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Study on reasonable production allocation method of CO_2 assisted gravity flooding in low permeability reservoir considering pressure sensitivity effect

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ABSTRACT

There is a large amount of residual oil in the high part of the reservoir and the recovery rate is low when the high dip angle and low permeability reservoir is developed by water flooding. The use of CO_2 assisted gravity flooding can make full use of the geological characteristics of high dip angle and effectively improve the recovery degree of this kind of reservoir. However, because the influence of CO_2 on the physical properties of crude oil is much greater than the influence of water on the physical properties of crude oil, the seepage process of fluid in the process of CO_2 flooding is more complex, so it is necessary to study the reasonable production allocation optimization of CO_2 gravity flooding in low permeability reservoirs. Firstly, according to the relationship between the pressure at any point in the reservoir and the minimum miscible pressure (MMP), the miscible and immiscible models of CO_2 gravity flooding in low permeability reservoirs considering the pressure sensitivity effect are established respectively. Secondly, Python is used to solve the model, and the influence of pressure sensitivity coefficient, formation dip angle, injection- production well spacing and gas injection speed on reservoir allocation is analyzed. Finally, combined with the existing work system method and the production increase multiple method, compared with the calculation results of this model, the tNavigtor software is used to predict the recovery rate of the three methods. The results show that this method has a good development effect on the reasonable production allocation of the reservoir, and the recovery rate of the reservoir is relatively high. The research results have a good reference for the development of this kind of low permeability reservoir.

Keywords: high dip and low permeability reservoir, CO_2 displacement, filtration theory, pressure sensitivity effect, reasonable production allocation

NONMENCLATURE

Abbreviations	
MMP	Minimum miscibility pressure
Symbols	
q	the oil production of oil well (m^3/d)
K	formation permeability (mD)
B	the stratum width (m)
h	the thickness of stratum (m)
μ_m	the fluid viscosity in the miscible region (mPa·s)
P	formation pressure (MPa)
ρ_m	the fluid density in the miscible region ($kg \cdot m^{-3}$)
g	gravity coefficient (N/kg)
θ	formation dip angle (°)
λ_m	the starting pressure gradient of the fluid in the miscible region (MPa/m)
P_{mm}	the minimum miscibility pressure (MPa)
P_{iwf}	the bottom hole pressure of the gas injection well (MPa)
X_m	the length of the miscibility zone (m)
μ_g	the viscosity of CO_2 gas (mPa·s)

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C	the concentration of CO_2 (decimal)
μ_o	the viscosity of oil (mPa·s)
ρ_g	the density of CO_2 (kg·m^{-3})
ρ_o	the density of oil (kg·m^{-3})
v	seepage velocity (m·s^{-1})
ξ	the velocity coefficient of particle capture (m^{-1})
D	the diffusion coefficient of CO_2 in crude oil (m^2/s)
β	the adsorption velocity coefficient of particles on the rock surface (s^{-1})
K_o	original formation permeability (mD)
M	pressure-sensitive coefficient (MPa^{-1})
P_i	original formation pressure (MPa)
a	positive real numbers (decimal)
b	positive real numbers (decimal)
k_{ro}	the relative permeability of oil phase (decimal)
μ_{io}	the viscosity of oil phase in immiscible region (mPa·s)
ρ_{io}	the oil phase density in immiscible region (kg·m^{-3})
λ_{io}	the starting pressure gradient of oil phase in immiscible region (MPa/m)
φ	porosity (decimal)
S_o	oil saturation (decimal)
k_{rg}	the relative permeability of gas phase (decimal)
λ_g	the starting pressure gradient of gas phase in immiscible region (MPa/m)
B_g	the volume coefficient of CO_2 (m^3/m^3)
B_o	the volume coefficient of oil (m^3/m^3)
R_s	the solubility of CO_2 in oil (m^3/m^3)
S_g	gas saturation (decimal)
S_{or}	residual oil saturation (decimal)
Y_g	the proportion of CO_2 component in oil phase (decimal)
α	a constant related to temperature and pressure (decimal)
F_g	the ratio of the volume of CO_2 under standard conditions to the volume under reservoir conditions (m^3/m^3)
F_o	the ratio of the volume of oil under reservoir temperature and 0.1MPa pressure to the volume under reservoir volume (m^3/m^3)
$Q(t)$	the total flow through the seepage section (m^3)
X_{im}	the length of the immiscible zone (m)
L	the injection-production well spacing (m)

