Numerical simulation and field application of biological nano-technology in the low- and medium-permeability reservoirs of an offshore oilfield

Ping Gao · Qing Feng · Xianchao Chen · Shengsheng Li · Yanni Sun · Jiang Li · Jingchao Zhou · Feng Qian

Received: 21 February 2022 / Accepted: 24 May 2022 / Published online: 16 June 2022
© The Author(s) 2022

Abstract
As a result of deep burial depth, small pore throat, poor connectivity between pores, different clay mineral contents in reservoirs, and strong reservoir sensitivity, injection wells often have problems such as rapidly increasing water-injection pressure and insufficient water-injection quantity in the process of water-injection development. The main measures used to solve the difficulties of water injection in low-permeability reservoirs include fracturing, acidizing, and surfactant depressurization and injection increase, all of which have some disadvantages of high cost and environmental damage. In recent years, depressurization and injection-increase environment-safe bio-nano-materials have been introduced into low-permeability reservoirs and have achieved good application results in China. On the other hand, although there have been many researches on EOR (enhanced oil recovery) of nano-materials, the numerical simulation field of nano-depressurization and injection-augmenting technology is still a blank that the wettability mechanism of nano-materials and EOR nano-materials used in bio-nano-depressurization and injection-augmenting technology are almost completely opposite, and the influence of adsorption on formation is almost completely opposite. The adsorption of nanoparticles in other EOR studies will reduce the porosity and make the reservoir more hydrophilic. Nanoparticles used in biological nano-technology will produce hydrophobic film near the well, which will reduce the seepage resistance through the slip of water phase. In this study, a set of water flooding model of numerical simulation technology for depressurization and injection-augmenting of biological nano-materials considering adsorption characteristics and reservoir physical properties was established, the sensitivity analysis of key injection parameters was carried out, and the application effect prediction chart of biological nano-technology was drawn, and the model and prediction chart were verified by real oilfield data. As far as we know, this is the first numerical simulation study on biological nano-technology that has been applied in oil fields.

Keywords Offshore low- and medium-permeability reservoir · Biological nano-technology · Numerical simulation · Parameter optimization · Field application

Introduction
Due to long-term exploitation and expanding oil demand, many onshore oil fields in China have begun to turn to large-scale exploration and development of gas reservoirs (Anees et al. 2022a, b). At the same time, many offshore oilfields are gradually developing medium- and low-permeability reservoirs that permeability less than 50mD and greater than 5mD. However, in the process of water-injection development, offshore low-permeability reservoirs are prone to problems such as rapidly increased water-injection pressure, insufficient water-injection capacity, and a rapid decline of oil-well production. This is the result of factors such as deep burial, small pore throat, poor connectivity between
pores, different clay mineral contents, and strong reservoir sensitivity (Anderson et al. 2010; Cao et al. 2014; Chen et al. 2016a, b; Moghadasi et al. 2019; Wang et al. 2020, 2021).

At present, solutions to the difficulty of water injection in low-permeability reservoirs include fracturing, acidification, and surfactant depressurization and injection increase (Zhou et al. 2004; Chen et al. 2016a, b; Silei et al. 2019; Liu et al. 2020; Qu et al. 2021; Kalam et al. 2021; Omari et al. 2021; Motta et al. 2021). Although these methods have helped overcome some of the problems of water-injection development, they still have certain disadvantages of high cost and environmental damage (Chen et al. 2016b; Yang 2017; Zhao et al. 2017; Feng et al. 2019; Lei et al. 2019; Ren et al. 2021). By contrast, the nano-materials can expand the effective radius of formation pores and have a super-hydrophobic effect, which can reduce injection resistance and improve water-phase permeability (Di et al. 2015; Qu et al. 2021). Additionally, they have anti-swelling properties, can isolate contact between injected water and clay minerals on the rock surface, and can reduce the blockage of formation pores caused by particle migration, allowing them to achieve the effect of depressurization and injection increase (Gu et al. 2007; Alaskar 2013; Kazemzadeh et al. 2019; Liu et al. 2020; Qu et al. 2021; Davin et al. 2022).

In recent years, some new type nano-materials of depressurization and injection increase have been introduced into low-permeability reservoirs and has achieved good application results (Zhou et al. 2004; Chen et al. 2016a, b; Silei et al. 2018; Dai et al. 2018; Zhai et al. 2019; Ding et al. 2020; Li 2021). After injecting nano-polysilicon, nanoparticles are coated on the surface of clay, which can prevent the immersion of injected water and prevent clay from swelling, thus achieving the purpose of reducing well head pressure and increasing injection, it has achieved good application results in Wuqi oilfield (Li 2014). The recent research found that the water-based nano-polysilicon depressurization and injection-augmenting agent manufactured by in situ surface modification technology has a good wettability change effect, and its practical application effect is good (Liu et al. 2017, 2018). Using experiments such as nano-agent stability, a China researcher optimized the water-based nano-agent SL-3 to make it suitable for an ultra-low-permeability reservoir in the Shishen A area; the three wells this was applied to were successful and had good results for depressurization and injection increase (Yi 2017). In addition, adding surfactant to nanoparticle solution can greatly improve the permeability of water phase. The field application results of three wells showed that the average pressure-reduction rate was 30.2%, the average daily water injection was increased by 84.4%, and the average validity period was 195 days, thus meeting the needs of long-term depressurization and injection increase for water-injection wells in offshore oil fields (Xu et al. 2019). In Cupiagua oilfield, Castilla oilfield, and Chipimene oilfield, nanofluids have successfully improved the reservoirs damaged by precipitation (Adil et al. 2016; Zawrah et al. 2016; Franco-Aguirre et al. 2018).

