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Flowback Characteristics Analysis and Rational Strategy Optimization for Tight Oil Fractured Horizontal Well Pattern in Mahu Sag

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Abstract: With the deep development of tight reservoir in Mahu Sag, the trend of rising water cut during flowback concerns engineers, and its control mechanism is not yet clear. For this purpose, the integrated numerical model of horizontal well pattern from fracturing to production was established, and its applicability has been demonstrated. Then the flowback performance from child wells to parent wells and single well to well pattern was simulated, and the optimization method of reasonable flowback strategy was discussed. The results show that the formation pressure coefficient decreases as well patterns were put into production year by year, so that the seepage driving force of the matrix is weakened. The pressure-sensitive reservoir is also accompanied by the decrease of permeability, resulting in the increase of seepage resistance, which is the key factor causing the prolongation of flowback period. With the synchronous fracturing mode of well patterns, the stimulated reservoir volume (SRV) is greatly increased compared with that of single well, which improves the reservoir recovery. However, when the well spacing is less than 200 m, well interference is easy to occur, resulting in the rapid entry and outflow of fracturing fluid, and the increased water cut during flowback. Additionally, the well patterns in target reservoir should adopt a drawdown management after fracturing, with an aggressive flowback in the early stage and a slow flowback in the middle and late stage. With pressure depletion in different development stages, the pressure drop rate should be further slowed down to ensure stable liquid supply from matrix. This research can provide a theoretical guidance for optimizing the flowback strategy of tight oil wells in Mahu sag.

Keywords: tight oil; horizontal well pattern; parent and child wells; flowback characteristics; strategy optimization; numerical simulation

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1. Introduction

Mahu oilfield is an unconventional tight conglomerate reservoir, which has been developed on a large scale by means of the multi-stage fracturing with horizontal well [1]. After years of exploration, the fracturing mode has changed from single well scattered treatment to the zipper fracturing of small space well pattern, greatly improving the construction efficiency [2]. The flowback process is an important step after the completion of fracturing, and flowback efficiency is a highly concerned indicator, which refers to the ratio of the cumulative production of fracturing fluid to the total amount of that injected. Compared to conventional reservoirs, the flowback efficiency of tight reservoirs is generally lower. However, with the increase of well pattern density, the water cut and flowback efficiency of infill wells are on the rise, and the flowback period of fracturing fluid is significantly prolonged. Field data show that the time of oil onset after fracturing is late, and some wells have long-term high water cut, which has seriously affected normal production. Therefore, it is urgent to carry out flowback characteristics analysis to clarify the control mechanism behind the increasing water production and water cut trend, so as to provide guidance for the optimization of flowback strategy in Mahu conglomerate reservoir.

Currently, hydraulic fracturing is the main technology of economic and effective development of unconventional oil and gas reservoirs. Due to the large amount of fracturing fluid entering underground, the fluids still flow out of the wellbore with oil and gas for a long time, even after the flowback [3]. Therefore, operators are concerned with the flowback performance and its impact on productivity. Extensive studies have been conducted, which can be mainly divided into the following two aspects according to the distribution of fracturing fluid: (1) Due to capillary imbibition [4], osmotic pressure [5] and clay hydration [6] in matrix system, fracturing fluid is difficult to flow back after invading the micro and nano pores of the reservoir under the above single or multiple mechanisms, resulting in lower flowback rate. Some scholars believe that fracturing fluid retention underground is conducive to productivity, as the fluids will displace more oil and gas into fractures when they infiltrate the matrix [7,8]. However, there are also views that the retention fluids will form a filtration trap near hydraulic fractures, reducing oil phase permeability, and not conducive to long-term productivity [9,10]. (2) Closure behavior [11] and gravity segregation [12] in fracture system are the key factors. When the fracture propagation patterns are relatively simple, fracture closure is the main driving mechanics of fracturing fluid flowback [13]. In this case, the flowback efficiency is high and the oil breakthrough time is late. On the contrary, the contact area between fracture and matrix is greatly increased when the fracture propagation patterns are complex [14,15], and the water cut decreases rapidly, resulting in high initial production. In addition, part of the fracturing fluid accumulates near the bottom of the vertical planar fracture due to gravity segregation, which reduces the flowback efficiency [16]. However, most of the above studies take the single well or single fracture model as the analysis object [17,18], without considering the dynamic change of reservoir conditions between parent and child wells. Meanwhile, there is also little attention paid to the seepage characteristics of synchronous flowback under the small space well pattern. Accordingly, it is difficult to clarify the impacts of geotechnical engineering factors on the flowback process, which will inevitably affect the rational flowback strategy design of fractured horizontal wells.

Uddin et al. [19] and Samuel et al. [20] listed the evolution of fracturing techniques in Permian Basin over the decade. From the initial single-cluster fracturing treatment to the current multi-cluster completion & multi-well synchronous fracturing, the amount of fracturing fluid had skyrocketed and the overall water cut has been on the rise. The flowback strategy also changed from the relatively slow mode to a more aggressive mode. Xie et al. [21] showed that fast flowback could effectively improve oil production for some tight oil wells. Although water cut increased significantly, it had little impact on long-term productivity. To avoid rapid pressure depletion, the slow flowback strategy is generally adopted for Mahu oilfield [22], while the differences between well patterns become increasingly prominent under the uniform management. Based on geoengineering approach, this paper establishes an integrated numerical model of horizontal well pattern from fracturing to production, quantitatively studies the differences of flowback performance between parent and child wells, as well as different spacing wells. Then, a reasonable flowback strategy for well patterns is optimized in order to improve the recovery factor of Mahu oilfield.

2. Methodology

2.1. Model Description

2.1.1. Assumptions

The key assumptions for building this geotechnical engineering model are shown here. (1) This workflow includes two simulation processes of fracturing and production. Fracturing is a process of fracture propagation based on geomechanical model. Production is an oil-water two-phase flow process based on the complex fracture model depicted by the former. (2) This case focuses on flowback and production performances during the spontaneous production period. Considering that the formation pressure is always above the saturation pressure, there is isothermal flow of oil and water in hydraulic fractures and reservoir matrix. (3) Reservoir fluids is slightly compressible. (4) Stress sensitivity of matrix system and closure behavior of fracture system are considered. (5) The capillary imbibition effect is ignored in fractures and considered in tight matrix, based on experimental data available.

