Research Article

Hydrocarbon Gas Flooding Optimization considering Complex Fracture Networks through Numerical Simulation in the Tight Oil Reservoirs

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Field data indicates that oil production decline quickly and the oil recovery factor is low due to low permeability and insufficient energy in the tight oil reservoirs. Enhanced oil recovery (EOR) is required to improve the oil production rates of tight oil reservoirs. Gas flooding is a good means to supplement formation energy and improve oil recovery factor, especially for hydrocarbon gas flooding when CO2 is insufficient. Due to the permeability in some areas is too low, the injected gas cannot spread farther, and the EOR performance is poor. So multifractured horizontal well (MFHW) are usually used to assist gas injection in oilfields. At present, there are few studies on the optimization of hydrocarbon gas flooding parameters especially under the complex fracture network. This article uses unstructured grids to characterize the complex fracture networks, which more realistically shows the flow of formation fluids. Based on actual reservoir data, this paper establishes the numerical model of hydrocarbon gas flooding under complex fracture networks. The article conducts numerical simulation to analyze the effect of different parameters on well performance and provides the optimal injection and production parameters for hydrocarbon gas flooding in the M tight oil reservoir. The optimal injection-production well spacing of the M tight oil reservoir is about 800 to 900 m. The EOR performance is better when the total gas injection rates are about 0.45 HCPV, and gas injection rates of each well are about 3000 to 3500 m3/d (0.021 to 0.025 HCPV/a). The recommended injection-production ratio is about 1.1 to 1.2. This work can offer engineers guidance for hydrocarbon gas flooding of the MFHW with complex fracture networks. This work can also offer engineers guidance for hydrocarbon gas flooding of the MFHW with complex fracture networks.

1. Introduction

Conventional oil resources are unable to meet the requirement of economic development. Unconventional oil reservoirs have become the significant choice to supplement the energy demand attributed to its abundant geological resources all over the world [1–3]. Horizontal well hydraulic fracturing technology is one of the effective means for increasing oil production in tight reservoirs [4–9]. Generated fractures can effectively increase the ability of fluid flow in tight rocks, and horizontal wells can better increase the well-controlled areas [10–14].

However, oil production of tight oil reservoirs shows the rapid decline and low oil recovery factor under primary depletion [15–17]. Therefore, different EOR methods have been used to increase the oil production in tight oil reservoirs, such as water flooding, water huff-n-puff, low-salinity water spontaneous imbibition, gas huff-n-puff, gas...
Hydrocarbon gas flooding optimization considering complex fracture networks through numerical simulation

Research on gas flooding in the tight oil reservoirs

Establish a MFHW numerical model

Parameters of reservoir, wells and fluid

Reasonable injection-production parameter optimization

Well spacing Total injection Injection rate Injection-production ratio

Propose the optimal injection-production parameters

Clear the effects of injection-production parameters of hydrocarbon gas flooding under complex fracture networks

**Figure 1:** Flowchart of the work.

**Figure 2:** The numerical model includes a producer and six injectors.

(a) X-Y view of numerical model  (b) Enlarged view of fractures and grids

**Figure 3:** View of numerical model.
Table 1: The basic parameters of reservoir, wells, and fluid.

| Parameters                  | Values                        | Parameters                  | Values        |
|-----------------------------|-------------------------------|-----------------------------|---------------|
| Model size                  | 2500 m × 2500 m × 30 m        | Average permeability of matrix | 0.6 mD       |
| Model area                  | 6.25 km²                      | Average permeability of fracture | 127.5 mD     |
| Number of grids             | 125 × 125 × 5                 | Porosity                    | 0.06          |
| Grid size                   | 20 m × 20 m × 6 m             | Initial reservoir pressure  | 44.3 MPa      |
| Horizontal well length      | 1600 m                       | Reservoir temperature       | 88.6 °C       |
| Reservoir depth             | 3350 m                       | Saturation pressure of crude oil | 18.1 MPa    |
| Number of fractures         | 56                            | Density of crude oil        | 0.81 t/m³     |

Figure 4: Oil-water relative permeability curves.

Figure 5: Gas-oil relative permeability curves.