1. INTRODUCTION

With the gradual increase of the contradiction between supply and demand of oil and gas resources, the development of low permeability reservoirs has become the only way. Low permeability reservoir resources account for a large proportion of the total oil and gas resources. More than 40 countries in the world have evaluated the reserves of low permeability reservoirs, and the results show that the recoverable amount is about 483×108t [1]. The proportion of low permeability oil and gas resources in China has reached 49 % of the total oil and gas resources, of which the proven reserves are about 160×108t [2,3]. In the development of water flooding in high dip and low permeability fault block reservoirs, there is a large amount of residual oil in the high part and corner of the reservoir, and the recovery rate is low [4]. The top gas injection flooding is an effective development method for this reservoir. Compared with other gases, CO_2 is easier to dissolve with crude oil, and its critical temperature and pressure are also lower [5]. Its physical and chemical properties determine that its displacement mechanism is mainly to reduce the interfacial tension of crude oil and reduce the displacement resistance [6]; reduce the viscosity of crude oil [7]; expanding the volume of crude oil [8]; extraction and vaporization of light hydrocarbons in crude oil [9]; pressure drop causes dissolved gas flooding [10]; acid solution plugging effect, improve the injection capacity[11].

Crude oil production allocation is the equilibrium point of technical policy and management [12] and the scientific of production allocation method will be directly related to the effect of oilfield development [13], Scholars at home and abroad have done a lot of work in the study of production allocation methods [14-18]. However, most of the previous studies only considered the influence of single factor on crude oil production allocation, and the influence of multiple factors such as pressure sensitivity effect, starting pressure gradient and fluid physical properties on production allocation is almost blank.

In this paper, on the basis of previous studies, considering the change of fluid physical properties after CO_2 injection, and considering the influence of fluid physical properties on the nonlinear seepage of low permeability reservoirs, a mathematical model of CO_2

gravity flooding in low permeability reservoirs considering pressure sensitive effect is established. At the same time, the trial algorithm and iterative method are used to solve the model, and the corresponding chart is drawn to analyze the influence of pressure sensitivity coefficient, formation dip angle, injection-production well spacing and gas injection speed on the reasonable production allocation of the reservoir. According to the actual data of A reservoir, the production of water flooding to CO_2 flooding in the reservoir is optimized.

2. ESTABLISHMENT OF THE MODEL

In the process of CO_2 gravity flooding in actual reservoir, the formation pressure from injection well to production well is gradually reduced. When the minimum miscible pressure of CO_2 is between the bottom hole flow pressure of injection well and the bottom hole flow pressure of production well, the seepage of crude oil and CO_2 in the formation will be divided into CO_2 miscible zone and CO_2 immiscible zone, as shown in figure 1.

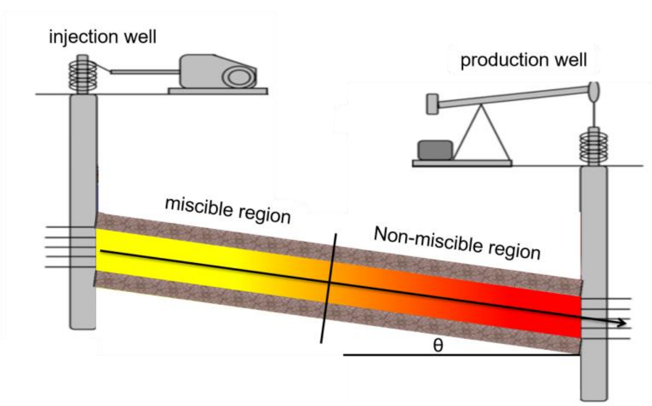

Fig. 1. CO_2 gravity drive seepage model

2.1 Assumed condition

In order to establish the seepage model of CO_2 gravity drive in low permeability reservoir, according to the actual characteristics of CO_2 gravity drive reservoir, the following assumptions are made.

(1) The reservoir is an inclined, homogeneous and equal-thick banded reservoir with length of X, width of B, thickness of h and dip angle of θ .