The transportation process of nanoparticles underground is very complicated, which is related to concentration, pH, permeability, flow velocity, particle (such as size, size distribution, shape, surface charge, and so on) (Alaskar et al. 2012; Fadili et al. 2022). When nanoparticles move in the reservoir, they are captured and absorbed into the pores (Irfan et al. 2019). Therefore, it is important to consider the net loss rate of nanoparticles, which is given by Ju et al. after modification, the model studies the effects of water saturation, nanoparticle concentration, porosity, and permeability on the flow of nanoparticles in porous media (Ju et al. 2002; Ju and Fan 2009). Chen et al. (2016a, b) established a drag reduction model for hydrophobic nanoparticles, which was numerically simulated by IMPES method, and predicted the changes of core surface wettability and well displacement. In heterogeneous porous media, Salama model confirmed the deposition of nanoparticles by considering the filtration theory (Salama et al. 2015; Abdelfatah et al. 2017). Agista (2017) established a modified linear adsorption model, which can accurately simulate the adsorption process of nanoparticles, but can’t well simulate the desorption behavior caused by scouring in the subsequent water-injection process. El-Amin et al. (2015) used a dimensional analysis method based on a nanoparticle transport model to investigate the effect of each parameter used in the model governing equations. After performing dimension analysis, different dimensional numbers can be introduced into the system, such as the Darcy number, the Capillary number, and the Bond number (El-Amin et al. 2015; Irfan et al. 2019).

In oil and gas reservoirs, production is closely related to mineral composition, fracture, permeability, and porosity that are characterized by geological models in the field numerical simulation, and there are also many excellent treatment methods (Thai Ba et al. 2020; Liu et al. 2020; Thanh and Sugai 2021; Ashraf et al. 2021; Ma et al. 2021; Shen et al. 2022). There are many and perfect numerical simulation studies on these aspects of conventional chemical flooding (Yadali Jamaloei 2011; Ansah et al. 2020; Li et al. 2021a; Ma et al. 2021; Shen et al. 2022). There is, however, a lack of research on the numerical simulation of depressurization and injection-increase technology, especially biological nano-depressurization and injection-increase technology. The difference between nano-technology of decreasing pressure and increasing injection and EOR (enhanced oil recovery) numerical simulation of nano-materials lies in that biotechnology increases the formation seepage channel and reduces the seepage resistance through the adsorption of hydrophobic nano-materials in the formation, while conventional nano-materials of EOR mostly use hydrophilic nanoparticles and seldom consider the adsorption of nanoparticles in the formation and the change of formation.
physical properties. In this research, a new numerical simulation model of depressurization and injection-augmenting is established for the biological nano-technology which has been successfully applied in the field, and the sensitivity analysis of the influencing factors of its application effect is carried out, and the established model is verified by the actual production data. Compared with the previous EOR study of nanoparticles, this study not only considers the cumulative oil increase, but also pays attention to the well head pressure of injection well.

**Multiphase and multicomponent mathematical model for depressurization and injection-augmenting of biological nano-technology**

**Mechanism of depressurization and injection-augmenting of biological nano-solution**

In the field of petroleum engineering, there are two methods to depressurization and injection-augmenting: one is to treat the formation such as acidification and fracturing to enlarge the pore throat of the formation and increase the seepage area; the other is to reduce the friction between pore throat and seepage fluid (Li et al. 2021b).

Before nanoparticle injection, acid will be used to perform limited plug removal around the bottom hole. After nanoparticles are injected into the formation, they will be adsorbed to the formation to form a thin (nanometer thickness) hydrophobic film (Lu et al. 2003; Lashari and Ganat 2020; Foroozesh and Kumar 2020), as shown in Fig. 1(a). In the process of nanoparticles adsorbing to the wall to form a hydrophobic nanoparticle film, the water film on the rock wall will fall off, which will lead to the increase in seepage channels, thus also leading to the increase in porosity and permeability (Liu et al. 2017; Li et al. 2021b) to make the treatment more convenient, the two methods are combined here to treat the porosity increase, which can be expressed as follows:

\[
\phi = \phi_0 + c_{np} \left( \rho_s - \rho_{np} \right)
\]  

(1)

where \( \phi \) is the porosity after biological nano-technology; \( \phi_0 \) is original porosity; \( \rho_s \) is the density of inorganic scale; \( \rho_{np} \) is the density of nanoparticles; \( c_{np} \) is the concentration of nanoparticles.

The permeability of formation can be improved by nanoparticle plugging removal, which is described by the Carmen–Kozeny law (Zhang et al. 2017):

\[
\left( \frac{K}{K_0} \right) = \left( \frac{\phi}{\phi_0} \right)^n \left( \frac{1 - \phi_0}{1 - \phi} \right)^2
\]

(2)

where \( K \) is the permeability after biological nano-technology; \( K_0 \) is original permeability.

After forming a hydrophobic film composed of nanoparticles, the slip effect will occur on nanoparticle film of porous walls (Fig. 1(b)), which will reduce the water flow resistance and improve the water-injection capacity (Gu et al. 2007, 2020; Liu et al. 2018). The adsorption of nanoparticles is described by the Langmuir isotherm (Alafnan et al. 2021):

\[
\hat{c}_{np} = \frac{A\phi_{np}}{1 + Bc_{np}}
\]

(3)

where \( \hat{c}_{np} \) is the concentration of nanoparticles adsorbed in the rock pores; \( A \) and \( B \) are the Langmuir adsorption constant.

![Fig. 1](image-url)  
**Mechanism of depressurization and injection-augmenting of biological nanoparticles.** a Nanoparticles are adsorbed on the pore wall and b the schematic diagram of slip effect (Li et al. 2021b)
After nanoparticle adsorption, the original water-wet pore throat surface is gradually changed to neutral or even oil-wet, and the relative permeability of the water phase is increased, which can be characterized by the change of seepage-resistance coefficient, relative permeability be calculated by

\[
K_{\text{rwnew}} = K_{\text{rw}} F_{\text{ai}}(\hat{c}_{\text{np}})
\]  

(4)

where \(K_{\text{rwnew}}\) is the relative permeability of formation water phase after biological nano-technology; \(K_{\text{rw}}\) is the relative permeability of formation water phase before biological nano-technology.