2.1.2. Governing Equations

(1) Fracture propagation mathematical model

In this model, all fractures are assumed to be vertical fractures and the fracturing fluid is a power-law fluid flowing laminar within fracture system, which satisfies Poiseuille's formula, local continuity equation and global mass conservation equation [23]:

$$\begin{cases} B = B(p, R_s) \\ \mu = \mu(p, R_s) \end{cases} \tag{1}$$

$$\alpha_0 = \frac{2K'}{\phi(n')^{n'}}\left(\frac{4n'+2}{n'}\right)^{n'}; \phi(n') = \frac{1}{H_{fL}}\int_{H_{fL}}\left(\frac{w(z)}{\overline{w}}\right)^{\frac{2n'+1}{n'}} dz \tag{2}$$

$$\frac{\partial q}{\partial s} + \frac{\partial\left(H_{fL}\overline{w}\right)}{\partial t} + q_L = 0 \tag{3}$$

$$\int_0^t Q(t)dt = \int_0^{L(t)} h\overline{w}ds + \int_{H_L}\int_0^{L(t)}\int_0^t q_L dt ds dh_L \tag{4}$$

where p is fluid pressure; s is coordinate value of any point in fracture; $\overline{w}$ is mean fracture width; q is volume fluid rate; H_{fL} is fluid height in fracture; z is depth at coordinate s; $w(z)$ is fracture width under depth z; n', K' are power law index and consistency coefficient, respectively; t is time; q_L is filtration rate of fracturing fluid; $Q(t)$ is pumping rate at time t; h is fracture height; $L(t)$ is total length of all extended fractures at time t.

It can be seen from Equations (1) and (3) that the distribution of fluid pressure and rate in fractures is a function of fracture width. However, when the fluid pressure on the boundary surface of rock mass changes, the rock mass will deform and the fracture width will change accordingly. Therefore, in the elastic equation of rock mass, the fracture width is also a function of the fluid pressure in fractures [24]. In this paper, the fracture width calculation method in the pseudo-three-dimensional fracture propagation model is used, and the stress-strain is assumed to occur only in the vertical profile. Since the actual hydraulic fractures usually extend vertically through multiple layers, and the horizontal stress and fluid pressure vary in each vertical layer, the analytical equation established by Mack [25] is used to calculate the vertical fracture width profile as follow:

$$K_{Iu} = \sqrt{\frac{\pi h}{2}}\left[p_{cp} - \sigma_n + \rho_f g\left(h_{cp} - \frac{3}{4}h\right)\right] + \sqrt{\frac{2}{\pi h}}\sum_{i=1}^{n-1}(\sigma_{i+1} - \sigma_i)\left[\frac{h}{2}\arccos\left(\frac{h-2h_i}{h}\right) - \sqrt{h_i(h-h_i)}\right] \tag{5}$$

$$K_{Il} = \sqrt{\frac{\pi h}{2}}\left[p_{cp} - \sigma_n + \rho_f g\left(h_{cp} - \frac{h}{4}\right)\right] + \sqrt{\frac{2}{\pi h}}\sum_{i=1}^{n-1}(\sigma_{i+1} - \sigma_i)\left[\frac{h}{2}\arccos\left(\frac{h-2h_i}{h}\right) + \sqrt{h_i(h-h_i)}\right] \tag{6}$$

$$w(z) = \frac{4}{E'}\left[p_{cp} - \sigma_n + \rho_f g(h_{cp} - z)\right]\sqrt{z(h-z)} + \frac{4}{\pi E\prime}\sum_{i=1}^{n-1}(\sigma_{i+1} - \sigma_i)\begin{bmatrix} (h_i - z)\cosh^{-1}\frac{z\left(\frac{h-2h_i}{h}\right)+h_i}{|z-h_i|} \\ +\sqrt{z(h-z)}\arccos\left(\frac{h-2h_i}{h}\right) \end{bmatrix} \tag{7}$$

where K_{Iu}, K_{Il} are stress intensity factors at the top and bottom of vertical fractures, respectively; h_{cp} is the height from the perforation to the bottom of the fracture; p_{cp} is fluid pressure at depth h_{cp}; σ_n is normal stress; ρ_f is fluid density; i is sequence number of strata from top to bottom of the fracture; h_i is height from the top of layer i to the bottom of the fracture; E' is plane-strain elastic modulus.

Equations (5) and (6) are also propagation criteria for fracture height direction. Then, Equations (1)~(7) constitute the mathematical model of fracture propagation based on UFM model as a whole.

(2) Fluid flow mathematical model

The black oil model of a single porous medium is adopted to investigate the seepage process of fracturing fluid injection and two-phase fluid production. The basic governing equations are shown as follows:

$$\frac{\partial}{\partial t}(\frac{\phi S_o}{B_o}) - \nabla[\frac{KK_{ro}}{\mu_o B_o}(\nabla p_o - \gamma_o \nabla Z)] - q_{osc} = 0 \tag{8}$$

$$\frac{\partial}{\partial t}(\frac{\phi S_w}{B_w}) - \nabla[\frac{KK_{rw}}{\mu_w B_w}(\nabla p_w - \gamma_w \nabla Z)] - q_{wsc} = 0 \tag{9}$$

where S_o, S_w are oil and water phase saturation, respectively; B is formation volume factor; ϕ is the effective porosity; μ is viscosity; K is absolute permeability; K_r is relative permeability; γ is fluid density under formation conditions; Z is grid center depth; q_{sc} is the sink or source term of fluid.

Equations (8) and (9) are differential seepage equations of oil and water phases respectively, and include additional equations of state, saturation and capillary force as follows:

$$\begin{cases} B = B(p, R_s) \\ \mu = \mu(p, R_s) \end{cases} \tag{10}$$

$$S_o + S_w = 1 \tag{11}$$

$$p_{cow} = p_o - p_w = p_c(S_w) \tag{12}$$

2.1.3. Integrated Workflow

Currently, it is difficult to implement the full coupling of geomechanics and fluid flow mechanism at reservoir scale, an integrated workflow was carried out on the basis of the existing geotechnical engineering software platform according to the above assumptions. Figure 1 shows the detailed simulation flow: (1) The UFM model is adopted to characterize the complex fracture networks. Firstly, a geomechanical model is established according to the geological and logging data. Then the fracture propagation process is simulated according to the actual pumping schedule, and finally the simulated complex fractures are converted into unstructured grid model. (2) The commercial reservoir simulator is used to simulate the flowback and spontaneous production process. Reservoir and fluid physical parameters and stress sensitivity curve are first set for the unstructured grid model. Then, the fracturing fluid injection and shut-in process are simulated according to the actual total fracturing fluid volume, pumping rate and shut-in time, accurately depicting pressure and saturation distribution of stimulated reservoir. Finally, the well schedule is set up and the history matching and productivity forecasting are carried out.