(2) The reservoir is a low permeability reservoir, considering the influence of starting pressure gradient and pressure sensitivity effect.

(3) There are two phases of oil and gas in the reservoir, considering the influence of CO_2 on the viscosity and density of crude oil.

(4) The minimum miscible pressure is between the bottom hole flow pressure of gas injection well and production well, and the fluid seepage area is composed of miscible zone and immiscible zone.

(5) There are two phases of oil and gas in the reservoir, considering the influence of CO_2 on the viscosity and density of crude oil.

2.2 CO_2 miscible zone model

When the formation pressure is greater than the minimum miscible pressure, CO_2 and crude oil form a miscible phase, and the fluid seepage in the miscible zone is a single-phase seepage. At the same time, considering the influence of starting pressure gradient and gravity, the Darcy formula is modified, and the flow rate through any section is:

$$q=\frac{KBh}{\mu_{\mathrm{m}}}\left(\frac{dP}{dX}+\rho_m g\sin\theta-\lambda_m\right) \tag{1}$$

where q is the oil production of oil well, m^3/d; K is formation permeability, mD; B is the stratum width, m; h is the thickness of stratum, m; μ_m is the fluid viscosity in the miscible region, mPa·s; P is formation pressure, MPa; ρ_m is the fluid density in the miscible region, kg/m^3; g is the gravity coefficient, N/kg; θ is the formation dip angle, °; λ_m is the starting pressure gradient of the fluid in the miscible region, MPa/m.

Substitute the boundary conditions: when X=0, P= P_{iwf}; when X= X_m, P= P_{mm}, and integral, get:

$$p_{\mathrm{mm}}-p_{iwf}=\int_0^{X_m}\left(\frac{q\mu_{\mathrm{m}}}{KBh}+\rho_m g\sin\theta-\lambda_m\right)dx \tag{2}$$

where P_{mm} is the minimum miscibility pressure, MPa; P_{iwf} is the bottom hole pressure of the gas injection well, MPa; X_m is the length of the miscibility zone, m.

The fluid density and viscosity in the miscible region can be calculated by the following formula:

$$\mu_{\mathrm{m}}=\mu_{\mathrm{g}}C+\mu_o(1-C) \tag{3a}$$

$$\rho_{\mathrm{m}}=\rho_{\mathrm{g}}C+\rho_o(1-C) \tag{3b}$$

where μ_g is the viscosity of CO_2 gas, mPa·s; C is the concentration of CO_2, decimal; μ_o is crude oil viscosity, mPa·s; ρ_g is the density of CO_2, kg/m^3; ρ_o is crude oil density, kg/m^3.

In the CO_2 miscible region, the concentration of CO_2 is different at different positions. The viscosity and density of the fluid in the miscible region are required. The concentration of CO_2 in the fluid needs to be obtained first. The distribution law can be characterized by the following formula [19]:

$$C(x,t)=\frac{1}{2}e^{\frac{vx}{2D}}\cdot e^{-\xi x}\times(erf\,\frac{x-\sqrt{u^2+4\beta D}\cdot t}{2\sqrt{Dt}} +erf\,\frac{x+\sqrt{u^2+4\beta D}\cdot t}{2\sqrt{Dt}}) \tag{4}$$

where v is seepage velocity, m/s; ξ is the velocity coefficient of particle capture, m^{-1} D is the diffusion coefficient of CO_2 in crude oil, m^2/s; β is the adsorption velocity coefficient of particles on the rock surface

The permeability calculation formula considering the pressure-sensitive effect [20,21]:

$$K=K_0e^{-M(P_i-P)} \tag{5}$$

where K_o is original formation permeability, mD; M is the pressure-sensitive coefficient, MPa^{-1}; P_i is original formation pressure, MPa.

The calculation formula of variable start-up pressure gradient considering pressure-sensitive effect [22]:

$$\lambda_m=a\left(\frac{K_0}{\mu_m}\right)^{-b}e^{bM(P_i-P)} \tag{6}$$

where a, b are positive real numbers.

Formula (1) ~ (6) is the mathematical model of the miscible phase of CO_2 gravity flooding in low permeability reservoirs considering the pressure-sensitive effect.