**Multiphase and multicomponent mathematical model**

The biological nano-materials coupling model of the water-drive reservoir is mainly composed of three parts: the waterflood reservoir-seepage model, nanoparticle-migration model, and reservoir porosity and permeability change model. The seepage equation of oil, water, and gas components in water-drive reservoirs is the same as that of the black-oil model (Todd and Longstaff 1972; Shoaib and Hoffman 2009; Nojabaei and Johns 2016; Du and Nojabaei 2020), and its basic assumptions are as follows:

1. The seepage flow in the reservoir is isothermal.
2. There are three phases of oil, gas, and water in the reservoir, and the seepage flow of each phase fluid conforms to Darcy’s law.
3. The model considers three components: the oil component, gas component, and water component.
4. The mass exchange of gas components occurs in the oil gas phase and the water gas phase.
5. The phase balance is completed instantly.
6. The water component only exists in the water phase, and there is no mass exchange with the oil gas phase.
7. The reservoir rocks are compressible and anisotropic.
8. The reservoir fluid is compressible, and the influence of gravity and capillary force in the seepage process should be considered.

Nanoparticles are regarded as a component dissolved in the water phase. According to the principle of conservation of matter, the continuity equation can be written as:

\[
\nabla \cdot \left( c_{\text{np}} K_{\text{wc}} \frac{\rho_B}{\mu_B} \nabla \left( \frac{\partial P}{\partial x} - \gamma_w \frac{\partial D}{\partial x} \right) \right) + \nabla \cdot \left[ d_{\text{np}} \phi S_w \nabla c_{\text{np}} \right] + q_w c_{\text{np}}
\]

\[
= \frac{\partial (\phi S_w c_{\text{np}})}{\partial t} + \frac{\partial}{\partial t} \left[ F_{\text{np}} \rho_k (1 - \phi) \hat{c}_{\text{np}} \right] + \frac{\partial c_{\text{np}}}{\partial t}
\]

(5)

where \(c_{\text{np}}\) is the concentration of nanoparticles; \(P\) is the formation pressure, \(x\) is the distance from the bottom of the injection well; \(S_w\) is the water saturation; \(q_w\) is the water-injection volume; \(d_{\text{np}}\) is the diffusion coefficient of nanoparticles; \(F_{\text{np}}\) is the percentage of pore surface in contact with the water phase.

The main components of the coupling model of depressurization and injection increase in biological nanoparticles in a water drive are given below. There are also some auxiliary equations, such as the relationship between saturation and the capillary force, the PVT physical-property equation, and the nanoparticle physicochemical equation:

\[
s_o + s_w + s_g = 1
\]

\[
p_{\text{cow}} = p_o - p_w
\]

\[
p_{\text{cog}} = p_g - p_o
\]

where \(S_o\) is the oil saturation; \(S_g\) is the gas saturation; \(p_o\) is the capillary pressure of oil; \(p_w\) is the capillary pressure of water; \(p_g\) is the capillary pressure of gas; \(p_{\text{cow}}\) is the between the \(p_o\) and \(p_w\); \(p_{\text{cog}}\) is the between the \(p_g\) and \(p_o\).

This system has the initial conditions given by

\[
P(x, y, z, 0) = p^0(x, y, z)
\]

\[
s_o(x, y, z, 0) = s^0_o(x, y, z)
\]

\[
s_g(x, y, z, 0) = s^0_g(x, y, z)
\]

(7)

For this conceptual model, it is an oil reservoir with a closed boundary.

\[
\frac{\partial P}{\partial n} \bigg|_L = 0.
\]

(8)

Finally, due to the existence of the well, there are the following conditions

\[
Q_i(x, y, z, t) = Q_i(t) \delta(x, y, z)
\]

(9)

\[
p_{\text{wfi}}(x, y, z, t) = p_{\text{wfi}}(t) \delta(x, y, z)
\]

(10)

where \(Q_i\) is the well yield; \(p_{\text{wfi}}\) is the well bottom-hole pressure; \(\delta(x, y, z)\) is the Dirichlet-like function, if \((x, y, z)\) corresponds to well coordinates, \(\delta(x, y, z) = 1\), otherwise \(\delta(x, y, z) = 0\).

In other words, it is not considered whether there is water supply in other places of the reservoir except the well.

**Model and method**

Taking the basic data of well group Q1 in the Bohai oilfield as an example, a water-drive conceptual model was established, as shown in Fig. 2. The main parameters were as follows: (1) The reservoir thickness was 30 m, porosity...
was 20%, and permeability was 30 mD. (2) The injection–production well spacing was 350 m, and the wells were arranged in reverse seven points. (3) The liquid production of a single well was controlled, the production well was 20 m³/d, and the water-injection well was 120 m³/d. (4) The properties of crude oil were that of conventional thin oil, and the formation pressure was 28 MPa. (5) The formation depth was 2600 m, and the temperature was 55 °C. (6) The compressibility and relative permeability of the rock fluids were as shown in Fig. 3. Lastly, the number of model grids was 100×100×10.

Water flooding model

Figure 4 shows simulation results of the water flooding with and without plugging. Without considering the formation damage caused by impurities in injected water, we can know from the without plugging curve in Fig. 4 that the oil production of the production wells was relatively stable, and the oil production began to decline gradually after the water breakthrough in 2022. The injection volume of the water-injection well remained constant, and the well head injection pressure and bottom-hole flow pressure remained basically constant, with only a slight decrease, which shows that the injection and production were basically maintained in a balanced injection–production state without considering the damage of the water-injection formation.

Based on the normal water flooding model without plugging, the blockage of the water-injection well near the well was simulated by adding an inorganic scale-formation reaction in the water phase. The well head pressure and well-bottom flow pressure could be obtained through numerical simulation. We can know from the plugging curve in Fig. 4 that the formation of the inorganic scale led to a decrease in porosity near the well, the injection volume gradually decreased when the injection well reached the maximum injection pressure, and the under-injection situation became increasingly serious.

Biological nanoparticle model

There are two main mechanisms for the on-site water injection of bio-nanoparticles to reduce pressure and increase injection: (1) dissolving inorganic scale and drive water film; (2) nano-materials adsorbing to form nano-film to reduce seepage resistance.

