Research Article

Evaluation and Utilization of Nano-Micron Polymer Plug for Heterogeneous Carbonate Reservoir with Thief Zones

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Thief zones are highly permeable zones in oil reservoirs which affect the performance greatly during water flooding. The most effective way to prevent the invalid circle of thief layer is the injection of high-concentration polymer slugs. In this paper, the plugging effect of nano-micron polymer flooding on the thief zone is studied by experimental and theoretical analysis. The changes of water content and flow resistance were analyzed under different conditions. The result shows that the model presented here has good agreement with the experimental results. The displacement effect is the best when the thief zone is located on the upper part of the reservoir. And the water content will decrease with the increase of flow resistance after nano-micron polymer injection. Besides, the higher the polymer concentration, the more obvious the decrease of water content, and more effective the plugging. This study has provided a quick and reasonable guide in the later adjustment of water flooding development of carbonate reservoirs with thief layers.

1. Introduction

Carbonate reservoir refers to the accumulation of oil and gas in carbonate traps. And it is one of the most important hydrocarbon reservoirs in the world, which accounts for about half of the global reserves. The proportion of the output has reached more than 60% of the total output. Compared with the conventional sandstone reservoir, the development efficiency of the carbonate reservoir is lower. Carbonate reservoirs have typical characteristics of multiple media and serious permeability heterogeneity [1–4].

Because of the strong heterogeneity and complicated reservoir structure, invalid cycle channels easily appear in carbonate reservoirs. The permeability of the invalid cycle channels is very high, and most of the water flows through this area during water flooding, which greatly reduces the effective utilization area and displacement efficiency. And then, the formation pressure of the carbonate reservoir

declines rapidly under the exploitation method with natural energy, which will lead to low efficiency [5–8]. Most oil fields use water injection to supplement the pressure loss. But long-time water injection can also cause damage to the reservoir and water circulate inefficiently, which is unfavorable to enhance the overall recovery of the oil field.

The result of PLT logging in many oil fields shows that there is a thin layer with high permeability, and most of the production fluid comes from this layer. The contribution ratio of the layer is far beyond its thickness ratio, and we call them “thief zones”, which is one of the important manifestations of heterogeneity in carbonate reservoirs [9–11]. In the process of water injection, large amounts of water tend to flow through the thief zone, which results in water breakthrough quickly and low recovery. Therefore, how to identify and characterize these thief zones effectively has been increasingly attracting reservoir engineers' attention [12–15].

There are several techniques to research and characterize the thief zones. Generally speaking, there are core analysis, well logging, well testing, and reservoir engineering methods. Although these methods can calculate and characterize the specific parameters of thief zones, it is always time consuming and expensive compared with the theoretical method and numerical simulation, and they cannot determine the level of the thief zone [16–21].

To meet the needs of water injection in different stages of oil field development, the technology of stratified water flood has been started since the 80s of the last century, which could enhance oil recovery greatly [22]. For vertically heterogeneous reservoirs, the method of stratified water flood can avoid the formation of dominant channels, slow down the rate of water cut increase, and ultimately improve the recovery rate of oil reservoirs. In addition, for heterogeneous reservoirs, using water polymer alternative flooding can achieve the purpose of blocking large channels, improving the sweep area, and ultimate recovery [23, 24]. The nano-micron polymer dispersion system has the characteristics of water swelling, which makes it expand rapidly in the process of injection into the high water-cut layer, slows down the flow rate of fluid, and then plays a role in plugging [25, 26].

In this paper, firstly, a mathematical model considering the flow resistance is established to study the effect of polymer plug on the thief zone. Secondly, the plugging effect of polymer flooding on the thief zone is studied by experimental analysis. The result shows that the present model has good agreement with the experimental results. The water displacement effect is the best when the thief zone is located on the upper part of the reservoir. And the water content will decrease with the increase of flow resistance after the polymer injection. In addition, the higher the polymer concentration, the more obvious the decrease of water content, and the more effective of the plugging. This study has provided a quick and reasonable guide in the later adjustment of water flooding development of carbonate reservoirs with thief layers.

2. Mathematical Model

2.1. Flow Resistance Model of the Nano-Micron Polymer Expansion System. Flow resistance is the most important factor to affect the fluid flow, especially in the reservoirs with strong heterogeneity, which have a great influence on the water distribution of different layers. In addition, gravity also plays an important role in fluid flow in heterogeneous reservoirs. To avoid the formation of an invalid cycle channel, we inject the polymer with high concentration to increase the flow resistance and then increase the swept area. Because of gravity, the fluid has a flow potential in the direction of gravity, so when the horizontal direction is plugged, the flow potential of the area below is stronger, which results in a larger swept area. The location of the polymer plug also has a great influence on the swept area as shown in Figure 1.