2.3 CO_2 immiscible zone model

The area where the formation pressure is less than the minimum miscible pressure is called the CO_2 immiscible zone, and the fluid seepage in this area is oil-gas two-phase seepage. Considering the influence of CO_2 dissolution on the physical properties of crude oil, the starting pressure gradient of oil phase and the pressure sensitivity effect, the basic differential equation of one-dimensional seepage of CO_2-crude oil two-phase non-Darcy gravity flooding phase is as follows: get:

$$\frac{\partial}{\partial x}\left[\frac{KK_{ro}}{\mu_{io}}(\frac{\partial p}{\partial x}+\rho_{io}g\sin\theta-\lambda_{io})\right]=\varphi\frac{\partial S_o}{\partial t} \tag{7a}$$

$$\frac{\partial}{\partial x}\left[\begin{array}{l}\frac{KK_{rg}}{\mu_g B_g}(\frac{\partial p}{\partial x}+\rho_g g\sin\theta-\lambda_g)+\\ \frac{R_s KK_{ro}}{\mu_{io}B_o}(\frac{\partial p}{\partial x}+\rho_{io}g\sin\theta-\lambda_{io})\end{array}\right]= \varphi\frac{\partial}{\partial t}(\frac{1-S_o}{B_g}+\frac{S_oR_s}{B_o}) \tag{7b}$$

where K_{ro} is the relative permeability of oil phase, decimal; μ_{io} is the viscosity of oil phase in immiscible region, mPa·s; ρ_{io} is the oil phase density in immiscible region, kg/m^3; λ_{io} is the starting pressure gradient of oil phase in immiscible region, MPa/m; φ is porosity, decimal; S_o is oil saturation, decimal. K_{rg} is the relative permeability of gas phase, decimal; λ_g is the gas phase start-up pressure gradient in the immiscible region, MPa/m; B_g is the volume coefficient of CO_2, m^3/m^3; B_o is the volume coefficient of crude oil, m^3/m^3; R_s is the solubility of CO_2 in crude oil, m^3/m^3.

The flow through any section is:

$$q=KBh[\frac{K_{rg}}{\mu_g}(\frac{\Delta P}{\Delta x}+\rho_g g\sin\theta-\lambda_g)+ \frac{K_{ro}}{\mu_{io}}(\frac{\Delta P}{\Delta x}+\rho_{io}g\sin\theta-\lambda_{io})] \tag{8}$$

The pressure difference is:

$$\Delta P=\frac{\Delta x}{\frac{K_{rg}}{\mu_{ig}}+\frac{K_{ro}}{\mu_{io}}}[\frac{K_{rg}}{\mu_{ig}}(\rho_{ig}g\sin\theta-\lambda_{ig}) +\frac{K_{ro}}{\mu_{io}}(\rho_{io}g\sin\theta-\lambda_{io})-\frac{q}{KBh}] \tag{9}$$

The relative permeability of oil and gas phase is a function of gas saturation, which can be obtained by relative permeability curve fitting:

$$K_{rg}=0.06(\frac{S_g}{1-S_{or}})^{2.39} \tag{10a}$$

$$K_{ro}=1.23(\frac{S_g}{1-S_{or}})^{3.353} \tag{10b}$$

where S_g is gas saturation, decimal; S_{or} is the residual oil saturation, decimal.

CO_2 is constantly dissolved in crude oil, and the physical properties of the fluid in the formation are constantly changing. The formula (11) can be used to correct the viscosity and density of the oil phase in the CO_2 immiscible zone [23]:

$$\mu_{io}=\mu_o^{1-Y_g}\times\mu_g^{Y_g} \tag{11a}$$

$$\rho_{io}=\rho_o^{1-Y_g}\times\rho_g^{Y_g} \tag{11b}$$

where Y_g is the proportion of CO_2 component in oil phase, decimal.

The formula (12) can be used to correct the proportion of CO_2 component in oil phase [24]:

$$Y_g=\frac{1}{\alpha F_g/(5.618F_oR_s)+1} \tag{12}$$

where α is a constant related to temperature and pressure, decimal; F_g is the ratio of the volume of CO_2

under standard conditions to the volume under reservoir conditions, m^3/m^3; F_o is the ratio of the volume of crude oil under reservoir temperature and 0.1MPa pressure to the volume under reservoir volume, m^3/m^3.