We assume that the number of nanoparticles in the two mechanisms is equal, and the injected nanoparticles react to generate nanoparticle components corresponding to the following two mechanisms:

\[
nanoFH \rightarrow 0.5nanoSH + 0.5nanoXF
\]

The first mechanism of action of some nanoparticles is to dissolve the inorganic scale; the chemical reaction is

![Fig. 2 3D schematic diagram of the CMG conceptual model](image)

![Fig. 3 Oil–water relative permeability curve of the CMG conceptual model](image)
We can know that the inorganic scale CaCO$_3$ dissolves and then transforms into S-nano component in liquid, resulting in an increase in porosity. Adding the Carmen–Kozeny formula option in the variable-permeability option could simulate the improvement of the water-phase permeability.

\[ \text{nanoSH} + \text{CaCO}_3(s) \rightarrow \text{Ca}^{2+} + \text{CO}_3^{2-} + S - \text{nano(l)} \]

The second mechanism of action of some nanoparticles is described by the Langmuir isotherm adsorption option on the pore wall, as shown in Fig. 1a.

On the basis of the water-drive simulation, the above two mechanisms were added, and the mole fraction of the nano-composite system was 0.0002 after one year of under-injection. When the injection time was two months, the injection rate remained unchanged. According to the simulation results, as shown in Fig. 5a, we can know that injecting the bio-nano-solution greatly delayed the under-injection time of the water-injection well, and reduced the well head pressure and bottom-hole flow pressure. The biological nano-solution was able to prolong the effective injection-allocation time of scaling and plugging wells.

The minimum well-bottom flow pressure of the production well was set at 21.5 MPa. According to the simulation results, as shown in Fig. 5b, compared with the change in the whole oil production, we can know that the oil production declined later after the injection of the biological nano-solution, and the decline rate was significantly lower than that of the water drive without measures.

**Sensitivity analysis of injection parameters of biological nano-technology**

There are two aspects to evaluate the construction effect of biological nano-technology. It is the decreasing amplitude of well head pressure of injection well, which is the difference...
between well head pressure before and after construction. The other is the increasing oil quantity of a well group, which is the difference between the cumulative oil production with and without biological nano-technology.

The depressurization effect of the biological nano-technology was evaluated by the maximum decline of the well head pressure after injection, and the final recovery was characterized by depressurization and injection increase as well as the cumulative oil increase.

**Influence of operation time**

To analyze the sensitivity of injection timing, the degree of under-injection in the formation is defined by referring to the water absorption efficiency of the formation (Zhao et al. 2017). Define the formation under-injection proportions are

\[
\alpha = 1 - \frac{Q_i}{Q_f}
\]

where \( \alpha \) is the under-injection rate of the formation; \( Q_i \) is the actual water-injection volume of the water-injection well; and \( Q_f \) is the theoretical water absorption of the formation, which is 120 m³/d here.

Figure 6 shows the influence of operation time on decreasing amplitude of well head pressure and increasing oil quantity of well group. We can know from Fig. 6 that the effect of biological nano-technology first increases and then decreases with the increase in the under-injection rate of formation. This can be explained as follows: the higher the degree of under-injection, the more organic scale and thicker water film in the formation. After the operation of biological nano-technology, the porosity and permeability will be improved significantly. However, when the degree of under-injection is too high, many channels have been completely blocked, and biological nanoparticles can’t enter the channels, so the effect is weakened.

**Influence of injection volume**

There are many ways to measure injection volume, such as injection volume and pore volume multiple (PV). For the sake of universality, we use pore volume multiple to measure injection volume here.

Figure 7 shows the influence of injection volume on decreasing amplitude of well head pressure and increasing oil quantity of well group. We can know from Fig. 7 that the decreasing amplitude of well head pressure and the increasing oil quantity have been increasing with the increase in injection volume. This can be explained as follows: the more biological nanoparticles are injected, the more strata will be affected, so the better the application effect of biological nano-technology.

**Influence of injection intensity**

Different injection rates will also change the behavior of nanoparticles after injection. If the injection rate is too fast, it will lead to formation blockage (Davin et al. 2022). As shown in Fig. 8.

For reservoirs with different thicknesses, the injection rate leading to formation plug will be different, so it can be measured by the injection rate per unit thickness. It can be expressed as

\[
\beta = \frac{Q_i}{h}
\]

where \( \beta \) is the injection intensity, m³/d/m.

**Fig. 6** Effect of operation time on decreasing amplitude of well head pressure and increasing oil quantity

**Fig. 7** Effect of injection volume on decreasing amplitude of well head pressure and increasing oil quantity
Figure 9 shows the influence of injection intensity on decreasing amplitude of well head pressure and increasing oil quantity of well group. From Fig. 9, we can know that with the increase in injection intensity, the decreasing amplitude of well head pressure is smaller and smaller, while the increasing oil quantity first increased and then decreased. This can be explained as follows: when the injection intensity is too high, the biological nanoparticles can't be uniformly transported to the formation area, which will lead to the decrease in permeability near the well for some time after the injection of biological nanoparticles. Therefore, increasing the injection intensity will reduce the well head pressure drop. With the passage of time, biological nanoparticles are gradually and evenly distributed in the reservoir, so the oil increase will increase. However, if the injection strength is too large, the migration process will take a long time, so the oil increase will decrease with the increase in injection intensity.

**Influence of concentration**

Figure 10 shows the influence of injection intensity on decreasing amplitude of well head pressure and increasing oil quantity of well group. From Fig. 10, we can know that with the increase in concentration, the oiling effect is getting better and better, but there is a maximum value, while the effect of well head pressure drop is significant but first increases and then decreases. This can be explained as follows: with the increase in concentration, the area of action will be enlarged correspondingly, but after reaching a certain level, too high concentration of nanoparticles may lead to the decrease in permeability near the well. On the other hand, when the concentration of nanoparticles is too high, the poor improvement effect will also reduce the decreasing amplitude of well head pressure.
Application and Discussion

Design plate of injection parameters of the biological nano-technology

Using the previous sensitivity analysis as the sample point, the injection parameters of injection volume, injection intensity, and injection concentration were represented by $x_1$, $x_2$, and $x_3$, respectively. Then, multivariate binomial fittings were carried out for the depressurization and injection-increase amplitude $y_1$ and cumulative oil increase $y_2$.