Table 2: Parameters of the numerical model.

| Parameters                  | Values                      | Basic case |
|-----------------------------|-----------------------------|------------|
| Well spacing (m)            | 500, 700, 900, 1000, 1200   | 900        |
| Total injection (HCPV)      | 0.2, 0.25, 0.3, 0.35, 0.4, 0.45, 0.5, 0.6 | 0.45       |
| Injection rate (m³/d)       | 2500, 3000, 3500, 4000, 4500, 5000, 5500 | 3000       |
| Injection-production ratio  | 0.9, 1, 1.1, 1.2, 1.3, 1.4   | 1.1        |
**Figure 6:** (a) Recovery factor and oil exchanged rate through hydrocarbon gas flooding under different well spacing; (b) gas-oil ratio under different well spacing.

**Figure 7:** Cumulative oil production under different injection-production well spacing.
flooding, and chemical EOR [18–23]. Water injection may be a not good choice due to the water sensitivity in the tight oil reservoir. Gas injection becomes a preferred approach to enhance the oil production for the tight oil reservoir [24–27]. As the application of CO₂ flooding is restricted by gas sources [28], hydrocarbon gas flooding has gradually become popular means [29]. The main controlling factors and oil-increasing mechanism of hydrocarbon gas flooding are of great significance for improving oil production. Shyeh-Yung [30] analyzed the influence of the composition and pressure of the injected gas on the gas flooding results through the phase experiment. Shimizu and Takahashi [31] conducted laboratory tests on the displacement process and feasibility of hydrocarbon gas flooding in reservoirs after waterflooding. The results show that hydrocarbon gas flooding can effectively improve oil recovery. Vilela et al. [32] analyzed the influence of gas injection pressure on oil recovery for the reservoir. Yu et al. [29] used laboratory experimental methods to evaluate the feasibility of gas injection after water injection in the tight oil reservoir and analyzed the influence of gas injection rate on the effect of gas injection and oil displacement. Luo et al. [33] investigated the different gas flooding (CO₂, CO₂-rich flue gas, oilfield associated gas, and N₂) processes in the Bakken reservoir in Canada through laboratory experiments. The results show that the reduction of crude oil viscosity and crude oil expansion is the main mechanisms of gas flooding to enhance oil recovery. Sun et al. [34, 35] used fractal and microseismic fracture characterization techniques to investigate the effect of CO₂ Huff-n-Puff in complex fracture networks of unconventional liquid reservoirs based on two laboratory experiments and several field researches. Wu et al. [36] present a method of assessing the effect of the stress shadow in the complex fracture network, based on a developed unconventional fracture model (UFM). Dheiaa et al. [37] established single-porosity and dual-permeability models to compare the development effects of continuous gas injection and steam stimulation in the US-Bakken and Canadian-Bakken reservoirs.

It is found that most works only studied the injection and production parameters of hydrocarbon gas injection in horizontal wells and did not consider the influence of complex fracture networks during hydrocarbon gas flooding [38, 39]. Therefore, it is necessary to optimize the injection and production parameters of hydrocarbon gas flooding under complex fracture networks in tight oil reservoirs. This paper firstly establishes the numerical model of hydrocarbon gas flooding under complex fracture networks. Then, the paper conducts numerical simulation to analyze the effect of different parameters on well performance (well spacing, total injection, injection rate, and injection-production ratio). Lastly, the paper provides the optimal injection and
production parameters for hydrocarbon gas flooding in the M tight oil reservoir. Figure 1 shows the specific process. This work can offer engineers guidance for hydrocarbon gas flooding of the MFHW with complex fracture networks.

2. Numerical Model and Design

2.1. Numerical Model. Based on the geology information and parameters, the numerical model is firstly established to investigate the effect of injection and production parameters on hydrocarbon gas flooding performance under complex fracture networks in the M tight oil reservoirs. The numerical model includes a producer (MFHW) and six injectors (vertical wells), shown in Figure 2. First, a horizontal well is set up in the center of the model. In order to ensure that the reserves of the entire model can be controlled, 6 vertical wells are set around.

