Tight oil reservoir production characteristics developed by CO₂ huff ‘n’ puff under well pattern conditions

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Abstract
Tight oil reservoirs have poor physical properties, and the problems including rapid oil rate decline and low oil recovery degree are quite common after volume fracturing. To obtain a general understanding of tight oil reservoir production improvement by CO₂ huff ‘n’ puff, the high-pressure physical properties of typical tight oil samples are measured. Combining the typical reservoir parameters, the production characteristics of the tight oil reservoir developed by the CO₂ huff ‘n’ puff are numerically studied on the basis of highly fitted experimental results. The results show that: (1) during the natural depletion stage, the oil production rate decreases rapidly and the oil recovery degree is low because of the decrease in oil displacement energy and the increase in fluid seepage resistance. (2) CO₂ huff ‘n’ puff can improve the development effect of tight oil reservoirs by supplementing reservoir energy and improving oil mobility, but the development effect gradually worsens with increasing cycle number. (3) The earlier the CO₂ injection timing is, the better the development effect of the tight reservoir is, but the less sufficient natural energy utilization is. When carrying out CO₂ stimulation, full use should be made of the natural energy, and the appropriate injection timing should be determined by comprehensively considering the formation-saturation pressure difference and oil production rate. The research results are helpful for strengthening the understanding of the production characteristics of tight oil reservoirs developed by CO₂ huff ‘n’ puff.

Keywords Tight oil reservoir · Production characteristic · CO₂ · Huff ‘n’ puff · Injection timing

Introduction
Tight oil resources are widely distributed and have large reserves in China, with technically recoverable amounts of 20–25 × 10⁸ t (Zou et al. 2015), and they have become the main source of unconventional oil production (Zhu et al. 2019). The matrix permeability of tight oil reservoirs is extremely low because of the wide distribution of nanoscale pore-throat systems (Zhao et al. 2020a). Thus, there is generally no natural industrial production of tight oil reservoirs due to their poor physical properties. Presently, the industrial exploitation of tight oil resources mainly relies on volume fracturing (Guo et al. 2019; Suppachoknirun and Tutuncu 2017). After volume fracturing, the seepage conditions in the fractured area are significantly improved because of the formation of the three-dimensional fracture network in the reservoir (Wang et al. 2017; Eltahan et al. 2021; Dong et al. 2019), and the oil production rate can be increased significantly.

However, the energy (i.e., the reservoir pressure) consumption of tight oil reservoirs is too fast by natural depletion, and problems are quite common, including rapid oil production rate decline and poor reservoir fluid recovery. Thus, the oil recovery degree by natural depletion is generally lower than 10% for tight oil reservoirs. An effective supply of reservoir energy is the key to improving the production performance of tight oil reservoirs (Kang et al. 2020; Wei et al. 2021). Water and gas are the most studied injectants for reservoir energy supplementation (Wu et al. 2020; Zou et al. 2019). Compared with water, the gas viscosity is lower and easier to inject (Zhou et al. 2020). In addition, there usually exists a moderate amount of clay minerals in tight oil reservoirs, and the injected water can easily...
cause clay expansion, which will partially block the pores or throats, resulting in a significant reduction in the reservoir permeability. When gas is injected, similar reservoir damage problems can be avoided because gas does not easily react with reservoir minerals or fluids (Mohammad et al. 2018; Song et al. 2020).

Among the studied gases, CO$_2$ gained attention as early as the 1950s, from which related research and field practice in Enhanced oil recovery (EOR) were carried out (Holm 1982). Studies show that CO$_2$ has important mechanisms including dissolution, viscosity reduction and swelling (Yu et al. 2019; Li et al. 2021) which are quite important for oil recovery. Approximately 34 CO$_2$-EOR projects (Hill et al. 2020) and more than 100 CO$_2$-EOR projects (Lake et al. 2019) have been reported in China and the United States, respectively. As early as 1988, Monger and Coma (Monger and Coma 1988) proposed that CO$_2$ huff ‘n’ puff was a promising EOR method. Taking heavy oil exploitation as an example, Li et al. (Li et al. 2020) experimentally investigated the production performance of CO$_2$ huff ‘n’ puff in recovering extra heavy oil and observed significant oil recovery improvement. Zhou et al. (Zhou et al. 2018) reviewed experimental studies, pilot field tests and numerical simulation studies of CO$_2$ injection in heavy oil recovery and concluded that CO$_2$ huff ‘n’ puff is one of the most successful EOR methods in heavy oil production.