Through binomial fitting, the response equation of the depressurization amplitude within the range of the simulation parameters at 30 mD was obtained as follows:

$$y_1 = -2.422x_1^2 - 1.116x_2^2 - 1.134 \times 10^{-6}x_3^2$$
$$- 13.836x_1x_2 + 33.162x_1x_3 + 4.655$$
$$\times 10^{-3}x_2x_3 - 4.295x_1 + 4.577x_2$$
$$- 2.817 \times 10^{-2}x_3 + 8.203$$

The response equation of the cumulative oil increase in the range of the simulation parameters is as follows:

$$y_2 = -12.304x_1^2 + 0.675x_2^2 + 1.302 \times 10^{-8}x_3^2$$
$$+ 0.405x_1x_2 + 11.441x_1x_3 + 2.397$$
$$\times 10^{-3}x_2x_3 + 3.135x_1 + 4.214x_2$$
$$+ 0.0159x_3 + 2.215$$

According to the intersection of the predicted results and the actual results, as shown in Fig. 11, the binomial-fitting correlation coefficient exceeded 90%, indicating that the fitting formula had high fitting accuracy. As such, it can be used for reference in the prediction of design parameters for similar well-group biological nano-solution depressurization and injection-increase schemes.

Figure 12 shows the response surfaces of the decreasing amplitude and increasing oil quantity obtained by Eqs. 10 and 11. When we get the injection rate, PV, and injection concentration, then find the corresponding coordinates on the template in Fig. 12, and read out the color values of the corresponding coordinates, so as to predict the value of pressure drop and oil increase after using biotechnology according to the color chart in Fig. 12.

Field application

To verify the accuracy of the method in Sect. 5.1, the actual well-group data is used for verification (Table 1). The pressure drop is verified by the actual production data (Fig. 13a), while the oil increase is verified by the data obtained by numerical simulation software (Fig. 13b). The numerical simulation software used in this study is CMG (Computer Modelling Group ltd., Canada).

Well R22 is a water-injection well in oilfield, which began to be injected in November 2015, with an initial injection allocation of 450 m$^3$/d. In the process of injection, the well head pressure rose rapidly to about 12 MPa in a short time, and the actual water-injection rate gradually decreased from 400 m$^3$/d to about 50 m$^3$/d. With the water absorption capacity of the reservoir getting worse and worse in the injection process, the injection pressure rose to 15 MPa in the first half of 2018, and the daily injection rate rose to about 190 m$^3$/d. After acidizing measures were taken in May 2018, the daily injection rate rose to 250 m$^3$/d, but the water-injection rate dropped rapidly. The phenomenon of high injection pressure and under-injection is becoming more and more serious.
Before the biological nano-technology, the water-injection pressure is as high as 15 MPa or so, so that the injection allocation of 250 m³/d can be completed.

Biological nano-technology was used in Well R22 from July 1, 2019, to September 1, 2019. After the measures were implemented, the well head pressure dropped to about 6 MPa, which was about 6.5 MPa lower than that before the measures (Fig. 13a). The corresponding daily injection rate increased from 30 m³/d to 125 m³/d, which was 95 m³/d higher than that before the measures. The injection effect of water-injection wells was remarkable. Since the implementation of the measures to the current date, the injection rate has remained relatively stable, and the injection-increase effect is still good, which can meet the injection-allocation requirements of water-injection wells.

**Fig. 12** Design plate of injection parameters of the biological nano-solution: **a** template of decreasing amplitude and **b** template of increasing oil quantity

**Fig. 13** Results of biological nano-technology application: **a** reality well head pressure before and after application of biological nano-technology and **b** predicted cumulative oil with and without biological nano-technology by simulation

**Table 1** Basic parameters of the reservoir

| Parameter                                           | Value |
|-----------------------------------------------------|-------|
| Reservoir thickness (m)                             | 17.1  |
| Average porosity (%)                                | 20.036|
| Average permeability (mD)                           | 85.89 |
| Surface area of R22 group (10⁷m²)                   | 10.97 |
| Well head pressure before biological particle (MPa) | 15    |
| Injection strength of biological particle (m³/d/m)  | 5.595 |
| Injection concentration of biological particle (ppm)| 1200  |
| Injection volume of biological particle (PV)        | 0.000298 |
Figure 13a shows the actual well head pressure before and after application of biological nano-technology, we can know that the well head pressure is reduced by 6.5 MPa after using biological nano-technology, which is not much different from the calculated result in Table 2 by using the method described in Sect. 5.1. Figure 13b shows the comparison of the results of predicted cumulative oil by CMG (numerical simulation software). We can know by Fig. 13(b) that the cumulative oil production increased by 48,280 m³ after the application of biological nano-technology, while the result in Table 2 obtained by the method in Sect. 5.1 was 43,947 m³, which was close to each other, indicating that the method obtained in Sect. 5.1 was reliable.

Summary and Discussion

At present, the research on the application of nanoparticles in oil fields is still mostly in the laboratory theoretical stage. This study is the first time to analyze the sensitivity of biological nano-technology that has been applied in the mine, and get the influence of each construction parameter on the two most concerned parameters in the practical application process, namely, the amplitude of pressure reduction and the amount of oil increase. This study can provide a certain reference for theoretical research and field development scheme of similar nano-technology.

Although some preliminary original numerical simulation study has been done for biological nano-technology in the low- and medium-permeability reservoirs, there are still some defects that need further research in the future. Hence, some discussion and remarks are listed as following.

(1) The model adopts the conventional Carmen–Kozeny law to describe the porosity and permeability increasing after injecting biological nano-solution. Although we have incorporated some mechanisms of inorganic scale plugging removal and water film decreasing, the influence of some mechanism needs further evaluation by conducting experiments and simulation studies.

(2) The nanoparticle adsorption is described by using Langmuir isotherm equation, and the relevant water relative permeability decrease is simply characterized by the change of seepage-resistance coefficient. However, the adsorption amount and the resistance coefficient are difficult to obtain, which should be further investigated by doing more experiments.

(3) The new model can reasonably predict the depressurization and injection-augmenting performance of biological nano-solution. More model validation with coreflood experiments and well pattern cases need to be performed for improvements, especially for the parameters adjustment for actual field prediction application. Once the model is validated, the coupled model can be modified to simulate hybrid EOR process related to nanoparticle effect, such as nanoparticle-assisted polymer flooding process in the reservoirs of an offshore oilfield.