To improve the accuracy and efficiency, the unstructured grid is used to describe fractures while rectangular grids are used to describe the matrix in this paper. The article uses the fracturing design software-Mangrove. The pump injection program is set by software to simulate the fracturing process. Finally, unstructured grids are used to characterize fractures generated in horizontal wells. The area where the fracture and the horizontal well intersect each other has a greater grid density. The flow between the matrix and the fracture is simulated, and the fluid mainly flows into the horizontal well through the fracture. Figure 3(a) shows the grid distribution of the numerical model, and Figure 3(b) shows the enlarged view of fractures and grids.

2.2. Parameters of Reservoir, Wells, and Fluid. The basic parameters of reservoir and wells can be seen in Table 1. The permeability of M reservoir is low, and the physical

![Figure 9](http://pubs.geoscienceworld.org/gsa/lithosphere/article-pdf/doi/10.2113/2021/4169983/5462729/4169983.pdf)
properties are poor. This paper considers that the CO₂ gas source of M reservoir is insufficient, and the high miscible pressure of N₂ flooding results in poor oil displacement. Therefore, hydrocarbon gas flooding is used for development. The original formation pressure of the reservoir is 44.3 MPa, and the saturation pressure is 18.1 MPa. The reservoir temperature is 88.6°C. The miscible pressure is 38.5 MPa. The hydrocarbon gas injected into the reservoir increases the formation pressure. When the formation pressure reaches the miscible pressure, it can form a miscible flooding. The fluid phase data adopts the fitting result of the formation fluid phase behavior simulation.

The relative permeability curves are obtained from experimental results. Figure 4 shows the oil-water relative permeability curves of matrix and fracture, respectively. Figure 5 shows the gas-oil relative permeability curves of matrix and fracture, respectively.

2.3. Design of Injection and Production Parameters. To analyze the feasibility of hydrocarbon gas flooding in tight oil reservoirs, sensitivity analysis of different injection and production parameters is discussed, including the well spacing, total gas injection rates, injection rates of each well, injection, and production ratio [40, 41]. The EOR performance can be evaluated based on the oil exchange rate, oil and gas ratio, and recovery factor. The oil exchange rate is defined as the ratio of the increased oil production to the injected gas volume during the gas injection (increased oil production per 1 t gas injection) [34, 35].

\[
\text{Oil exchange rate} = \frac{\text{Cumulative increase in oil production}}{\text{Cumulative gas injection}}.
\]  

(1)

Specific parameters are shown in Table 2. Different cases are compared to primary depletion. The limit of daily oil rates is 30 m³/d, and the minimum bottom well pressure is 20 MPa. Note: hydrocarbon gas conversion relationship (1 t = 1048.77 m³).

HCPV: hydrocarbon pore volume.

3. Injection and Production Parameter Optimization

The effect of injection and production parameters need to be simulated and analyzed to obtain the optimal injection and production schemes for hydrocarbon gas flooding in tight oil reservoirs. The injection and production parameters discussed here mainly include the well spacing, total gas injection rates, injection rates of each well, injection, and production ratio. Due to the grid of the matrix is set up with the regular grid, the calculation speed of the model is greatly improved. The model has good computational convergence, and it takes about 3 hours to simulate a single scheme.

3.1. Well Spacing. Five kinds of well spacing (i.e., 500 m, 700 m, 900 m, 1000 m, and 1200 m) are designed to analyze its impact of production performance of the MFHW. Gas injection is started in the second year after depletion, and other conditions are kept the same. The influence of different injection-production well spacing on EOR results is studied by comparing the increased oil production and oil exchanged rate.

The oil exchanged rate increases as the well spacing increases, shown in Figure 6(a). However, the increasing trend becomes minor when well spacing increases from 900 to 1200 m. The well-controlled recovery factor is decreased with the increase of well spacing since the well-controlled reserves become larger under larger well spacing. Gas-oil ratio will quickly increase under small well spacing (e.g., 500 m), as shown in Figure 6(b). When the injection-production well spacing is greater than 900 m, the production
Figure 11: Formation pressure after gas flooding under different total hydrocarbon gas injection rates.

Figure 12: Oil recovery factor and oil exchanged rate under different injection rates of each well.
gas-oil ratio is less than 800 m$^3$/m$^3$. The larger the injection-production well spacing is, the later the gas-oil ratio of production wells will rise, and the smaller the final gas-oil ratio will be.