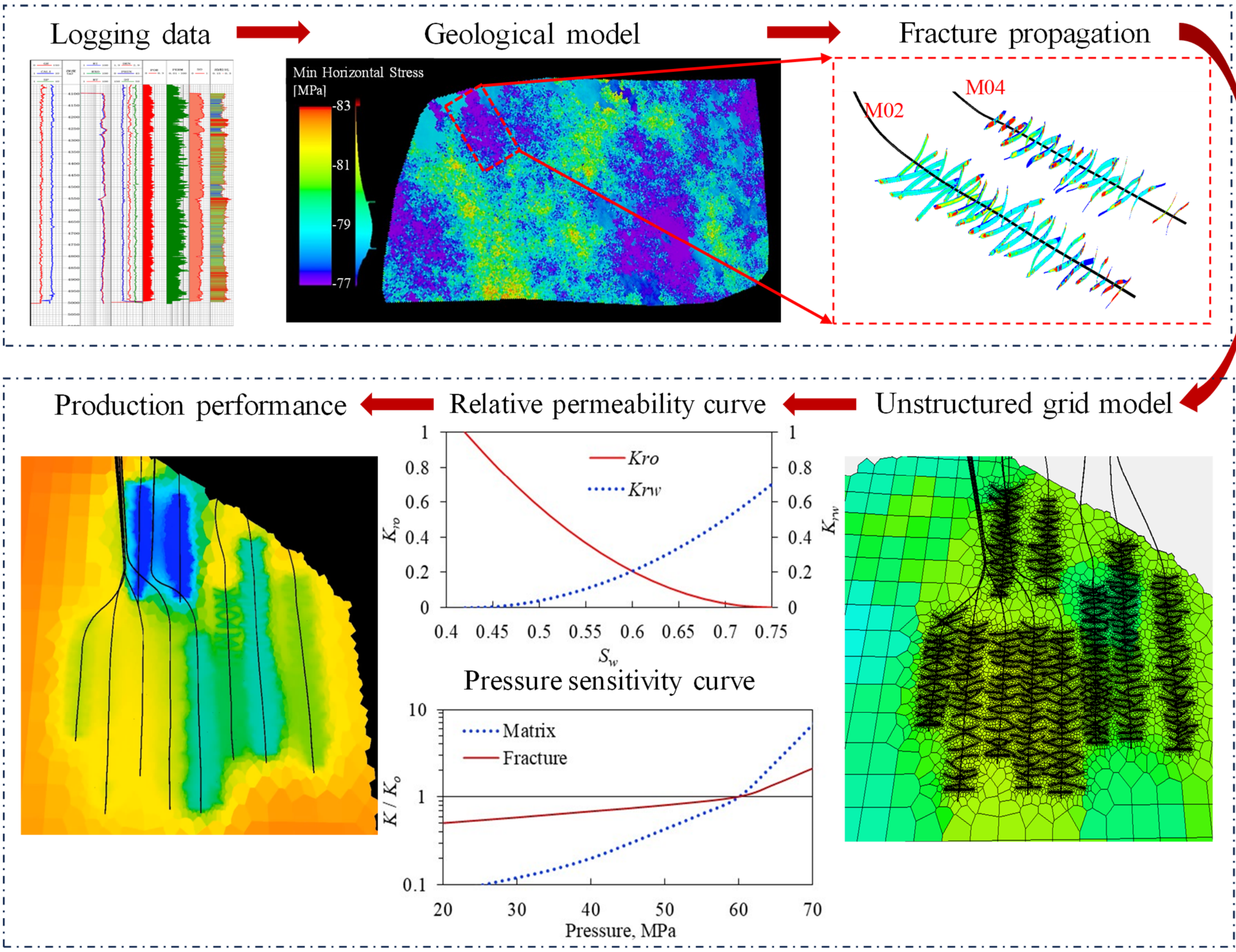


Figure 1. Integrated simulation workflow from fracturing to production for horizontal well pattern.

2.2. Model Validation

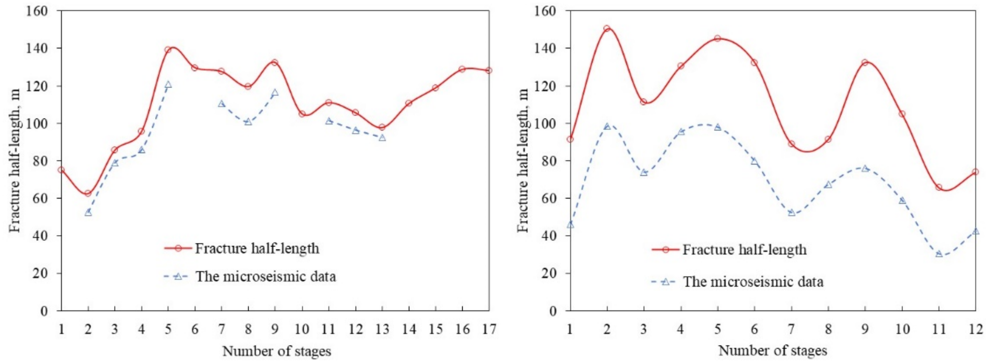
The applicability of two simulation processes of fracturing and production is verified respectively.

(1) Complex fractures characterization

Compared with orthogonal or discrete fracture model, fracture propagation simulation based on actual geological data and engineering parameters is the most direct way to characterize complex fractures. Figure 2 shows the comparison of simulation results with microseismic monitoring in Wells M02 and M04. Due to differences in the principles and accuracy of explanation, the average half-lengths of each well interpreted by microseismic monitoring are 78 m and 103 m, which are lower than the values simulated by this model as showed in Figure 2. However, the variation trend in each fracturing stage is consistent with the microseismic monitoring results, indicating that the simulated fracture size can reflect the actual fracturing effect.

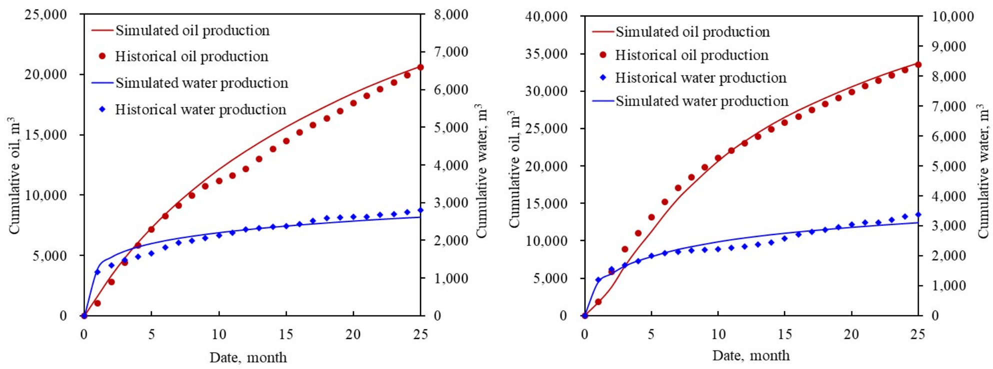
(2) History matching in spontaneous production stage

The pressure data in spontaneous production history is input to simulate the constrain pressure production for Wells M02 and M04. By comparing the historical water and oil production data with the simulated data, the final fitting result is shown in Figure 3. The overall error meets the engineering accuracy requirements and is in line with the field production performance. However, it can be seen that the fitting effect in the early stage of flowback is relatively poor. Since the choke size is frequently switched at initial, higher frequency data is required to capture the flowback performance, so as to achieve a more ideal fitting.