In recent years, CO$_2$ huff ‘n’ puff has proven to be effective in tight oil recovery. Trivedi and Babadagli (Trivedi and Babadagli 2010) experimentally studied oil recovery by CO$_2$ injection in artificially fractured cores and found that the pressure blowdown could increase oil recovery significantly until a certain critical pressure. Wang et al. (Wang et al. 2020) studied the CO$_2$ huff ‘n’ puff process with staged fracturing wells by large-scale physical simulation experiments and found that CO$_2$ huff ‘n’ puff can improve the development effect of tight oil recovery. Li et al. (Li et al. 2017) experimentally studied the effect of the injection pressure on enhancing oil recovery in shale cores during the CO$_2$ huff ‘n’ puff process and found that high oil recovery could be obtained when the injection pressure was above the minimum miscibility pressure. Zhao et al. (Zhao et al. 2020b) experimentally studied the recovery behavior by CO$_2$ injection using MRI and found that the fluid mobility range could be expanded and the displacement efficiency could be improved compared with water flooding. Burrows et al. (Burrows et al. 2020) reviewed laboratory studies and pilot field tests of CO$_2$ huff ‘n’ puff in unconventional oil recovery and concluded that relevant research using CO$_2$ should be further studied.

From the above analysis, CO$_2$ injection has been widely used to improve oil recovery, and it has achieved good results, especially in conventional reservoir exploitation. However, for tight oil reservoirs, numerical studies of CO$_2$ huff ‘n’ puff on tight oil reservoir exploitation are quite limited compared with experimental studies, and further research should be carried out to investigate the effects of CO$_2$ huff ‘n’ puff especially at the field scale. To improve the understanding of the production effect of tight oil reservoirs by CO$_2$ huff ‘n’ puff after natural depletion, a laboratory experiment was carried out, and a multiwell numerical simulation model was established based on experimental results and typical reservoir parameters. Then, the production performance was studied, and the effects of CO$_2$ were discussed.

**Model establishment**

**Experimental section**

The studied tight oil reservoir XX developing the Chang 7 Formation was located in the Ordos Basin with an average reservoir top depth of 2230 m. The reservoir oil sample was obtained by bottom-hole sampling from a typical tight oil well, and the corresponding measured depth of the well production interval was in the range of 2244–2250 m. The laboratory analysis was carried out using this sample. The saturation pressure of this oil sample is estimated at 8.1 MPa and the API gravity of the dead oil is 37. The reservoir oil volume factor is 1.27 with a solution gas–oil ratio of 73 m$^3$/m$^3$. Based on the experimental results, the fluid model is established using the CMG-WinProp module, and the experimental and fitting results are shown in Figs. 1, 2, 3.

From Figs. 1, 2 and 3, the relative volume increases slightly with decreasing pressure and increases greatly when the pressure is below the saturation pressure; in addition, the oil density and oil viscosity decrease with decreasing...
pressure. The variation trends of the relative volume, oil density and oil viscosity are consistent with the experimental results, and the corresponding average fitting errors are 0.534%, 0.311%, and 1.17%, respectively. The fitting accuracy is high enough and meets the requirements of engineering calculations.

**Basic model**

The permeability heterogeneity of reservoir XX is relatively strong with a variation coefficient of 0.53. The reservoir physical properties are poor, with an average porosity of 9.3% and air permeability of $0.17 \times 10^{-3}$ μm² by core analysis. To obtain a general understanding of tight oil reservoir production improvement by CO₂ huff ‘n’ puff, a basic model was established on average by neglecting the heterogeneity of reservoir parameters. Combined with the high-pressure physical property experimental results above, the numerical simulation model of tight oil reservoir development by CO₂ huff ‘n’ puff was established using the CMG-STARS module. The fluid system is composed of three phases (oil phase, gas phase and water phase), and it is divided into five components (CO₂, CH₄, C₂₋₆, C₇+, H₂O), as shown in Table 1. The stress sensitivity is characterized by a Carman–Kozeny-type formula, as shown in Eq. (1). The oil and water relative permeability curves are shown in Fig. 4, and the co-flow area for oil and water is narrow. The model is assumed to be in a closed boundary condition. The total oil