It is obviously found that the cumulative oil production rates are increased significantly, shown in Figure 7. Although the biggest well spacing (1200 m) yields the highest cumulative oil production rates, the enhanced degree of cumulative oil production rates becomes much minor when the well spacing is larger than 900 m.

The fracture networks provide channels for gas flow. When the injection-production well spacing is small, the gas quickly enters the wellbore along with the fractures. The production gas-oil ratio rises rapidly (Figure 8(a)). Gas breakthrough is easier to happen under small well spacing (Figures 8(a) and 8(b)). The gas breakthrough is mitigated when the well spacing is increased to 900 and 1000 m, as shown in Figures 8(c) and 8(d). Too large controlled area leads to low flooding efficiency, so that the increased cumulative oil production rates are minor when the well spacing is further increased to 1200 m (Figures 8(e)). Therefore, the optimal injection-production well spacing of the M tight oil reservoir is about 800 to 900 m.

3.2. Total Gas Injection Rates. The total gas injection rates are changed (0.2, 0.25, 0.3, 0.35, 0.4, 0.45, 0.5, and 0.6 HCPV) to obtain the optimal gas injection rates. Gas injection starts in the second year of development, and other conditions remain unchanged. The oil recovery factor is significantly increased with the increase of total gas injection rates (from 0.2 to 0.6), shown in Figure 9(a). But the oil exchanged rate shows different trends. The oil exchanged rate rises to 1.05 t/t when the total gas injection rates change from 0.2 to 0.3. Then, the oil exchanged rate decreases gradually from 1.05 to 0.91 t/t. Figure 9(b) shows that when the total gas injection is greater than 0.45 HCPV, the gas-oil ratio is greater than 900 m$^3$/m$^3$, indicating obvious gas breakthrough.
The daily oil production rate under different total gas injection is shown in Figure 10. The formation pressure distribution after gas flooding under different total hydrocarbon gas injection rates is shown in Figure 11. The fracture network increases the well control area of the horizontal well. It can be seen from Figure 11(a) that the pressure near the fractures is greatly reduced, which shows that the fractures also increase the scope of the pressure drop funnel. When the total gas injection rates are 0.2 HCPV, most of the injected hydrocarbon gas has not yet expanded to the production well so that the pressure around the injection wells is high (Figure 11(a)). As the gas injection rates increase, the hydrocarbon gas gradually spreads to the production well, the gas-oil ratio of the production well gradually increases, and the formation pressure gradually decreases from Figure 11(b) through Figure 11(h).

Although increasing the total injection rates of hydrocarbon gas can fully supplement the formation energy and effectively improve the oil recovery factor, but the oil exchanged rate has been reduced. Combined with the analysis of the gas-oil ratio, the EOR performance is better when the total gas injection rates are about 0.45 HCPV.

3.3. Gas Injection Rates of Each Wells. The hydrocarbon gas injection rate of each well needs to be analyzed after the optimal total injection rates (0.45 HCPV) and well spacing (900 m) are determined. Seven groups of gas injection rate for each well are designed, that is, 2500, 3000, 3500, 4000, 4500, 5000, and 5500 m$^3$/d (hydrocarbon gas: $1 \text{t} = 1048.77 \text{m}^3$). Then, dimensionless gas injection rate can be also obtained ($0.018$, $0.021$, $0.025$, $0.028$, $0.032$, $0.035$, and $0.039$ HCPV/a). It is observed that the effect of gas injection rate for each well on oil recovery factor is quite minor compared to the total gas injection rates (Figure 12). However, the oil exchanged rate shows bigger changing feature. The oil exchanged rate increases when the gas injection rate changes from is 2500 to 3000 m$^3$/d, while it begins to decline when the gas injection rate changes from is larger than 3000 m$^3$/d.

Although the impact of gas injection rate for each well on daily oil production rates can be clearly found in Figure 13(a), while the difference among the final cumulative oil production rates under different gas injection rate of each well is not obvious, as shown in Figure 13(b).

