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أسلوب توزيع معدل حقن/إنتاج المطبقة لفيضانات البوليمر الفاعل

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الخلاصة

إن تكنولوجيا تعزيز استخراج النفط باستخدام عناصر النشطة للسطح في الصين قد تم تطبيقها في شركة حقول النفط شنغلى على نطاق واسع، مرحلة فيضان المياه المستمر اللاحق بعد إكمال حقن سبيكة الكيميائية، سوف تحصل قدرة الحقن مع المواد الكيميائية من البوليمر اللازقة على استعادة الانتعاش، وبالتالي فمن الممكن في هذه المرحلة لزيادة كمية السوائل من الحقن والإنتاج. ولكن نظرا لعدم تجانس خزان النفط، إذا لكل بئر في نفس زيادة استخراج كمية السوائل فمن الصعب لتحقيق أفضل تأثيرات التنمية.

يعرض هذا البحث أن البوليمر المحقونة كأنها مرسمة، وهي طرحت طريقة حسب الربط بين الآبار وفقا لمنحنى التركيز من البوليمر المنتوجة من آبار الإنتاج، مثل شركة حقول النقط شنغلى خزان النفط 7th، تم إنشاء واحد نوع من بوليمر-طريقة توزيع كمية السائل للحقن والإنتاج في مرحلة فيضان المياه المستمر اللاحق من فيضان عناصر النشطة للسطح. هذه الطريقة من جهة واحدة وفقا لأسلوب الاحتياطيات المتبقية ومحتوى الرطوبة بعد سيطرة مجموعة جيدا حقن مادة كيميائية على كمية حقن بئر واحدة لتحسين التوزيع، ومن جهة أخرى، وفقا لمجموعة بين الآبار وآبار الإنتاج حقن الرطوبة وآبار الإنتاج على واحد والاتصال كذلك لتحسين توزيع الإنتاج. وأخيرا، استخدام طريقة المحاكاة العددية للتحقق من صحة هذه الطريقة، فقد بينت النتائج أن الطريقة المقترحة مقارنة مع الطريقة التقليدية، ويمكن تحقيق أقل محتوى الرطوبة واستخراج النفط العالي، لذا هذه الطريقة يمكن أن تساعد على البوليمر – خزان النفط من فيضان عناصر النشطة للسطح في مرحلة مياه الفيضانات اللاحقة للحصول على أفضل تأثيرات التنمية.

An injection/production rate allocation method applied for polymer-surfactant flooding

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ABSTRACT

Polymer-surfactant flooding which is an effective technology to enhance oil recovery, has been widely applied in Shengli oil field of China. At the stage of subsequent water flooding after polymer-surfactant injection, the injectivity and productivity of wells recover gradually along with the production of chemical solution which provides the feasibility of increasing the injection and production rates. However, due to reservoir heterogeneity, a poor performance may be obtained if the injection and production rates are simply increased for all wells at a same percent.

This paper treats the injected polymer as a tracer and a method to calculate the interwell connectivity is proposed according to the concentration curve of the production well. Then taking Gudong 7th reservoir in Shengli oil field which is developed by polymer-surfactant flooding as example, an injection/production rate allocation method applied for subsequent water flooding period is proposed. On one hand, well injection rates are allocated according to the remaining geological reserves and watercuts of different well groups; on the other hand, well production rates are allocated according to the watercuts of the wells in each well group and the interwell connectivity between the injection well and production well. Finally, the performance of the method is analyzed according to a numerical simulation method. The results show that the method gains lower watercut and higher oil recovery compared to the conventional method, and it is helpful to get a bigger oil recovery at the subsequent water flooding stage.

Keywords: Injection/production rate allocation; interwell connectivity; polymer and surfactant flooding; subsequent water flooding.