(**a**) Well M02 (**b**) Well M04

Figure 2. Comparison of simulation results with microseismic interpretation.



(**a**) Well M02 (**b**) Well M04

Figure 3. History matching curves in spontaneous production stage.

3. Analysis of Flowback Characteristics

With the continuous development of Mahu oilfield, the well spacing density rises year by year, and the fracturing efficiency is also improving. However, this is accompanied with the increasing water cut, the impact of which on oil recovery is unclear. It is necessary to explore the mechanism behind the variation of flowback performance in fractured horizontal wells.

3.1. Between Parent and Child Wells

Taking ten fractured horizontal wells as an example, their fracturing parameters are similar, as shown in Table 1. The production time of Wells M02 and M04 has been separated by 5 months, and the other well patterns are fractured and put into production at the same time in each year. Based on history matching results, Figure 4 shows the variation of formation pressure over time in the whole area. It can be found that under depleting development mode, the formation pressure keeps decreasing with the increase of production time. Figure 5a shows the variation of the difference between the cumulative fluid output (the amount of oil and water produced by all wells) and injection (the amount of fracturing fluid pumped during fracturing) over time. It should be noted that after about 10 months of production in the first pair of Wells M02 and M04, the produced fluid volume is equal to the injected fluid volume, and there was no reservoir fluid deficit. However, after the second and third pair of well patterns are put into production, reservoir fluid depletion began to accelerate, from -4.4×10^3 t to 11.8×10^3 t to 48.1×10^3 t. The variation trend of formation pressure coefficient in Figure 5b corresponds to the degree of fluid depletion.

When the second pair of Wells M09 and M10 begins to put into production, the formation pressure coefficient remained at the original level of 1.66 because the reservoir is not yet in deficit. And after that, the pressure coefficient decreases to 1.61 and 1.52 year by year. The reasons for this can be summarized as follows: (1) compared to parent wells, the natural energy of child wells decreases with the depletion of pressure, which weakens the supply of matrix, resulting in an increase in initial water cut. (2) Due to the stress sensitivity of reservoir, the matrix permeability also greatly decreases with pressure depletion, which increases flow resistance, further leading to the decrease of oil production.

Table 1. Basic well and fracturing information of horizontal well pattern.

Starting Date of Production (Month, Year)	Well Name	Number of Stages	Number of Clusters	Length of Horizontal Interval (m)	Injected Volume per Unit Length (m^3/m)	Proppant Volume per Unit Length (m^3/m)
Nov., 2016	M02	17	33	994	18.0	1.1
Jun., 2016	M04	12	22	938	15.1	0.9
Apr., 2017	M09	16	31	1203	16.2	1.1
	M10	21	41	1200	18.0	1.1
Apr., 2018	M11	22	43	1603	17.0	1.0
	M12	20	39	1400	17.3	1.0
Apr., 2019	M05	13	25	904	16.2	1.0
	M06	15	29	1212	18.5	1.0
	M07	11	21	977	16.4	1.0
	M08	17	33	1178	17.2	1.0

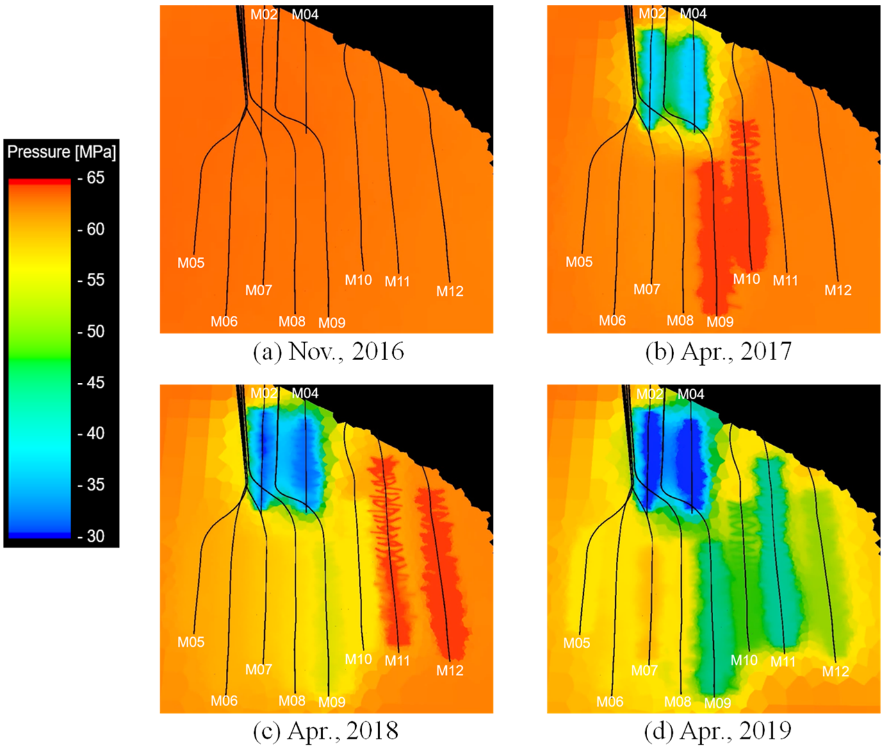


Figure 4. Variation of formation pressure over time in the whole area.

Figure 6 shows the curve of oil produced and water retained year by year. On the one hand, underground oil reserves continue to decrease with production; on the other hand, due to the capillary imbibition of tight reservoirs, the flowback efficiency of whole well patterns is generally low, and the amount of retained fracturing fluid increases with the increase of the number of wells put into production. Whereas, although the impact of reservoir saturation evolution is minor, the water cut of child wells increases year by year inevitably.

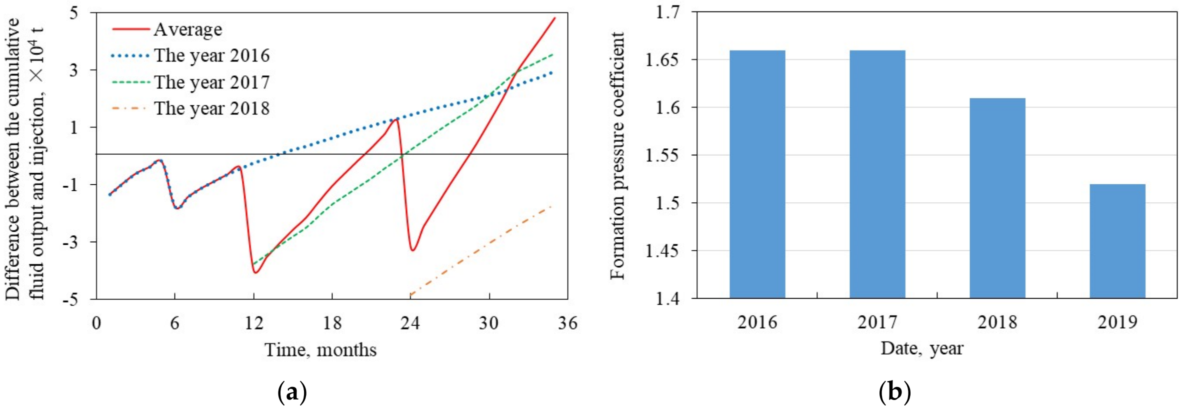


Figure 5. (**a**) Difference between the cumulative fluid output and injection over time. (**b**) Formation pressure coefficient over time.