(4) In this study, in order to simplify the migration of nanoparticles in the reservoir, it is assumed that the diffusion of nanoparticles is along the radial direction. However, in the actual production process, many directional wells and horizontal wells will be used in offshore oil fields, which will lead to a small number of vertical diffusion of nanoparticles. Therefore, the simulation of directional wells and horizontal wells still needs to consider the influence of well types on the diffusion of nanoparticles in the actual use process.

Conclusions

This paper systematically studied the influence of injection parameters, such as operation time, injection volume, injection intensity, and concentration, on foam well head pressure and cumulative oil after the application of biological nano-technology. In addition, according to the binomial-fitting method, the chart for calculating the amplitude of depressurization and oil increase is obtained, and it is compared and verified by using the oilfield production data. Based on the results of this study, the following conclusions can be drawn.

(1) The production performance of Well R22 shows that biological nano-technology can effectively reduce the well head pressure of injection wells and increase the cumulative oil production of well groups.

(2) For different injection parameters, the sensitivity of biological nano-technology is different. The operation time, injection intensity, and concentration are more effective than injection volume in terms of decreasing amplitude and cumulative oil.

(3) The nearly perfect predicted decreasing amplitude and increasing oil quantity could be achieved by the design plate of injection parameters of the biological nano-technology.
However, there are some disadvantages of the method as follows:

In this study, the adsorption of nanoparticles was described by Langmuir equation, but a lot of experiments were not carried out to obtain the adsorption capacity and adsorption coefficient. At the same time, the adsorption process in this study is calculated based on vertical wells, so the simulation accuracy of non-vertical wells, especially horizontal wells, needs to be further verified and improved.

In this study, Carmen–Kozeny law is mainly used to simulate the change of nanoparticles on reservoir porosity and permeability, but the effect of nanoparticles on porosity and permeability still needs to be further evaluated and verified by experiments.

**Funding** This work was supported by the National Natural Science Foundation of China (Grant No. 51804048).

**Declarations**

**Conflict of Interest:** The authors declare that they have no conflict of interest.

**Ethical statements** I certify that this manuscript is original and has not been published and will not be submitted elsewhere for publication while being considered by Journal of Petroleum Exploration and Production Technology. And the study is not split up into several parts to increase the quantity of submissions and submitted to various journals or to one journal over time.

**Open Access** This article is licensed under a Creative Commons Attribution 4.0 International License, which permits use, sharing, adaptation, distribution and reproduction in any medium or format, as long as you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons licence, and indicate if changes were made. The images or other third party material in this article are included in the article’s Creative Commons licence, unless indicated otherwise in a credit line to the material. If material is not included in the article’s Creative Commons licence and your intended use is not permitted by statutory regulation or exceeds the permitted use, you will need to obtain permission directly from the copyright holder. To view a copy of this licence, visit http://creativecommons.org/licenses/by/4.0/.

**References**

Abdelfatah E, Pournak M, Shiau BI, ben, Harwell J, (2017) Mathematical modeling and simulation of nanoparticles transport in heterogeneous porous media. J Nat Gas Sci Eng 40:1–16. https://doi.org/10.1016/J.JNGSE.2016.09.060

Adil M, Zaid HM, Chuan LK, Latiff NRA (2016) Effect of Dispersion Stability on Electrochemistry of Water-Based ZnO Nanofluids. Energy Fuels 30(7):6169–6177. https://doi.org/10.1021/acs.energyfuels.6b01116

Agista MN (2017) A Literature review and transport modelling of nanoparticles for enhanced oil recovery. University of Stavanger.

Alafnan S, Awotunde A, Glatz G et al (2021) Langmuir adsorption isotherm in unconventional resources: Applicability and limitations. J Petrol Sci Eng 207:109172. https://doi.org/10.1016/J.PETROL.2021.109172

Alaskar M, Ames M, Connor S et al (2012) Nanoparticle and Micro-particle Flow in Porous and Fractured Media— An Experimental Study. SPE J 17:1160–1171. https://doi.org/10.2118/146752-PA

Alaskar M (2013) In-situ multifunctional nanosensors for fractured reservoir characterization. Stanford University.

Anderson RL, Ratcliffe I, Greenwell HC et al (2010) Clay swelling — A challenge in the oilfield. Earth Sci Rev 98:201–216. https://doi.org/10.1016/J.FARSIC.2009.11.003

Anees A, Zhang H, Ashraf U et al (2022) Sedimentary facies controls for reservoir quality prediction of lower shihezi member-1 of the hangjinqi area, ordos basin. Minerals 12(2):126. https://doi.org/10.3390/min12020126

Anees A, Zhang H, Ashraf U et al (2022b) Identification of favorable zones of gas accumulation via fault distribution and sedimentary facies: insights from hangjinqi area, northern ordos basin. Front Earth Sci 9:1375. https://doi.org/10.3389/FEART.2021.822670

Ansah EO, Vo Thanh H, Sugai Y et al (2020) Microbe-induced fluid viscosity variation: field-scale simulation, sensitivity and geological uncertainty. J Petroleum Explor Product Technol 10:1983–2003. https://doi.org/10.1007/S13202-020-00852-1/FIGURES/21

Ashraf U, Zhang H, Anees A et al (2021) A Core Logging, Machine Learning and Geostatistical Modeling Interactive Approach for Subsurface Imaging of Lenticular Geobodies in a Clastic Depositional System, SE Pakistan. Nat Resour Res 30:2807–2830. https://doi.org/10.1007/S11053-021-09849-X/FIGURES/13

Cao GS, Wang L, Wang GL (2014) Development of Polymer Gel Plugging Removal Agent in Suizhong 361 Oilfield. Adv Mater Res 860:1026–1029. https://doi.org/10.4028/www.scientific.net/AMR.860-863.1026

Chen H, Di Q, Ye F et al (2016a) Numerical simulation of drag reduction effects by hydrophobic nanoparticles adsorption method in water flooding processes. J Nat Gas Sci Eng 35:1261–1269. https://doi.org/10.1016/J.JNGSE.2016.09.060

Chen H, Xiao L, Xu Y et al (2016b) A novel nanodrag reducer for low permeability reservoir water flooding: Long-Chain alkylamines modified graphite oxide. J Nanomater. https://doi.org/10.1155/2016/8716257

