The greater the alteration angle, the easier it is for the fractures to intersect, thereby reducing the effect of repeated fracturing. Therefore, the evolution of the stress field in the production process is based on the initial drilling design.

3.2.1 Planar horizontal well pattern of Model I

In model I, three horizontal wells were drilled each in the sandstone and shale layer. Figure 4 shows the pore pressure distributions of model I (a) and model I (b) at different production times. The pressure distribution in sandstone has a profile similar to that in shale, and the pressure drop is concentrated around the fracture zone, but the variation in sandstone is much faster because the permeability of hydraulic fractures is much greater than that of tight reservoirs and because the permeability of sandstone is greater than that of shale. Meanwhile, there is little change in the pore pressure away from the fracture zone owing to the low permeability of the tight reservoir matrix. This
prevents the pressure drop from propagating far away. With increase in production time, the area of interwell-flow disturbance expands, resulting in a rapid decrease in daily production.

![Figure 4. Pore pressure distributions in the sandstone and shale layers during production (Model I a(i), (ii), and (iii): Pore pressure in the sandstone layer section after 10, 100, and 300 days of production; Model II b(iv), (v), and (vi): Pore pressure in the shale layer section after 10, 100, and 300 days of production)](image)

The change of pore pressure caused by production can generate an induced stress field, which leads to the reorientation of the in situ stress field. Owing to the different magnitudes and directions of stress at different depths in the space, the cross sections of the sandstone and shale layers are selected. In the Figure 5, the magnitude and orientation of the minimum principal stress after 300 days of production is shown. The magnitude and direction of the principal stress in the plane can be expressed by the following formula:

\[
\sigma_{H,h} = \frac{\sigma_x + \sigma_y}{2} + \sqrt{\left(\frac{\sigma_x - \sigma_y}{2}\right)^2 + \tau_{xy}^2} \tag{16}
\]

\[
\tan \theta = -\frac{\tau_{xy}}{\sigma_{H} - \sigma_x} \tag{17}
\]

where \(\theta\) represents the angle between the minimum horizontal principal stress and the \(x\) direction.

As seen in Figure 5, the minimum principal stress in the sandstone layer near the fracture decreased by about 6 MPa, and that in the shale layer without drilling below the sandstone also decreased by 2 MPa. For model I(b), although three horizontal wells were drilled in the shale layer, and the decrease in the minimum horizontal principal stress of the sandstone layer without drilling above the shale layer was higher. The reason is that the sandstone layer has better porosity and permeability conditions than the shale layer. We can also see the effect of stress in the vertical direction.

The induced stress fields of the three wells influence each other. The intermediate wells are suppressed by the wells on both sides, the alteration angle of the minimum horizontal principal stress is smaller, while that around the fractures on the outside wells is more obvious. At the same time, the alteration of the minimum horizontal principal stress at both ends of the horizontal well segment is the largest, and the area of influence gradually increases with the production time, extending from both sides of the
horizontal well segment to the middle. The angle near the fracture of the sandstone layer is larger than that of the shale layer.

Figure 5. Magnitude and orientation of the minimum principal stress in the sandstone and shale layer sections after 300 days of production ((i) and (ii) show the minimum principal stress in the sandstone and shale layers of model I (a), respectively; (iii) and (iv) show the minimum principal stress in the sandstone and shale layers of model II (b), respectively)

For model I(a), when drilling only in the sandstone layers with high porosity and permeability, refracturing can be selected in the middle of the horizontal well section of the outside well. As the production time increases, the length of the optional fracturing section decreases. In addition, a new well can be drilled in shale layer to infill when alteration angle is small.

3.2.2 Stereo horizontal well pattern of Model II
Figure 6 presents the spatial distribution of pore pressure for model II over time. As shown in Figure 6 (i) and (ii), the pressure drop of the hydraulic fracture near two wells drilled in the sandstone layer is larger, and one well drilled in shale layer also has an effect on the sandstone layer. Therefore, the stereo well pattern can develop the remaining oil between two wells in the sandstone layer. However, owing to the vertical distance, the pressure drop is delayed. A similar phenomenon is observed in Figure 6 (iii) and (iv). The development effect of model II (d) is relatively poor.
Figure 6. Distributions of pore pressure in the sandstone and shale layers during production (Model II c(i) and (ii): Pore pressure in the sandstone and shale layer section after 300 days of production, respectively; Model II d(iii) and (iv): Pore pressure in the sandstone and shale layer section after 300 days of production, respectively)

Similarly, we see the distributions of the magnitude and direction of the minimum horizontal principal stress under the 3D well pattern; it decreases by 6 MPa around the hydraulic fractures in the sandstone layer, while that in shale decreases to a less extent, with a maximum decrease of 3 MPa, as shown in Figure 7. Taking model II (c) as an example, it is seen that the stress-affected areas of horizontal wells in different lithological layers interfere with each other. The sandstone layer undergoes a change in the stress-angle within 200 m from the horizontal section of the outside well, and there is no obvious stress turn in the symmetrical middle position of the wells on both sides. In Figure 7(ii), the alteration angle of the minimum horizontal principal stress at the shale layer below is not clear; this is consistent with the single-layer rule mentioned earlier.
Figure 7. Magnitude and orientation of the minimum principal stress in the sandstone and shale layer sections after 300 days of production ((i) and (ii), respectively, show the minimum principal stress in sandstone and shale layer sections of model II (c); (iii) and (iv), respectively, show the minimum principal stress in the sandstone and shale layer sections of model II (d))