The starting pressure gradient of oil phase and gas phase considering pressure sensitivity effect in immiscible region:

$$\lambda_{\mathrm{io}} = a\left(\frac{K}{\mu_{\mathrm{io}}}\right)^{-b} e^{bM(P_i - P)} \tag{13a}$$

$$\lambda_{\mathrm{g}} = a\left(\frac{K}{\mu_{g}}\right)^{-b} e^{bM(P_i - P)} \tag{13b}$$

Formula (7) ~ (13) is the mathematical model of immiscible part of CO_2 gravity flooding in low permeability reservoirs considering pressure-sensitive effect.

3. SOLUTION AND ANALYSIS OF THE MODEL

3.1 CO_2 miscible zone solution method

Considering the pressure-sensitive effect, the formation permeability and starting pressure gradient of the fluid affecting the flow of CO_2 gravity drive vary with the change of pressure, and the pressure gradient at each point is not constant. Therefore, the fluid seepage in the miscible region considering the pressure-sensitive effect needs to be calculated in sections, and the seepage parameters (permeability, viscosity, density and starting pressure gradient) of each section need to be obtained in advance. However, permeability and start-up pressure gradient are functions of pressure, and pressure is an unknown number in calculation, so CO_2 gravity drive needs to be calculated by trial algorithm and iterative method. Because the pressure at both ends of the miscible region is known, the iterative calculation is performed with length increment. The steps are as follows:

(1) Taking the bottom hole flowing pressure P_{iwf} of the gas injection well as the starting point, an appropriate pressure drop ΔP is taken as the calculated pressure interval.

(2) Assuming that a corresponding ΔP corresponds to the corresponding ΔX, according to Eq. (4) to determine the CO_2 concentration distribution in this section.

(3) Calculate the formation pressure P_I and CO_2 mole fraction C_I at the right end of the section, and determine the seepage parameters (formation permeability, fluid viscosity, fluid density and starting pressure gradient, etc.) under the P_I and C_I according to equation (3), (5) and(6).

(4) According to the formula (1), the length ΔX_j corresponding to ΔP is calculated.

(5) Comparing the ΔX_j calculated in step (4) with the ΔX assumed in step (2), both of which exceed the allowable error range, the new ΔX is used as the assumed value, and the calculation from (2) to (4) is repeated, so that the error between the calculated ΔX_j and ΔX is within the allowable error range.

(6) Calculate the displacement distance X_I and formation pressure P_I corresponding to the right end of this section.

$$X_I = \sum_{j=1}^{I} X_j \tag{14}$$

$$P_I = P_{\mathrm{iwf}} - \mathrm{I} \triangle P \tag{15}$$

(7) Taking the pressure at X_I as the starting point, repeat steps (2) to (6), calculate the length displacement distance X_{I+1} and formation pressure P_{I+1} in the next step, until the formation pressure is equal to or less than the minimum miscibility pressure, and obtain the length of the miscibility zone X_{mm}.

3.2 CO_2 immiscible zone model

The relative permeability of oil phase and CO_2 gas phase in CO_2 immiscible zone is a function of gas saturation, and the formation permeability is a function of pressure. Therefore, in order to solve the CO_2 immiscible flooding model, the saturation distribution and pressure distribution in the area must be solved first. According to the Buckley-Levertt displacement theory, the equation of motion of the front edge of equal saturation is:

$$X - X_0 = \frac{1}{\varphi A}\frac{df_g(S_{\mathrm{g}})}{dS_g} Q(t) \tag{16}$$

where Q(t) is the total flow through the seepage section, m^3.

Because the injection-production well spacing is known, the length of the miscible zone is solved according to the seepage of the CO_2 miscible zone, and the length of the immiscible zone is:

$$X_{\mathrm{im}} = \frac{L}{\cos\theta} - X_{\mathrm{mm}} \tag{17}$$

where X_{im} is the length of immiscible region, m; L is the injection-production well spacing, m.