Dai C, Li H, Zhao M et al (2018) Emulsion behavior control and stability study through decorating silica nanoparticles with dimethyldodecylamine oxide at n-heptane/water interface. Chem Eng Sci 179:73–82. https://doi.org/10.1016/J.CES.2018.01.005

Davin K, Najeebullah L, Tarek G et al (2022) A review on application of nanoparticles in cEOR: Performance, mechanisms, and influencing parameters. J Mol Liq 353:118821. https://doi.org/10.1016/J.MOLLIQ.2022.118821

Di QF, Hua S, Ding WP et al (2015) Application of support vector machine in drag reduction effect prediction of nano-particles adsorption method on oil reservoir’s micro-channels. Journal of Hydrodynamics, Ser B 27:99–104. https://doi.org/10.1016/S1001-6058(15)60461-9

Ding B, Xiong C, Geng X et al (2020) Characteristics and EOR mechanisms of nanofluids permeation flooding for tight oil. Pet Explor Dev 47:810–819. https://doi.org/10.1016/J.ISPEDET.2020.60096-9

Du F, Nojabaie B (2020) A black-oil approach to model produced gas injection in both conventional and tight oil-rich reservoirs to enhance oil recovery. Fuel 263:116680. https://doi.org/10.1016/J.FUEL.2019.116680

El-Amin MF, Salama A, Sun S (2015) Numerical and dimensional analysis of nanoparticles transport with two-phase flow in porous media. J Petrol Sci Eng 128:53–64. https://doi.org/10.1016/J.PETROL.2015.02.025
Fadili A, Murtaza A, Zitha P (2022) Injectivity decline by nanoparticles transport in high permeable rock. J Petrol Sci Eng 211:110121. https://doi.org/10.1016/J.PETROL.2022.110121

Feng X, Hou J, Cheng T, Zhai H (2019) Preparation and Oil Displacement Properties of Oleic Acid-modified Nano-TiO2. Oilfield Chemistry 36:280–285

Foroozesh J, Kumar S (2020) Nanoparticles behaviors in porous media: Application to enhanced oil recovery. J Mol Liq 316:113876. https://doi.org/10.1016/j.molliq.2020.113876

Franco-Aguirre M, Zabala RD, Lopera SH et al (2018) Interaction of anionic surfactant-nanoparticles for gas - Wettability alteration of sandstone in tight gas-condensate reservoirs. Journal of Natural Gas Science and Engineering 51:53–64. https://doi.org/10.1016/J.JNGSE.2017.12.027

Gu C, yuan, Di Q feng, Fang H ping, (2007) Slip velocity model of porous walls absorbed by hydrophobic nanoparticles SiO2. Journal of Hydrodynamics, Ser B 19:365–371. https://doi.org/10.1016/S1000-6058(07)60071-7

Gu C, Qiu R, Liu S et al (2020) Shear thickening effects of drag-reducing nanofluids for low permeability reservoir. Advances in Geo-Energy Research 4:317–325. https://doi.org/10.46600/age.2020.03.09

Irfan SA, Shaﬁe A, Yahya N (2019) Zainuddin N (2019) Mathematical Modeling and Simulation of Nanoparticle-Assisted Enhanced Oil Recovery—A Review. Energies 12:1575. https://doi.org/10.3390/EN12081575

Ju B, Dai S, Luan Z, et al (2002) A Study of Wettability and Permeability Change Caused by Adsorption of Nanometer Structured Polysilicon on the Surface of Porous Media. In: SPE Asia Paciﬁc Oil and Gas Conference and Exhibition. SPE Asia Paciﬁc oil and gas conference and exhibition.

Ju B, Fan T (2009) Experimental study and mathematical model of nanoparticle transport in porous media. Powder Technol 192:195–202. https://doi.org/10.1016/J.POWTEC.2008.12.017

Kalaim S, Afagw C, al Jaberi J, et al (2021) A review on non-aqueous fracturing techniques in unconventional reservoirs. J Nat Gas Sci Eng 95:104223. https://doi.org/10.1016/J.JNGSE.2021.104223

Kazemzadeh Y, Shojaei S, Riazi M, Sharifí M (2019) Review on application of nanoparticles for EOR purposes: A critical review of the opportunities and challenges. Chin J Chem Eng 27:237–246. https://doi.org/10.1016/J.CJCHE.2018.05.023

Lashari N, Ganat T (2020) Emerging applications of nanomaterials in chemical enhanced oil recovery: Progress and perspective. Chin J Chem Eng 28:1995–2009. https://doi.org/10.1016/J.CJCHE.2020.05.019

Lei Q, Luo J, Peng B et al (2019) Mechanism of expanding swept volume by nano-sized oil-displacement agent. Pet Explor Dev 46:991–997. https://doi.org/10.1016/S1876-3804(19)60255-7

Li J, Chen X, Gao P, Zhou J (2021a) Tight carbonate gas well deliverability evaluation and reasonable production proration analysis. Journal of Petroleum Exploration and Production Technology 11:2999–3009. https://doi.org/10.1007/s13202-021-01222-1

Li X, Feng Q, Gao P et al (2021b) Application progress of nano-sio2 in enhanced oil recovery and depressurization and injection-augmenting. Sci Technol Eng 21:8291–8300

Li D (2014) Analysis of sedimentary facies and favorable area prediction of the member 2 of yanchang formation in zhijiang oilfield. Xi’an Shiyou University.