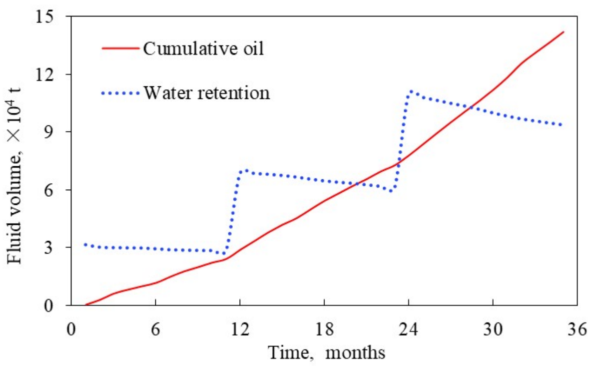


Figure 6. Curve of oil produced and water retained over time.

3.2. Different Spacing Wells

In order to reduce the uncertainty such as reservoir heterogeneity and interference between parent and child wells, a sub-model (1200 m in parallel horizontal interval direction, 600 m in vertical horizontal interval direction, and 30 m in reservoir thickness) is extracted with Well M04 as the center. The basic parameters of wells refer to Well M04 in Table 1. Four cases are simulated to investigate the impact of well spacing on flowback performance and well productivity, as follows: Case 1 (single well), Case 2 (two well pattern with 300 m spacing), Case 3 (three well pattern with 200 m spacing) and Case 4 (four well pattern with 150 m spacing). The result of fracture configuration for different cases is shown in Figure 7. It can be seen that the overall SRV of well pattern increases obviously with the decrease of well spacing. However, too small well spacing is also easy to cause "fracture hit". For example, when the well spacing drops to 150 m, there is a significant phenomenon of re-fracturing in local areas between wells, which might pose a serious waste for fracturing materials.

The spontaneous production continues until bottom-hole pressure drops to 35.2 MPa (near saturation pressure), and the results of water cut and oil production are shown in Figure 8. It can be found that the average water cut increases with the increase of well spacing density, while the oil rate of individual well is the opposite. This trend is consistent with the field observation data. Although the complexity of fracture network increases with the well spacing density, the half-length of fractures decreases due to limited extension. Then the final fracture width increases, and more fracturing fluid is stored in fractures, resulting in an increase in water production during the flowback stage and delaying oil breakthrough time. Figure 9 shows the total and average cumulative oil profiles in each case, two opposing trends can be observed. Total cumulative oil increases with the well spacing density, but gradually flattens out as showed in Figure 9a. The 5-year cumulative output of Case 3 and Case 4 is very close, which indicates that the oil increment is much small when the well spacing is less than 200 m. Average cumulative oil of individual well decreases as well spacing decreases as shown in Figure 9b, because the controlled reserves per well decreases with the increase of well spacing density. The distribution of formation pressure after 5-year production also supports this viewpoint, with case 3 and Case 4 pressure drops controlling almost the entire sub reservoir as shown in Figure 10. In addition, the cost of drilling and fracturing treatments increases greatly with the increase in well spacing density. Therefore, it points out that although reducing well spacing can lead to an irreversible increase in water cut, there is an optimal spacing of enhanced oil recovery.

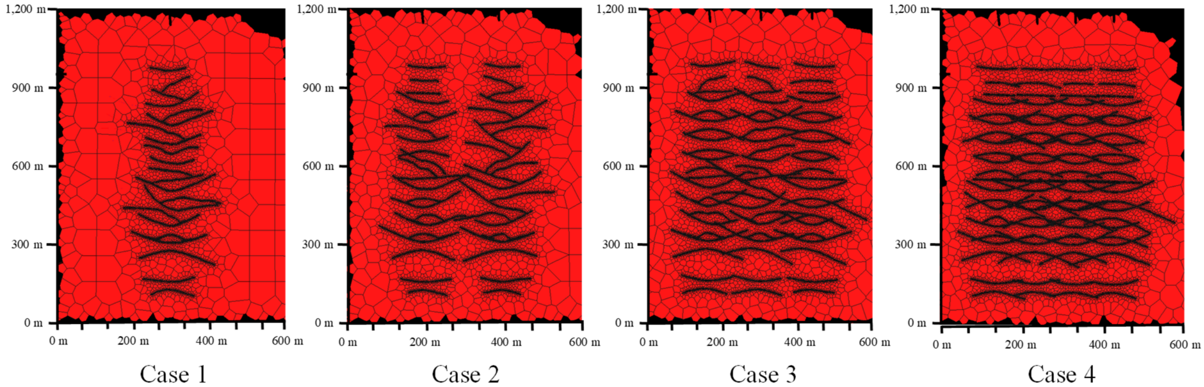


Figure 7. Simulated fracture configuration for different cases.

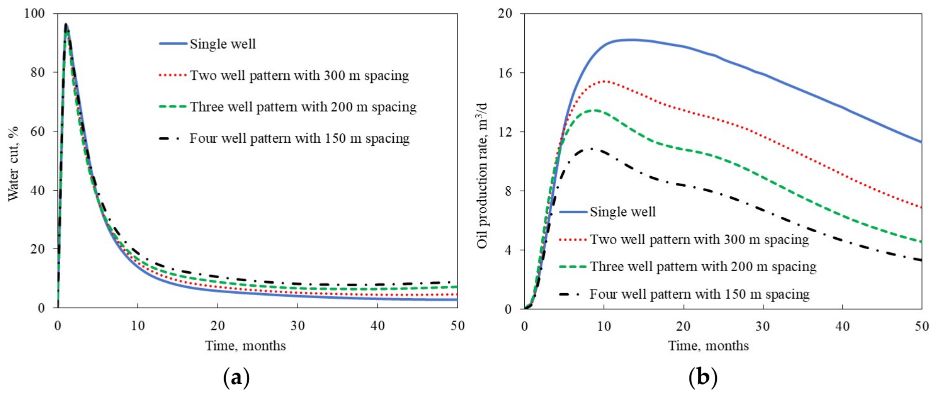


Figure 8. (**a**) Water cut per well profiles under different well spacing. (**b**) Oil production per well profiles under different well spacing.