In this paper, we studied the mathematical mechanism of polymer flooding to improve the displacement efficiency of reservoirs with the thief zone using the method of flow resistance.

The basic assumptions used in this study are as follows: (1) constant rate production; (2) closed boundary condition; (3) capillary pressure influences are negligible; (4) the reservoir temperature is constant; and (5) the permeability is isotropic.

The motion equation fully describing the multiphase flow characteristics is:

$$\vec{v}_j = -\frac{KK_{rj}}{\mu_j}(\nabla p + \rho_j g), \quad (1)$$

where $j = o, w, p$, $\vec{v}_j$ is the velocity of fluids, K is absolute permeability of the reservoir, K_{rj} is the relative permeability of oil-water-polymer (three-phase), μ_j is the viscosity of fluids, ∇p is the differential pressure, ρ_j is the density of fluids, and g is the acceleration of gravity.

According to the similarity theory of hydropower, we can obtain the water injection rate and the productivity of each layer [27].

$$Q_i = \frac{P}{R_i}. \quad (2)$$

Water injection layer:

$$R_i = \frac{1}{2\pi h_i k_i f_{i,1}} \ln \frac{r_{i,1}}{r_w} + \frac{1}{2\pi h_i k_i f_{i,1}} \ln \frac{r_e}{r_{i,1}}. \quad (3)$$

Thief zone:

$$R_{th} = \frac{1}{2\pi h_{th} k_{th} f_{th,1}} \ln \frac{r_{th,1}}{r_w} + \frac{1}{2\pi h_{th} k_{th} f_{th,2}} \ln \frac{r_{th,2}}{r_{th,1}} + \frac{1}{2\pi h_i k_i f_{th,3}} \ln \frac{r_e}{r_{th,2}}. \quad (4)$$

The total flow resistance:

$$R_t = \frac{1}{(1/R_{th}) + \sum_{i=1} 1/R_i}, \quad (5)$$

where $f_{i,n} = (k_{roi,n}/\mu_o) + (k_{rwi,n}/\mu_{w,n})$ is the slug fluidity, i is the number of the layer, R_i is resistance of layer i , h_i is the thickness of layer i , k_i is permeability of layer i , P_j is the pressure of oil-water (two phases) considering gravity, r_e is the well spacing, r_w is the radius of the wellbore. Q_i is liquid production of each layer, $\bar{P}$ is the average formation pressure, and Q_t is the total water injection rate.

And equation (1) shows that the flow velocity is a vector, and there is also a flow velocity in the vertical direction influenced by gravity. So we must consider the gravity when we calculate the flow resistance. And then the new flow resistance equation is obtained as follows:

Upward flow:

$$Q_{vi} = \frac{P - \rho_w g}{R_{vi}} = \frac{P - \rho_w g}{\alpha R_i}. \quad (6)$$

Downward flow:

$$Q_{vi} = \frac{P + \rho_w g}{R_{vi}} = \frac{P + \rho_w g}{\alpha R_i}. \quad (7)$$

So if there are n layers, the actual injection of each layer is

FIGURE 1: Diagram of the swept range of polymer flooding under different locations of the thief layer. (a) Upper. (b) Middle. (c) Bottom.

$$\begin{cases} Q_{t,i} = Q_{h,i} + Q_{v,i} = \frac{P}{R_{h,i}} + \frac{P - \rho_w g}{\alpha R_{h,i+1}}, & i = 1, \\ Q_{t,i} = Q_{h,i} + Q_{v,i} = \frac{P}{R_{h,i}} + \frac{P \pm \rho_w g}{\alpha R_{h,i+1}}, & n > i \geq 2, \\ Q_{t,i} = Q_{h,i} + Q_{v,i} = \frac{P}{R_{h,i}} + \frac{P + \rho_w g}{\alpha R_{h,i-1}}, & i = n. \end{cases} \quad (8)$$

If there are n layers, the total liquid production is $Q = \sum_{i=1}^n Q_{t,i}$, the single-layer water production is $Q_{w,i} = \bar{P} / (\mu_w / 2\pi k_{w,i} h_i) \ln(r_e / r_w)$, and the total water production is $Q_w = \sum_{i=1}^n Q_{w,i}$.

Then the water content can be expressed as follows:

$$f_w = \frac{Q_w}{Q} = \frac{\sum_{i=1}^n Q_{w,i}}{\sum_{i=1}^n Q_{t,i}}. \quad (9)$$

3. Experiments and Model Validation

3.1. Experimental Procedure. In this paper, we experimented with the thief zone in the middle of the model. Based on the plane unidirectional flow theoretical model, the applicability of the model is verified by experiments. The model consists of two parts: the matrix layer and thief zone, as shown in Figure 2. Matrix layer size is 4.5 cm*4.5 cm*60 cm, the thickness of the thief zone is 0.3 cm, and the specific parameters are shown in Table 1. The experimental equipment is shown in Figure 3.