The immiscible region is divided into n equal parts. Substituting X=X_{I+1}, X= X_I into Eq. (16) and subtracting, we get:

$$\triangle X_{\mathrm{I}} = \frac{Q(t)}{\varphi A}\left\{\frac{df_g[S_{g(\mathrm{I}+1)}]}{dS_{g(\mathrm{I}+1)}} - \frac{df_g[S_{g(\mathrm{I})}]}{dS_{g(\mathrm{I})}}\right\} \tag{18}$$

Because the length of the two ends of the immiscible zone is known, the iterative calculation is carried out with the pressure increment pair (9). The steps are as follows:

(1) Select the appropriate displacement length ΔX with the minimum miscible pressure X_{mm} pressure P_{mm} as the starting point.

(2) Estimate the ΔP corresponding to a corresponding displacement length ΔX .

(3) According to formula (10) and (16), the relative permeability of oil phase and CO_2 phase in this section is calculated. Combined with formula (5), formula (11) and (13), the formation permeability, fluid density, fluid viscosity and starting pressure gradient of oil phase and CO_2 phase in this section are calculated.

(4) The pressure change ΔP_j of this section is calculated according to Eq. (9)

(5) Comparing the estimated ΔP and ΔP_j , if the error between the two is within the allowable error range, the calculated value is used as a new estimate, and steps (2) to (4) are repeated until the error between the two is within the allowable range.

(6) Calculate the displacement distance X_{I} and pressure P_{I} of the right end of the segment.

$$X - X_0 = \frac{1}{\varphi A}\frac{df_g(S_g)}{dS_g}Q(t) \tag{19}$$

$$X - X_0 = \frac{1}{\varphi A}\frac{df_g(S_g)}{dS_g}Q(t) \tag{20}$$

(7) Repeat steps (2) to (6) with the pressure P_{I} at X_{I} as the starting point. Calculate the length of the next section $X_{\mathrm{I+1}}$ and the pressure $P_{\mathrm{I+1}}$ until X_{I} is equal to or greater than $L/\cos\theta$, and output P_{wf}.

3.3 Parameter sensitivity analysis

3.3.1 Pressure-sensitive coefficient

Keeping the injection-production well spacing, gas injection volume, formation dip angle and other parameters unchanged, only the pressure sensitivity coefficient is changed, and the reasonable production allocation of different bottom hole flow pressure is calculated when the pressure sensitivity coefficient is different, and the map is drawn, as shown in Figure 2.From the diagram, it can be seen that with the increase of pressure sensitivity coefficient, the bottom hole flowing pressure-reasonable production allocation curve moves downward ; at the same time, it can be found that the greater the bottom hole flow pressure, the smaller the influence of the pressure sensitivity coefficient on the reasonable production allocation. This is because the pressure sensitivity coefficient represents the degree of damage to the reservoir caused by the change of formation pressure. That is to say, when the formation pressure is the same, the larger the pressure sensitivity coefficient is, the greater the resistance of the fluid seepage in the reservoir is, which leads to the smaller the reasonable production of the reservoir. At the same time, it also shows that increasing the bottom hole flow pressure can effectively reduce the damage of the pressure effect on the reservoir. When the pressure sensitivity coefficient is 0, that is, without considering the influence of pressure sensitivity effect, the reasonable production allocation of the reservoir is relatively high.

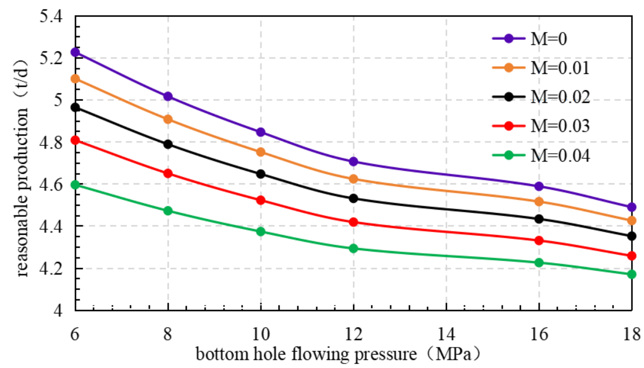

Fig. 2. The influence of pressure-sensitive coefficient on reasonable production allocation

3.3.2 Stratigraphic dip

Keeping the parameters such as pressure sensitivity coefficient, injection-production well spacing and gas injection velocity unchanged, only changing the size of formation dip angle, the reasonable production allocation of different bottom hole flow pressure under different formation dip angle conditions is calculated, and the chart is drawn, as shown in figure 3.It can be seen from the figure that as the formation dip angle increases, the bottom hole flowing pressure-reasonable production curve moves upward, indicating that under the same bottom hole flowing pressure conditions, the reasonable production of the reservoir increases with the increase of the formation dip angle. This is because the greater the dip angle of the formation, the greater the gravitational potential energy of the fluid, and for gravity-driven reservoirs, the gravitational potential energy can provide power for fluid seepage, that is, when under the same displacement pressure difference, the greater the dip angle of the formation, the easier the fluid flows, and the greater the seepage velocity, resulting in a reasonable allocation of reservoir production becomes larger.