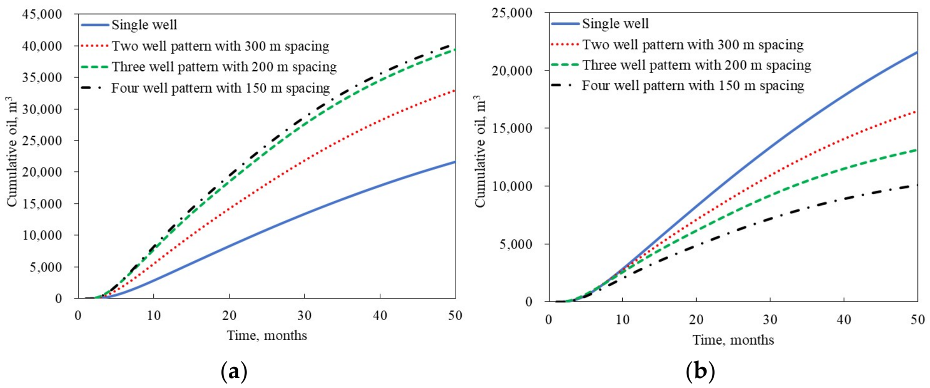


Figure 9. (**a**) Total cumulative oil profiles of all wells in each case. (**b**) Average cumulative oil profiles of individual well in each case.

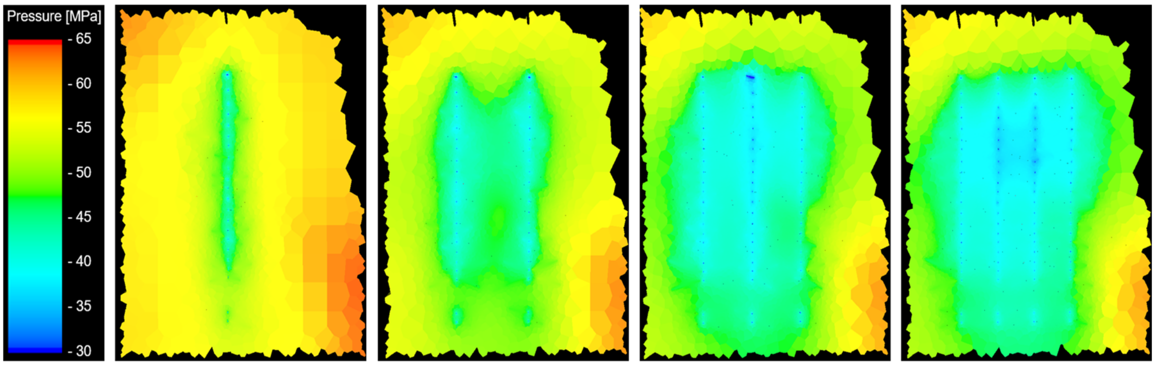


Figure 10. Simulated pressure distribution after 5-year production for different cases.

4. Optimization of Flowback Strategy

Based on the well pattern model with 200 m small well spacing in the previous section, the optimization goal is to pursue the highest cumulative oil during spontaneous production. The impacts of different pressure drop schedules on oil production are simulated respectively, in order to guide the flowback strategy of horizontal well patterns in Mahu Oilfield.

4.1. Constant Pressure Drop Schedules

Due to weak mobility and strong heterogeneity in tight reservoirs, it is difficult to replenish formation energy after pressure depletion. Especially for stress sensitivity reservoirs, a reasonable pressure drop schedule is necessary. Five cases of 0.01, 0.02, 0.04, 0.06 and 0.08 MPa/d are simulated respectively, and the spontaneous production continues until bottom-hole pressure drops to 35.2 MPa.

The results of oil and water production are shown in Figure 11. From Figure 11a, we can find that the spontaneous production duration is significantly extended with the decrease of pressure drop. Although initial oil rate is reduced, cumulative oil is negatively correlated with pressure drop gradient after a long-term production. In contrast, the flow at a slow flowback strategy is more stable and the decline rate of oil production is lower. This is because during the middle and later stages of flowback, the fluid mainly flows into the wellbore through the matrix and secondary fractures. Aggressive pressure drop can cause permeability damage, which is not conducive to stable production. However, if the pressure drop is too low, it is not the optimal scheme, which would excessively prolong the investment return period. For example, when the pressure drop is reduced from 0.04 to 0.02 MPa/d, the oil increment is 9000 m^3 for 2 years; but when it is further reduced to 0.01 MPa/d, the oil increment is only 7100 m^3 for 4 years. Therefore, the pressure drop of 0.02 MPa/d is relatively reasonable. In terms of water production, flowback efficiency also increases monotonically with the decrease of pressure drop. But it is worth noting that the range of fluctuation is very small, within 3%, as shown in Figure 11b. As the newly injected fluid, fracturing water is mainly distributed in the area near the wellbore. Compared with oil phase deep in the reservoir, water phase is easier to be recovered. Overall, although the flowback efficiency is higher under the slow flowback strategy, it is not the main concern, which is beneficial to oil production.

4.2. Tiered Pressure Drop Schedules

In on-site management, the flowback strategy is usually a staged scheme. To further explore a reasonable schedule, two cases with tiered pressure drop are simulated to compare with constant schedules as shown in Table 2. Figure 12 reports the simulated performance under tiered pressure drop schedules. It can be found that the oil rate of case 1 (with gradually decreasing gradient) in the first half period is significantly higher than that of case 2 (with gradually increasing gradient), but there is a sharp reversal in the second half as shown in Figure 12a. Case 1 has a large advantage in initial oil rate, but the decline is relatively fast, while case 2 has an advantage in stable production. In terms of cumulative oil, Case 1 is the highest, even higher than that of constant pressure drop with 0.02 MPa/d. That is, in the early stage of flowback, the aggressive pressure drop is conducive to initial oil rate, due to the high conductivity of fractures and the raised pressure of matrix after fracturing. In the middle and late stages of flowback, it is necessary to gradually decrease the pressure drop to ensure the oil supply, considering the impacts of closure behavior in fracture system and stress sensitivity in matrix. Besides, the trend of flowback efficiency is consistent with that of oil production, but the fluctuation is minor, within 1%. In summary, the pressure drop schedule of gradually decreasing gradient is more suitable for Mahu oilfield, which is beneficial for well productivity and also profits from cash flow with higher initial oil rate.