Li Y (2021) System development and performance evaluation of the depressurizing and injection enhancing complex surfactant in the extra-low-permeability oil reservoirs of Ordos Basin. Petroleum Geology Oilfield Development in Daqing. https://doi.org/10.10597/j.issn.1000-3754.20210106

Liu P, Tao X, Li X et al (2017) Depressurizing and injection-augmenting behavior of water-based silica nanoparticle in low-permeability reservoir. Oilfield Chem 34:604–609

Liu P, Niu L, Tao X et al (2018) Preparation of superhydrophobic oleophilic quartz sand filter and its application in oil-water separation. Appl Surf Sci 447:656–663. https://doi.org/10.1016/J.APSUSC.2018.04.030

Liu Z, xia, Liang Y, Wang Q, et al (2020) Status and progress of worldwide EOR ﬁeld applications. J Petrol Sci Eng 193:107449. https://doi.org/10.1016/J.PETROL.2020.107449

Lu X, Lv G, Luan Z et al (2003) Application of poliesilicon in low permeability oil field. Pet Explor Dev 30:110–122

Ma T, Zhang K, Shen W et al (2021) Discontinuous and continuous Galerkin methods for compressible single-phase and two-phase flow in fractured porous media. Adv Water Resour 156:104039. https://doi.org/10.1016/J.ADVWATRES.2021.104039

Moghadasi R, Rostami A, Hemmati-Sarapardeh A, Motie M (2019) Application of nanosilica for inhibition of fines migration during low salinity water injection: experimental study, mechanistic understanding, and model development. Fuel 242:846–862. https://doi.org/10.1016/J.FUEL.2019.01.053

Motta ABG, Thompson RL, Favero JL et al (2021) Rheological effects on the acidizing process in carbonate reservoirs. J Petrol Sci Eng 207:109122. https://doi.org/10.1016/J.PETROL.2021.109122

Nojabaei B, Johns RT (2016) Extrapolation of black- and volatile-oil fluid properties with application to immiscible/miscible gas injection. J Nat Gas Sci Eng 33:367–377. https://doi.org/10.1016/J.JNGSE.2016.03.101

Omari A, Cao R, Zhu Z, Xu X (2021) A comprehensive review of recent advances on surfactant architectures and their applications for unconventional reservoirs. J Petrol Sci Eng 206:109025. https://doi.org/10.1016/J.PETROL.2021.109025

Qin Z (2016) The research on decompression and injection stimulation of nanometer emulsion in low permeability reservoir. Reservoir Eval Develop 6:61–66

Qu M, Hou J, Lianq T, Qi P (2021) Amphiphilic Rhamnolipid Molybdenum Disulﬁde Nanosheets for Oil Recovery. ACS Appl Nano Mater 4(3):2963–2972. https://doi.org/10.1021/acsanm.1c00102

Ren X, Wang R, Pan Q et al (2021) Effect of Nano-sized Oil-displacement Agent in Increasing Water Injection for Oil Displacement. Oilfield Chemistry 38:147–151

Salama A, Negara A, el Amin M, Sun S (2015) Numerical investigation of nanoparticles transport in anisotropic porous media. J Contam Hydrol 181:114–130. https://doi.org/10.1016/J.JCONHY.2015.06.010

Shen W, Ma T, Li X et al (2022) Fully coupled modeling of two-phase fluid flow and geomechanics in ultra-deep natural gas reservoirs. Phys Fluids 34:043101. https://doi.org/10.1063/5.0084975

Shoaiib, Hoffman BT (2009) CO2 flooding the elm coulee field. SPE Rocky Mountain petroleum technology conference.

Silei L (2018) Research Progress in application of nanomaterials in decompression and augmented injection of oilﬁelds. Liaoning Chem Industry 47:957–959

Thai Ba N, Vo Than H, Sugai Y et al (2020) Applying the hydrodynamic model to optimize the production for crystalline basement reservoir. X field, Cau Long Basin. Vietnam J Petroleum Explor Product Technol 10:31–46. https://doi.org/10.1016/J.JCONHY.2022.019-00755-W/ TABLES/5

Thanh HV, Sugai Y (2021) Integrated modelling framework for enhancement history matching in fluvial channel sandstone reservoirs. Upstream Oil and Gas Technol 6:100027. https://doi.org/10.1016/J.UPSTRE.2020.100027

Todd MR, Longstaff WJ (1972) The Development, Testing, and Application Of a Numerical Simulator for Predicting Miscible Flood Performance. J Petrol Technol. https://doi.org/10.2118/3484-PA
Wang Y, Zhao M, Dong X et al (2020) Potential of the base-activated persulfate for polymer-plugging removal in low temperature reservoirs. J Petrol Sci Eng 189:107000. https://doi.org/10.1016/J.PETROL.2020.107000

Wang X, Gong L, Guo Q et al (2021) Numerical simulation of the distribution of invading fines in packed proppant. J Petrol Sci Eng 206:108977. https://doi.org/10.1016/J.PETROL.2021.108977

Xu D, Ning J, Tang Y, et al (2019) Composite nano polysilicon pressure reduced augmented injection technology for water injection well. Drilling & Production Technol 42:50–52

Yadali Jamaloei B (2011) Chemical flooding in naturally fractured reservoirs: fundamental aspects and field-scale practices. Oil & Gas Sci Technol Revue d’IFP Energies nouvelles 66:991–1004. https://doi.org/10.2516/OGST/2010040

Yang H (2017) Experimental Study on nano-emulsion system for injection improvement in tight reservoir. Xinjiang oil & gas(Edition of Natural Science) 13:76–81

Yi Z (2017) Optimization of Process Parameters for Nano Depressurization and Augmented Injection Technology in Extra-low Permeability Reservoir. Chongqing University of Science and Technology.

Yuan S, Wang Q (2018) New progress and prospect of oilfields development technologies in China. Pet Explor Dev 45:698–711. https://doi.org/10.1016/S1876-3804(18)30073-9

Zawrah MF, Khattab RM, Girgis LG et al (2016) Stability and electrical conductivity of water-base Al₂O₃ nanofluids for different applications. HBRC Journal 12(3):227–234. https://doi.org/10.1016/j.hbrcj.2014.12.001

Zhai H, Qi N, Sun X et al (2019) Preparation and evaluation of a new type step-down augmented injection agent made of SiO nanoparticle. Materials Reports 33:975–979

Zhang H, He S, Wu J, et al (2017) A New Method for Predicting Permeability Based on Modified Kozeny-Carmen Equation. Journal of Jilin University(Earth Science Edition) 47:899–906

Zhao M, Wang S, Dai C (2017) A new insight into the pressure-decreasing mechanism of hydrophobic silica nanoparticles modified by n-propyltrichlorosilane. J Surfactants Deterg 20:873–880. https://doi.org/10.1007/s11743-017-1966-4

Zhou L, Ma H, Fang K, Shen J (2004) Evaluation of injector damage in the Lunnan Oilfield, Tarim Basin. Pet Explor Dev 31:117–119

Publisher’s Note Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.