The gas saturation distribution after gas flooding under different gas injection rates is shown in Figure 14(a) to Figure 14(d). It is obviously found that gas saturation distribution is not changed significantly when the hydrocarbon gas injection rates are increased to 2500 to 5500 m$^3$/d. This phenomenon is consistent with the characteristic of cumulative oil production under different gas injection rates of each well (Figure 13(b)).

When the gas injection rate is greater than 2500 m$^3$/d, the hydrocarbon gas can quickly diffuse from the gas injection well to the fracture (Figure 14(a) to Figure 14(d)). The fracture network provides good flow channels for gas flow. Therefore, the gas quickly enters the wellbore and is produced by the production well. As a result, the injected hydrocarbon gas did not displace crude oil, and the recovery rate was low.

Hydrocarbon gas injection rates have little effect on EOR, but the low gas injection rates are easier to form a stable interface flooding. In summary, the optimal gas injection rates of each well of the M tight oil reservoir is about 3000 to 3500 m$^3$/d (0.021 to 0.025 HCPV/a).

3.4. Injection and Production Ratio. Six kinds of injection-production ratios (0.9, 1, 1.1, 1.2, 1.3, and 1.4) are defined
to analyze its influence on production performance. The well spacing between producer and injectors is 900 m, and gas injection will start in the second year after depletion. The total gas injection rates are 0.45 HCPV, and the limit of gas injection rate is 5500 m³/d. Other conditions remain unchanged. Figure 15(a) shows that the oil recovery factor increases with the increase of injection-production ratio from 0.9 to 1.4. Especially, a sharp increase on oil recovery factor can be observed when injection-production ratio rises from 0.9 to 1.1. However, the rise of injection-production ratio leads to the decrease of oil exchanged rate from 1.32 to 0.91. This is because the increase of injection-production ratio leads to a rapid increase in the gas-oil ratio, and gas breakthrough is prone to occur. When the injection-production ratio is between 1.0 and 1.2, the gas-oil ratio increases significantly, shown in Figure 15(b).

Figure 16 indicates the daily oil production rates and cumulative oil production rates. Compared to primary depletion, the daily oil production rates are significantly enhanced by gas flooding especially when the injection-production ratio is higher than 1.1 (Figure 16(a)). The difference becomes minor when the injection-production ratio exceeds 1.2. Earlier gas breakthrough can cause earlier decline of daily oil production rates. Compared with depletion, the cumulative oil production rates are increased a lot (from $11.5 \times 10^4$ to $21.9 \times 10^4$ m³) after gas injection, shown in Figure 16(b). When the injection-production ratio is larger than 1.3, the cumulative oil production rates are not significantly enhanced due to possible gas breakthrough.

The gas flooding effect becomes poor when the injection-production ratio is less than 1.1. Furthermore, gas breakthrough is easier to occur when the injection-production ratio is smaller.
ratio is larger, which is not beneficial to improve the oil displacement effect. Therefore, the recommended injection-production ratio is about 1.1 ~ 1.2.

4. Summary and Conclusions

This paper analyzes the effect of injection and production parameters of hydrocarbon gas flooding under complex fracture networks through numerical simulation and proposes the optimal injection and production parameters for target reservoirs, which provides guidance for hydrocarbon gas flooding of the MFHW with complex fracture networks.

(1) Increasing the well spacing can improve the EOR phenomenon. The recommended injection-production well spacing of the M tight oil reservoir is about 800 to 900 m

(2) Increasing the total injection rates of hydrocarbon gas can fully supplement the formation energy and effectively improve the oil recovery factor. Combined with the analysis of the oil exchanged rated and gas-oil ratio, the EOR performance is better when the total gas injection rates are about 0.45 HCPV

(3) The low gas injection rates are easier to form a stable interface flooding. The optimal gas injection rates of each well are about 3000 to 3500 m³/d (0.021 to 0.025 HCPV/a).

(4) The gas breakthrough is easier to occur when the injection-production ratio is larger, which is not beneficial to improve the oil displacement effect. Therefore, the recommended injection-production ratio is 1.1-1.2

Data Availability
The data can be found in the manuscript.

Conflicts of Interest
The authors declare that they have no conflicts of interest.
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