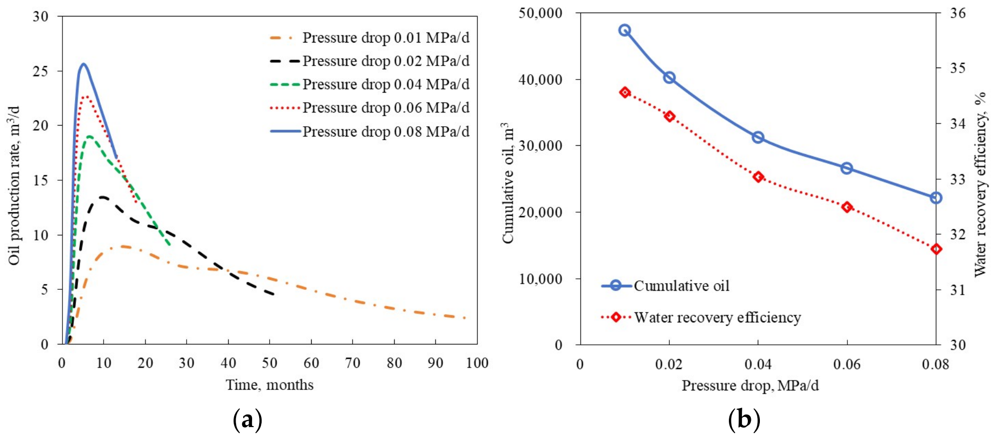


Figure 11. (**a**) Oil production profiles under different constant pressure drop. (**b**) The relationship between constant pressure drop and cumulative oil or water recovery efficiency.

Table 2. Tiered pressure drop schedules.

Case	Pressure Drop (MPa/d)				Control Time (d)			
	Stage 1	Stage 2	Stage 3	Stage 4	Stage 1	Stage 2	Stage 3	Stage 4
1	0.04	0.03	0.02	0.01	180	240	360	720
2	0.01	0.02	0.03	0.04	720	360	240	180

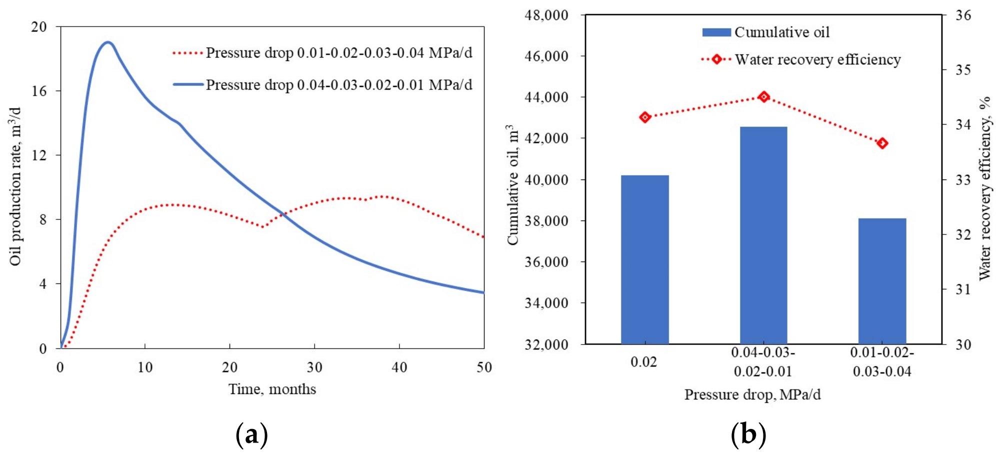
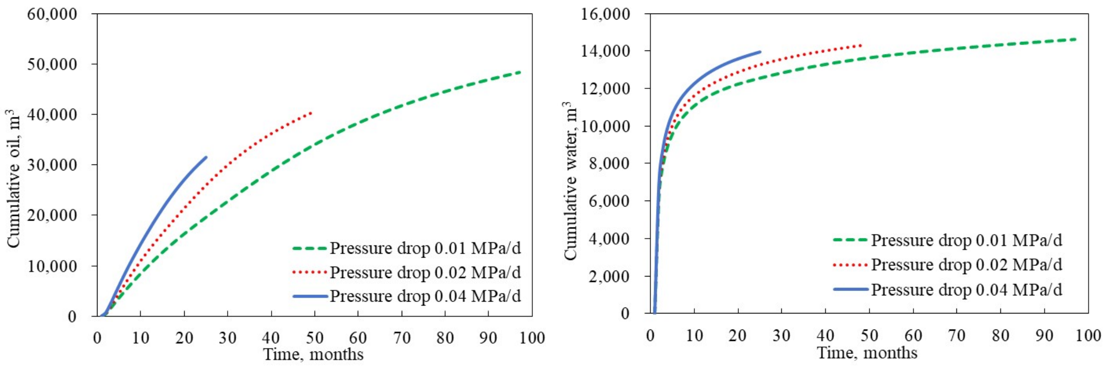


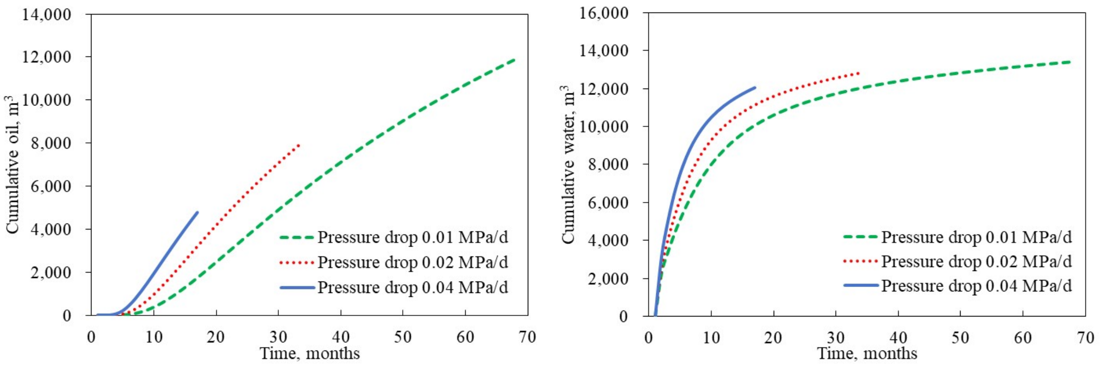
Figure 12. (**a**) Oil production profiles under different tiered pressure drop. (**b**) The relationship between pressure drop and cumulative oil or water recovery efficiency.

4.3. Different Formation Pressure Coefficient

According to the previous studies, the formation pressure coefficient is gradually decreasing under the depletion production mode. However, its impact on the optimization of flowback strategy is unclear. Here, a series of simulations are carried out for the pressure coefficients of 1.44 and 1.22, which are compared with the previous results of 1.66. As Figure 13 shown, the duration of spontaneous production is shortened with the decrease of formation pressure coefficient, and the impact of flowback strategy on oil production is also becoming more significant. Compared to pressure drop of 0.02 MPa/d, the pressure coefficients of 1.66, 1.44 and 1.22 have cumulative oil growth of 19%, 47%, and 214% at 0.01 MPa/d, respectively. Therefore, infill wells should choose a slower flowback strategy with pressure depletion, and the pressure drop of 0.01 MPa/d is more appropriate. Meanwhile, it can be seen that cumulative oil is very sensitive to the pressure coefficient and synchronously falls. Similarly, cumulative water production is also positively correlated with the pressure coefficient, but its fluctuation amplitude is relatively small. Although the production duration has been reduced by more than half under the pressure coefficients of 1.22, the flowback efficiency is still above 25%. This is because the fracture system holds most of the injected water, and the contribution of water production is mainly attributed to the driving mechanism of fracture closure in the initial. Fu et al. [26] reported that for tight oil wells, over 60% of the fracturing fluid is distributed in hydraulic fracture networks. Therefore, the impact of formation pressure coefficient on water flowback is minor.