**Table 1** Composition of the reservoir oil

| Components | Mole fraction, % | Pseudo-components |
|------------|-----------------|------------------|
| CO₂        | 0.088           | CO₂              |
| C₁         | 20.860          | C₁               |
| C₂         | 7.957           | 31.170           | C₂₋₆          |
| C₃         | 10.407          |                  |
| iC₄        | 1.56            |                  |
| nC₄        | 4.343           |                  |
| iC₅        | 1.51            |                  |
| nC₅        | 1.937           |                  |
| C₆         | 3.456           |                  |
| C₇         | 5.207           | 47.882           | C₇₊          |
| C₈         | 2.521           |                  |
| C₉         | 5.572           |                  |
| C₁₀        | 3.33            |                  |
| C₁₁+       | 31.252          |                  |
| Sum        | 100             |                  |
reserve of the model is $2.97 \times 10^5 \text{ m}^3$, and the basic reservoir parameters are shown in Table 2.

$$k_a = k_{a,0} \exp \left[ m \left( \frac{\phi_p - \phi_0}{1 - \phi_0} \right) \right]$$  \hspace{1cm} (1)

where $k_a$ is the current absolute permeability; $k_{a,0}$ is the initial absolute permeability; $\phi_0$ is the initial reservoir porosity; $\phi_p$ is the current reservoir porosity at reservoir pressure $p$; and $m$ is the model coefficient, which is set to 70 by fitting the experimental data.

The nonlinear flow of the reservoir fluid is modeled by modified Darcy’s law, as shown in Eq. (2)

$$\begin{cases} 
    v = 0 & \nabla p < G \\
    v = -\frac{k_a}{\mu} \nabla p \left( 1 - \frac{G}{\nabla p} \right) & \nabla p > G 
\end{cases}$$  \hspace{1cm} (2)

where $v$ is the fluid velocity; $\mu$ is the fluid viscosity; $\nabla p$ is the pressure gradient; and $G$ is the pseudo-threshold pressure gradient, which is set as 150 kPa/m according to the experimental results.

The rhombus well pattern is adopted in the model because it is commonly used during the development of low-permeability (tight) oil reservoirs (Guo et al. 2020; Zhu et al. 2012; Wang et al. 2013; Li et al. 2015). The model size is $1015 \times 615 \times 10 \text{ m}$ and there are 9 vertical wells with a well spacing of 500 m and row spacing of 150 m, as shown in Fig. 5. All wells are completed in the whole layers, and then volume fractured. Based on the principle of equivalent conductivity, the logarithmically spaced—locally refined grid (Rubin 2010) is used to model the fluid flow in the fractures, where the permeability is high in the center of the fractured zone, and it decreases logarithmically away from the center. The half-length of the main fracture is 125 m, and the equivalent conductivity of the main fracture is $25 \times 10^{-3} \mu \text{m}^2\cdot\text{m}$, and the fracture bandwidth is 105 m.

In the production simulation study, a three-year natural depletion production was carried out followed by a 3-cycle CO$_2$ huff ‘n’ puff production. Each cycle is divided into three periods: CO$_2$ injection, well soaking and well production. In each cycle, CO$_2$ is injected into each interior well with an injection rate of 20t/d (half for edge wells) for 20 days, and the soaking time is 30 d. Each well is produced at a bottom-hole pressure of 80% of the saturation pressure during the depletion production stage.

### Production characteristics

#### Oil production

The oil production curves of the model and each well are shown in Figs. 6, 7, respectively. In the natural depletion production stage, the reservoir pressure gradually decreases centered on each well with increasing time (Fig. 8) because of reservoir fluid withdrawal. The gradual expansion of the low-pressure range indicates that the oil displacement energy continues to decline. In addition, from Fig. 9, the reservoir pressure drop results in a significant decrease in

| Parameter                           | Value   | Parameter             | Value   |
|-------------------------------------|---------|-----------------------|---------|
| Initial reservoir pressure, MPa     | 17      | Initial oil saturation| 0.65    |
| Matrix porosity                     | 0.093   | Residual oil saturation| 0.375   |
| Matrix permeability, $10^{-3}\mu\text{m}^2$ | 0.17   | Irreducible water saturation| 0.35 |
| Thickness, m                        | 10      |                       |         |