The experimental oil is a mixture of crude oil and kerosene. The whole process is carried out at 80°C, the viscosity is 1.7 MPa·s, and the water salinity is 260 thousand. The specific process is as follows:

- (1) Firstly, the cores need to be evacuated for 6 hours and saturated with original formation water. Then permeability was tested using formation water at the reservoir temperature (80°C).

FIGURE 2: The experimental model of the thief zone.

TABLE 1: Core parameters of the water flooding test with the thief zone in the middle of MB.

Core	Size (cm)	Permeability (mD)	Thickness (cm)	Porosity (%)
Matrix layer		50	2.1	
Thief zone	4.5 × 4.5 × 60	1000	0.3	20.58
Matrix layer		50	2.1

FIGURE 3: Experimental apparatus.

- (2) Using the special heterogeneous saturated oil holder, saturated formation water in the core is displaced by crude oil to build irreducible water. The displacement speed is gradually increased until no water appears, maintaining for 24 h.
- (3) At a temperature of 80°C, water flooding experiment is carried out through layered water injector at 1 m/d, and the experiment will end when the water content reaches 95%.

FIGURE 4: Comparison of experimental data and the presented model.

FIGURE 5: The relationship between pressure and time under different polymer concentrations.

- (4) Repeating the step 3, the polymer is injected into the model when the water content reaches 90% and ended when the water content reaches 95%.
- (5) During the displacement process, the liquid produced from the holder is measured every 10 min, and the oil and water output was recorded. The data are appropriately encrypted in phase with the water content of the produced liquid exceeding 90%. The pressure data are automatically collected by using a computer.

3.2. Experimental Results and Model Verification. As seen in Figure 4, water began to be produced when the injection amount reached 0.17PV, and then the water content increased rapidly. After injecting the polymer, the water

content decreased gradually, and it began to grow slowly after reaching 84%.

Figure 4 displays the comparison of experimental data and the presented model. The result shows that the present model has good agreement with the experimental results. Figure 5 shows the relationship between pressure and time under different polymer concentrations. The result shows that the higher the polymer concentration, the longer the pressure maintenance.

4. Results and Discussion

Under the reservoir size, the effect of different factors on water content is analyzed using the present model. And the thief zone is in the middle of the reservoir. The necessary physical parameters are shown in Table 2 and 3.

TABLE 2: The reservoir physical parameters.

Stratum	Oil viscosity (MPa·s)	Water viscosity (MPa·s)	Well spacing (m)	Permeability (mD)	Thickness (m)	Porosity (%)
Thief zone	5	1	200	1000	2	20.58
Matrix layer				50	50	

TABLE 3: The relative permeability of the reservoir.

Sw	Krw	Kro
0.35	0	1
0.4107	0.041	0.725
0.438	0.063	0.605
0.462	0.082	0.514
0.486	0.101	0.434
0.51	0.124	0.362
0.534	0.15	0.297
0.56	0.178	0.222
0.582	0.2	0.175
0.606	0.227	0.121
0.63	0.257	0.082
0.654	0.285	0.047
0.6679	0.305	0.029
0.682	0.33	0.011
0.69	0.346	0

FIGURE 6: Curves of water content and flow resistance with time during polymer flooding.

4.1. Variation of Water Content and Flow Resistance. Figure 6 shows the variation of water content and flow resistance with time during polymer flooding. The results show that the flow resistance decreases a little bit before water breakthrough. But once it happens, the water content will increase rapidly and the flow resistance will show the opposite trend. After polymer injection, the flow resistance will be obviously raised and the water content will decrease at the same time, which is the main period of enhanced oil recovery.

4.2. Influence of Polymer Concentration on Reservoir Water Content. Figure 7 shows the relationship between the water content and injection volume under different polymer concentrations. From Figure 7, we can know that the water content decreases obviously with the increase of the polymer concentration, which has a better plugging effect. Taking into account the input-output ratio of the production, the optimal polymer concentration should be controlled within 2.5 g/L.

FIGURE 7: Water content with different polymer concentrations.

5. Conclusion

In this paper, the plugging effect of polymer flooding on the thief zone is studied by experimental and theoretical analysis. The changes of water content and flow resistance were analyzed under different conditions. The result shows that the present model has good agreement with the experimental results. The water displacement effect is the best when the thief zone is located on the upper part of the reservoir. And the water content will decrease with the increase of flow resistance after polymer injection. In addition, the higher the polymer concentration, the more obvious the decrease of water content, and the more effective the plugging. The optimal polymer concentration should be controlled within 2.5 g/L. This study has provided a quick and reasonable guide in the later adjustment of water flooding development of carbonate reservoirs with thief layers.

Data Availability

The data used to support the findings of this study are included within the article.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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