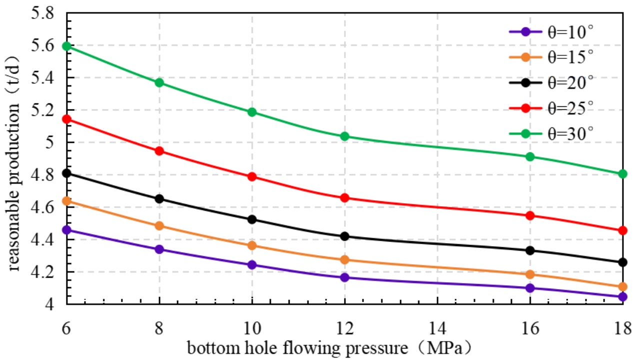

Fig. 3. The influence of formation dip angle on reasonable production allocation

3.3.3 Injection-production well spacing

Keep the parameters such as pressure sensitivity coefficient, formation dip angle and gas injection velocity unchanged, only change the size of injection-production well spacing, calculate the reasonable production allocation of different bottom hole flowing pressure under different injection-production well spacing conditions, and draw the map, as shown in Fig.4. From the diagram, it can be seen that with the increase of injection-production well spacing, the bottom hole flowing pressure-reasonable production allocation curve moves downward, indicating that under the same bottom hole flowing pressure, the reasonable production allocation of the reservoir decreases with the increase of injection-production well spacing. This is because the larger the injection-production well spacing, the greater the energy consumed by the fluid in the formation seepage, resulting in the smaller the reasonable allocation of the reservoir.

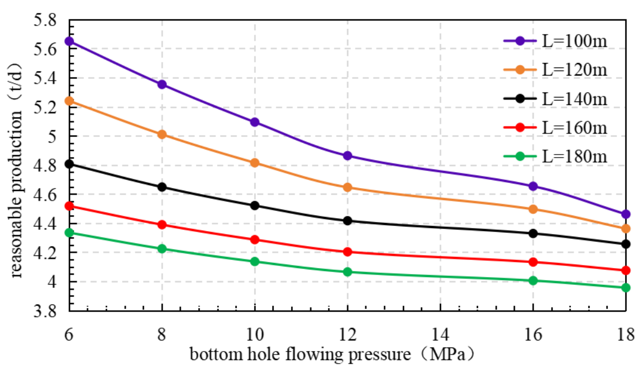

Fig. 4. The influence of injection-production well spacing on reasonable production allocation

3.3.4 Gas injection rate

Keeping the parameters such as pressure sensitivity coefficient, formation dip angle and injection-production well spacing unchanged, only changing the size of gas injection speed, the reasonable production allocation of different bottom hole flow pressure under different gas injection speed conditions is calculated, and the chart is drawn, as shown in figure 5.From the diagram, it can be seen that with the increase of gas injection speed, the bottom hole flow pressure-reasonable production allocation curve moves upward, indicating that under the same bottom hole flow pressure, the reasonable production allocation of the reservoir increases with the increase of gas injection speed, and the increase of reasonable production allocation decreases with the increase of gas injection speed.