![Sketch of the basic model](image-url)
matrix permeability in the fractured zone because of the stress sensitivity of the tight oil reservoir. The matrix permeability in the near-wellbore zone decreases to as low as $0.10 \times 10^{-3} \mu m^2$, which drops approximately 42% compared with the initial value and shows an increase in the fluid seepage resistance. Thus, the oil production rate decreases at a fast rate because of the decrease in displacement energy and the increase in fluid seepage resistance. By the end of natural depletion (three-year production), the total oil production rate drops to approximately 10 m$^3$/d from an initial production rate of 66 m$^3$/d with an average annual reduction percentage of 28.3%. In the natural depletion stage, the cumulative oil production is $2.12 \times 10^4$ m$^3$, and the oil recovery degree is 7.14%.

In the production stage of the CO$_2$ huff ‘n’ puff, the decreasing trend of the oil rate changes to periodical production (Fig. 6), and the maximum oil rate reaches close to 30 m$^3$/d. By the end of the production simulation, the cumulative oil production was $2.71 \times 10^4$ m$^3$, and the oil recovery degree was 11.44%, which was significantly higher than that of natural depletion production. Figure 10 shows the oil production and oil exchange ratio of each production cycle, where the oil exchange ratio is defined as the ratio of the produced oil volume to the injected CO$_2$ mass per cycle, as shown in Eq. (3). Oil production is highest in the first cycle, which is equivalent to the sum of the oil production in the second and third cycles. With the increase in the cycle number, the oil exchange ratio of each cycle decreases gradually. This is mainly because oil in the near-well fractured zone is gradually recovered, resulting in the reduction of the total amount of available recovered oil. Thus, the development effect of CO$_2$ huff ‘n’ puff gradually worsens as the cycle number increases.

$$\eta = \frac{V_o}{M_{CO_2}}$$

(3)

where $\eta$ is the oil exchange ratio; $V_o$ is the volume of the produced oil; and $M_{CO_2}$ is the mass of the injected CO$_2$.

**Oil saturation distribution**

The variation in the oil saturation distribution is shown in Fig. 11. Taking the first cycle as an example, the reservoir pressure gradually increases (Fig. 12a) and the solution gas is redissolved in oil as CO$_2$ injected. Therefore, the oil saturation in the near-well fractured area increased compared with that at the end of natural depletion production (Fig. 11a and Fig. 11b). During the production period, the oil saturation in the near-wellbore area gradually decreases because the oil is recovered. At the end of production, the oil in the fractured area is obviously recovered, while there is still a large amount of oil in the non-fractured area between wells. In addition, the reservoir pressure decreases with increasing cycle number (Fig. 12), indicating a declining reservoir displacement energy.

**CO$_2$ effects**

In the production stage of CO$_2$ huff ‘n’ puff, CO$_2$ injection replenishes the reservoir pressure deficit, and the oil swelling effect of CO$_2$ dissolution into the oil also helps the reservoir pressure recover. Figure 12 shows the pressure distribution of each cycle. Taking the first cycle as an example, the maximum pressure in the near-wellbore zone is 14.1 MPa. During the soaking period, the pressure distribution changes because of further gas dissolution into oil. At the end of the soaking period, the average pressure in the near-wellbore fractured area is 12.5 MPa, which is approximately 52% higher than that at the end of natural depletion.
Fig. 8  Distribution of the reservoir pressure (unit: MPa)

(a) one-year depletion  (b) two-year depletion  
(c) three-year depletion

Fig. 9  Distribution of the matrix permeability (unit: 10^{-3} \mu m^2)

(a) one-year depletion  (b) two-year depletion  
(c) three-year depletion
production (8.2 MPa). Therefore, CO₂ injection can supplement reservoir energy.

CO₂ enters the oil phase during the injection period, and the CO₂ content in the oil in the near fractured area increases (Fig. 13). A grid containing the well perforation is selected to show the oil phase viscosity and oil density variation during the CO₂ injection period of the 1st cycle, as shown in Fig. 14. From Fig. 14, there is an obvious decrease in the oil phase viscosity and density when CO₂ is injected. Thus, the interaction between CO₂ and oil reduces the oil viscosity and oil density, i.e., improving the oil’s physical properties.