3.2.3 Comparative analysis

The production of each layer per unit thickness was calculated. Figure 8(i) shows the production contributions of different rock formations and the total production for 300 days under different well deployments. Models (a), (c), and (d) have significantly higher yields than that of (b). The main production comes from the sandstone layer. The total production of model (a) is slightly larger than that of (c) and (d). The main reason is that sandstone has higher porosity and permeability than shale, and the reservoir is of high quality. Meanwhile, comparing Figure 4 and Figure 6 shows that when the well spacing in a layer is small, as the production time increases, the interwell interference will be more severe. The regional reservoirs are not developed reasonably, and the shale production capacity is abandoned. Figure 8(ii) shows the decay curve of daily production. The production decline of curve b occurs earlier than in the other models, and the decline is relatively large. The other models do not differ much. In summary, model (c) development is more reasonable.

The changes of pore pressure field and stress field under the two schemes were analyzed. For identical well spacing, the interwell interference of 3D development is smaller, and the remaining oil between the two wells can be produced by “v” shaped drilling. If the production declines later, reservoirs in the same area have the fewest wells to achieve the best development effect, and refracturing may be considered to avoid drilling new wells. Comparing the changes in the stress field in Figure 5 and Figure 7, in model I (a), the change in the direction of stress occurs within 300 m from the horizontal section of the outside well, and the maximum alteration angle reaches about 35°. Model II (c) has a smaller stress alteration angle and magnitude than model I (a). When refracturing, fracturing in the horizontal wells of the shale layer or in the middle position of the horizontal section of the outside wells on the sandstone layer is recommended. As the production time increases, the optimal fracturing interval becomes shorter.
Figure 8. Comparison of the cumulative and daily production index per meter for different well patterns

3.3. Stereo horizontal well-spacing optimization

The initial drilling deployment scheme for model II (c) in the well pattern is better, and hence, this model was adopted to optimize the well spacing of the 3D well pattern. For small well spacing, the interwell fractures are seriously disturbed; when the well spacing is large, the interwell area cannot be effectively developed. Hence, a reasonable well spacing should be selected. The stereo horizontal well pattern includes transverse and vertical well spacing. Because vertical well spacing is related to fracture propagation, a fixed value of 20 m is assumed within the limited reservoir range to optimize the transverse well spacing.

Figure 9 shows the pressure drop distribution at different lateral well spacings for 600 days of production. In the figure, color variation of pore pressure around the wellbore indicates that the pressure drop in the fracture area of the sandstone layer is significantly greater than that in the shale layer. The statistical analysis of the reservoir area showed that the exploited range of reserves under different well spacings was $4.382 \times 10^7$, $5.739 \times 10^7$, $7.056 \times 10^7$, and $7.982 \times 10^7$ m$^3$. The pressure drop range of D was relatively large mainly because of the lack of interference between adjacent wells during 600 days of production.
Figure 9. Pressure drop zones of different well spacings within 600 days of production ((A), (B), (C), and (D) represent horizontal spacing of 100, 200, 300, and 400 m, respectively)

Figure 10 shows the change in the stress field in the sandstone layer under different well spacing. The stress reduction range is clear near the horizontal wells in the sandstone layer. The symmetrical middle area is mainly affected by the horizontal wells in the shale layer. The reorientation of the minimum horizontal principal stress is mainly concentrated on both sides of the outside well, and the middle position is disturbed by the symmetrical wells on both sides. No steering angle was observed. As the well spacing increased, the stress interference between wells decreased, and the reorientation of stress occurred in the middle area, as shown in Figure 10(D). In the initial given well spacing, such as B and C, the stress reduction in the middle area was small, and the alteration angle was relatively small. As the production time increased, the stress field around the outside wells started changing. Refracturing in the horizontal well of the shale layer is recommended because it is not easy to cross the fracture.

Figure 11 shows that the cumulative total production varies with time for different well spacing. A well spacing of 100 m is subject to severe interwell interference, and the production is relatively low. The production for other well spacing is not much different. It is recommended that the well spacing is set 200–300 m.
4. Conclusion and Summary

In this study, a 3D fluid–solid coupling model for multi-level fracturing horizontal wells was established for continental shale oil reservoirs. Through numerical simulation to study the dynamic evolution characteristics of the pore pressure and stress fields during the production process, the planar and stereo well patterns were compared, and the spacing of the well pattern was optimized. The following conclusions can be drawn from the above results:

- The pore and permeability conditions of sandstone is better than that of shale. Hence, the pressure drop, stress change, and the alteration angle in the sandstone layer are greater than that in the shale layer.
- Considering the initial drilling deployment, for identical well spacing, the interwell interference of the stereo horizontal well pattern is small, and the alteration angle of stress is also relatively small. The location of refracturing should be selected in the middle of the horizontal wells on both sides.
- Considering the stress interference and the cumulative total production, it is recommended that the spacing between wells be 200–300 m.

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