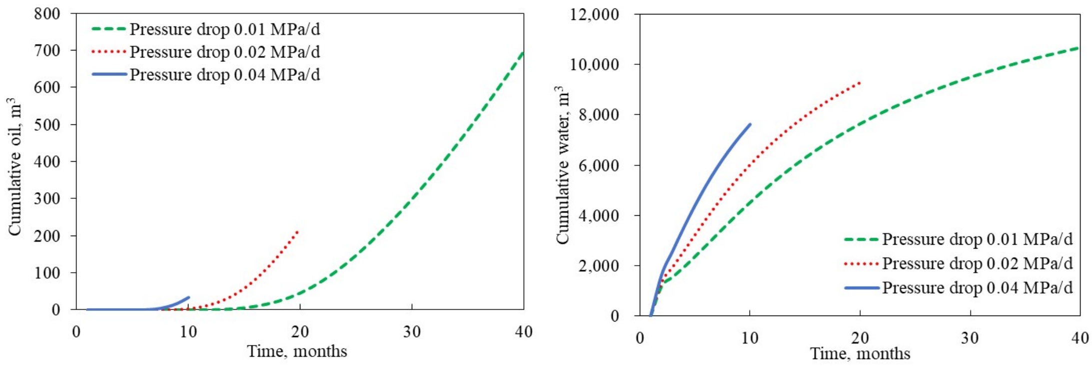


(**a**) Pressure coefficients of 1.66



(**b**) Pressure coefficients of 1.44

Figure 13. *Cont.*



(**c**) Pressure coefficients of 1.22

Figure 13. Oil and water production profiles under different formation pressure coefficient and flowback strategy.

5. Discussion

In this paper, the numerical simulation method of oil-water two-phase flowback in tight reservoir is synthetically optimized. Based on the typical geotechnical engineering data of Mahu oilfield, the integrated numerical models of well pattern from fracturing to production are established by using the commercial simulator. The well performance variance between parent and child wells, as well as different spacing wells, were quantitatively explored. Then the rational flowback strategy suitable for well patterns was optimized. The novelties of this approach are that: (1) the hydraulic fractures are described by simulating propagation process according to the actual geological data and pumping schedule, and the characterization of injected fracturing fluid distribution is completed on this basis. (2) the stress sensitivity in matrix system and the closure behavior in fracture system are distinguished, that is, the impacts of pressure depletion on multi-porosity media are taken into account. (3) the multi-well flowback performance during oilfield dynamic development are systematically studied, such as parent & child wells and simultaneous fracturing of well pattern. (4) the correlation between geotechnical engineering factors and oil-water flow process is established, so that the previous study on local flowback mechanism of a single fracturing stage is extended to the strategy optimization of the whole well patterns.

In view of current confusions on the phenomenon of rising water cut and its impact on productivity of well pattern in tight oil reservoir, a series of models are developed to try to explore the control mechanisms of well performance under multi-well condition. The results show that the driving force of oil flow is weakened and its seepage resistance increases with depletion-drive production of parent wells, causing an increase in water cut of child wells. Meanwhile, in the cases of multi-well undergoing simultaneous fracturing and production, water production increases irreversibly under obvious inter-well interference. However, with appropriate infill well spacing, it is beneficial for enlarging SRV and improving oil recovery (Wang et al., 2022 [27]; Boah et al., 2019 [28]). The trend of increasing water cut does not necessarily mean it is unfavorable for oil production, which is inconsistent with the view of most single well model that there is a certain negative correlation between water and hydrocarbon production.

In this paper, slow flowback strategy should be adopted for stress sensitive reservoirs, which is basically agreed with current literatures. However, the response of well performance to flowback strategy exhibits the following characteristics: (1) slow flowback strategy is not the slower the better, once the liquid rate is too slow, it significantly restricts the investment return cycle. (2) tiered pressure drop schedule is beneficial to accelerate oil rate, and the gradient adjustment sequence should be from large to small gradually. (3) with pressure depletion, the flowback strategy of child wells should be further slowed down, whereas, although minor, it is good for long-term oil production. The results indicate that the impact of oilfield development period on flowback performance should be distinguished, whether it is theoretical research or on-site observation. However, in practical oilfield operation, the strategy is generally empirical and singular. Additionally, the engineers intentionally use aggressive pressure drop to maintain oil rate in the later stage of flowback or spontaneous production (Gao et al., 2021 [29]), which may damage the ultimate oil recovery unfortunately. Overall, the impact of flowback strategy on well productivity is complicated, and it cannot be simply assumed that the similar scheme is applicable to the same block.

Due to the difficulty in achieving full coupling of fracture propagation and reservoir simulation using existing available simulators, the distribution of fracturing fluid here is still simulated through water injection on the basis of expanded complex fractures. In addition, because of the limitations of current simulator, the filtration and imbibition of fracturing fluid only consider the effects of capillary force and gravity, ignoring the osmotic pressure (Wang et al., 2021 [7]) and clay hydration (Xu et al., 2019 [30]). These mechanisms have been experimentally or theoretically proven to have an impact on fluid distribution and flowback. Therefore, in future work, it is necessary to further improve the mathematical model and match the corresponding simulator, so as to accurately character flowback performance and guide appropriate strategy.

6. Conclusions

Based on the typical data of tight oil well patterns, a series of geotechnical engineering numerical models were established, which would accurately depicting pressure and saturation distribution of stimulated reservoir. Accordingly, the reasonable flowback strategy for well patterns could be optimized for the tight reservoir in Mahu Sag.

With the depletion production of adjacent parent wells, the rising water cut trend of child wells was irreversible. This is because that seepage driving force of the matrix is weakened, accompanied by an increase in seepage resistance. However, with appropriate well spacing deployment, infill wells can improve overall oil recovery and the increase in water production is not a concern.

For stress sensitive reservoirs, well pattern should adopt a slow flowback strategy after synchronous fracturing. Meanwhile, there is an optimal pressure drop gradient range, and excessively low pressure drop impacts the return on investment. It is noted that the pressure drop schedule with gradually decreasing gradient is more beneficial for well productivity than that of constant gradient. This not only increases the initial oil rate, but also reduces the damage caused by stress dependent permeability in the middle and later stages.

The impact of oilfield development period on flowback performance cannot be ignored. Even in the same block, the flowback strategy should be distinguished and further slowed down as pressure depletion.

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