Meanwhile, compared with the end of the natural depletion stage (Fig. 9c), the matrix permeability of the fractured area improves significantly as the reservoir pressure increases (Fig. 15). As shown in Fig. 16, the oil mobility in the near-wellbore area increased from \(0.015 \times 10^{-3} \text{ μm}^2/(\text{mPa·s})\) to approximately \(0.075 \times 10^{-3} \text{ μm}^2/(\text{mPa·s})\) because of the decrease in oil viscosity and the improvement in reservoir permeability, where the oil mobility is the ratio of oil phase effective permeability to its viscosity. Therefore, CO₂ injection can significantly improve the mobility of the oil phase and reduce the seepage resistance.

**Influence of CO₂ injection timing**

The timing of natural depletion production to CO₂ huff ‘n’ puff production has a direct impact on the development effect of tight oil reservoirs. Based on the model in Sect. 2, simulation models with different CO₂ injection timings are established, and three cycles of production simulation are carried out.

Figure 17 shows the oil production in the natural depletion production stage and CO₂ huff ‘n’ puff production stage. The later the CO₂ injection timing, the longer the production time, and the higher the cumulative oil production for the natural depletion production stage. However, for the puff
'n' puff production stages, the cumulative oil production decrease as the CO₂ injection timing delays, indicating that the production effect worsens.

The average reservoir pressure and oil mobility under different CO₂ injection timings are shown in Fig. 18. The earlier the CO₂ injection, the higher the reservoir pressure level, which is helpful to play the CO₂ effect. After CO₂ injection, the reservoir pressure can be effectively replenished, and oil mobility will be improved. Therefore, the development effect is better. In addition, as shown in Fig. 19, under the same injection timing, the development effect of the first cycle is the best. With the increase in the cycle number, the oil production and oil exchange ratio of each cycle decrease, indicating that the development effect worsens.

The earlier the CO₂ injection timing is, the better the development effect of the CO₂ huff 'n' puff stage. However, the earlier the CO₂ injection timing, the higher the reservoir pressure level at the end of natural depletion, and the less full the utilization of reservoir energy. For tight oil reservoirs with large formation-saturation pressure differences, natural energy should be fully utilized, and the CO₂ injection timing should not be too early. When the oil production rate
is significantly reduced, CO₂ huff ‘n’ puff production can be implemented. For the model in this paper, the formation-saturation pressure difference is approximately 9 MPa. When the CO₂ injection timing is 3 years, both the total oil recovery degree and average oil exchange ratio (Fig. 20) are at relatively high levels. Thus, CO₂ huff ‘n’ puff can be implemented after a 3-year natural depletion.

**Conclusions**

To improve the understanding of the production effect of tight oil reservoirs by CO₂ huff ‘n’ puffs after natural depletion, numerical simulation studies were carried out based on experimental results and typical reservoir parameters. The following conclusions were obtained:

1. When the tight oil reservoir is exploited by natural depletion, the oil production rate decreases rapidly with an average annual reduction percentage of 28.3% and the oil recovery degree is low (less than 10%), because the oil displacement energy decreases and the fluid seepage resistance increases with increasing production time.

2. When the tight oil reservoir is exploited by CO₂ huff ‘n’ puff after natural depletion, the reservoir energy can be supplemented and the oil mobility can be improved, resulting in a higher oil rate and recovery degree. However, the development effect gradually worsens with increasing of the cycle number.
(3) The earlier the CO₂ injection timing is, the better the development effect of CO₂ huff ‘n’ puff is, but the less full the natural energy utilization is. When carrying out the CO₂ huff ‘n’ puff, it is necessary to comprehensively consider the formation-saturation pressure difference and oil rate to determine the appropriate CO₂ injection timing.

(4) After CO₂ huff ‘n’ puff production, the oil in the fractured area is well developed, but there is still a high oil saturation in the non-fractured area between wells. The recovery degree of the tight reservoir may be further improved by CO₂ flooding or other methods.
Comments

To obtain a general understanding of tight oil reservoir development by CO₂ huff ‘n’ puff, this study neglected the heterogeneity of tight oil reservoir parameters. However, reservoir parameter variations could have a great influence on the production performance, and further studies based on detailed reservoir models should be carried out. In addition, the operation parameter optimization should be carried out for the best CO₂ huff ‘n’ puff performance. Moreover, CO₂ flooding in recovering tight oil resources can be investigated for further oil recovery enhancement.

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Declarations

Conflict of interest On behalf of all the co-authors, the corresponding author declares that there is no conflict of interest.

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