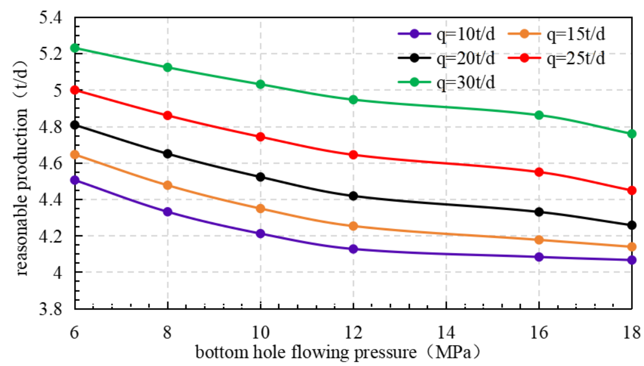

Fig. 5. The influence of gas injection rate on reasonable production allocation

4. APPLYCATION

Taking A oilfield as an example, the reasonable production allocation after water flooding to CO_2 flooding is calculated by using the established model. The formation dip angle of this block is about 20°, the buried depth is 2500m, the porosity is 13.8%, the permeability is 3.4mD, the temperature is 85℃, the original formation pressure is 24.2MPa, the current pressure is 14.7MPa, and the well spacing is 140m. Through swelling, MMP, long core displacement and other experiments, under the original temperature and pressure conditions, the viscosity of crude oil is 2.752 mPa·s, and the viscosity reduction of crude oil is 66.6% after CO_2 injection. The minimum miscibility pressure of CO_2 and crude oil is 25MPa, and the pressure sensitivity coefficient is 0.03. The volume of CO_2 in the current reservoir is 2.68m^3/d.

Table 1 Block statistics of increasing production multiples from water flooding to CO_2 flooding

Reservoir name	porosity/ (%)	permeability/ (mD)	crude oil density/ ($g \cdot cm^{-3}$)	crude oil viscosity/ (mPa • s)	Water drive production/ (m^3/d)	CO_2 Flooding Production/ (m^3/d)	production increase multiple/ (decimal)
Weyburn	12	15	0.887	4.700	2782.04	4479.00	1.61
Dollaride Devonial	17	9	0.830	0.400	119.41	192.00	1.61
Wertz tensleep	11	15	0.850	1.300	795.13	1701.00	2.14
Means San andres	9	20	0.880	6.000	1589.80	2941.00	1.85
North Cross	13	44	0.850	1.500	222.53	369.00	1.66
Slaughter Estate	12	8	0.870	2.000	33.38	66.10	1.98
Sinopec East China Oil	14	23	0.883	12.830	47.71	76.80	1.61
Pubei Block of Daqing	17.8	110	0.803	0.400	422.30	565.00	1.34
zhongyuan oil fields	27.2	245	0.748	2.020	4.76	14.60	3.07
Block Shu101 of Daqing	10	1	0.787	3.600	32.92	49.70	1.51
Hei 59 block of Jilin	10	5	0.769	1.970	50.07	76.60	1.53
Hei 79 block of Jilin	18	20	0.855	2.000	64.38	92.10	1.43

The reservoir engineering method, the current production system of the reservoir and the method of increasing production multiple are used to reasonably allocate the production in the work area. At the same time, tNavigator software is used to predict. The results are shown in Table 2. According to the method in this paper, the reasonable production allocation of the work area is determined to be 425 t / d, and the predicted recovery rate is high, up to 44.2 %, which indicates that the calculation method established in this paper can be well applied to the actual production of the oilfield.

Table 2 Analysis of reasonable production allocation

method	rationing production/($t \cdot d^{-1}$)	recovery ratio/(%)
Method of this article	425	44.2
The current production system	315	37.1
production increase multiple	450	40.6

5. CONCLUSION

(1) Based on the interaction between CO_2 and crude oil, combined with the complex seepage environment of low permeability reservoirs, a mathematical model of CO_2 gravity flooding considering the effect of pressure sensitivity and starting pressure gradient is established.

(2) Python programming software is used to solve the mathematical model, and different parameters are set to analyze the influence of four parameters, pressure sensitivity coefficient, formation dip angle, injection production well spacing and gas injection speed, on the reasonable production allocation of the reservoir. The larger the formation dip angle and gas injection speed, the larger the reasonable production allocation. The larger the pressure sensitivity coefficient and the injection-production well spacing, the smaller the reasonable production allocation.

(3) According to the actual parameters of A oilfield, the method of this paper, the current production system of the reservoir and the method of increasing production multiples are used to allocate the production in the work area. At the same time, tNavigtor software is used to predict the recovery rate. The results show that the production system of 425t/d is determined according to the method of this paper, and the recovery rate of the reservoir is high, up to 44.2 %.

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DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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