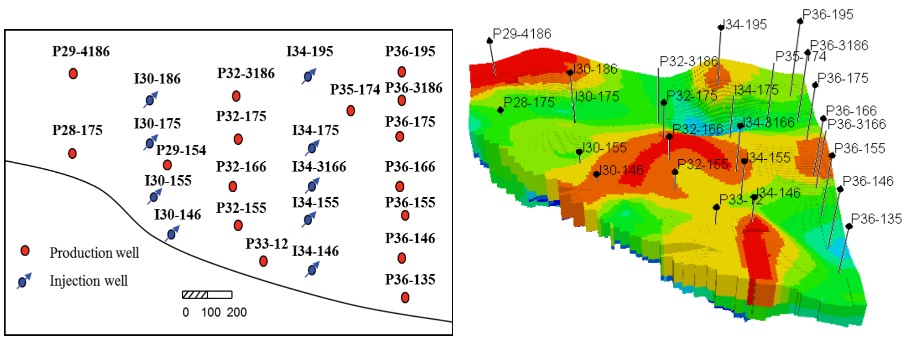
INTRODUCTION

Mature oilfields which contribute significantly to the total world oil production, generally suffer from a high water cut, which can significantly decrease oil production rates. How to keep the oil production rate stable and enhance oil recovery is an important concern of petroleum industry (Wang et al., 2015; Sedaghat et al., 2013; Song et al., 2014). Polymer-surfactant flooding which serves as an effective technology to enhance oil recovery has been widely applied in China for many years (Lan et al., 2009; Lu et al., 2014; You et al., 2013). On one hand, polymer could increase water viscosity and reduce the mobility ratio between oil and water phases so as to improve sweep efficiency (Alvarado & Manrique, 2010; Krishna & Kishore, 2013; Behruz & Arne, 2013; Shirman et al., 2014). On the other hand, surfactant behaves in another way by reducing the interfacial tension of the oil and water, increasing the capillary number, altering the wettability of rock, so as to reduce the residual oil saturation and drive more oil out (Chen & Zhao, 2015; Hirasaki et al., 2011; Gao et al., 2014). Since September 2013, Shengli oil field has implemented 17 polymer-surfactant flooding projects, which, cover 138.59 million tons of geological reserves and has increased 5.88 million tons of oil production (Gao et al., 2014; Chen et al., 2010; Wang et al., 2009).

At the polymer and surfactant injection stage, both the fluid injectivity and productivity decrease due to the high viscosity of the injected solution. However, after the injection of polymer-surfactant, i.e., at the stage of subsequent water flooding period, the injectivity and productivity of wells recover gradually along with the production of the injected chemical solution, which provides the feasibility of increasing the injection and production rates. Indeed, this is a conventional measure, which is widely applied in polymer and surfactant flooding oil fields in China to get an acceptable oil production rate at this stage (Chang et al., 2006; Hou et al., 2016). However, due to reservoir heterogeneity, a poor performance may be obtained if the injection and production rates are simply increased for all wells at a same percent (Ashok, 2009). Therefore, in order to yield a higher oil recovery, many scholars proposed several injection/production rate allocation methods, which mainly take static parameters including the formation thickness, geological reserve, pore volume, etc. into consideration (Bieker et al., 2007; Sarma et al., 2005; Liu, 2007; Hu et al., 2015). These methods are useful at the initial production stage, while they may be less effective in subsequent water flooding stage. This is because polymer-surfactant flooding is often applied after long-term water flooding period and the initial reservoir permeability, porosity and distribution of oil and water may have been greatly changed during this period. Therefore, the above methods, which only consider static parameters, may not be suitable anymore (Liang et al., 2007).

The interwell connectivity could dynamically represent the heterogeneity between wells, so it is helpful to predict the following water flooding performance and can be used to allocate the injection and production rates. The conventional measuring methods of the interwell connectivity include tracer test, interference well test, etc. (Onur et al., 2011; Lee et al., 2010). However, these methods are usually complicated or must disturb the normal production process. This paper takes Gudong 7th reservoir in Shengli oil field, which is developed by polymer-surfactant flooding as an example. An injection/production rate allocation method applied for subsequent water flooding period is proposed. The method firstly takes the polymer injected as a tracer and the interwell connectivity is calculated according to the curves of polymer concentration of the production well. Then the injection rates are optimized according to the remaining geological reserves and watercuts of the well groups, and the production rates are optimized according to the watercuts and interwell connectivity of the production wells. Finally, the performance of the method is analyzed and compared by using commercial software CMG, which is produced by CMG Corporation and is one of most popular software in chemical flooding simulation.

DESCRIPTION AND MODEL BUILDING OF THE RESERVOIR



(a) 2D distribution (b) 3D distribution

Fig. 1., Gudong 7th reservoir

Gudong 7th reservoir, which is a polymer-surfactant flooding pilot test block is located in Shengli oil field of China. It contains three layers and part of the reservoir properties are as follows: Oil bearing area is 0.94km^2, average thickness is 12.3m, geological reserve is 277×104t, average porosity is 0.34, average permeability is 1320×10-3μm2, initial oil saturation is 0.72, oil viscosity is 45mPa·s, salinity of the formation water is 3152mg/L, initial reservoir temperature is 68^{O}C and initial pressure is 12.4MPa.

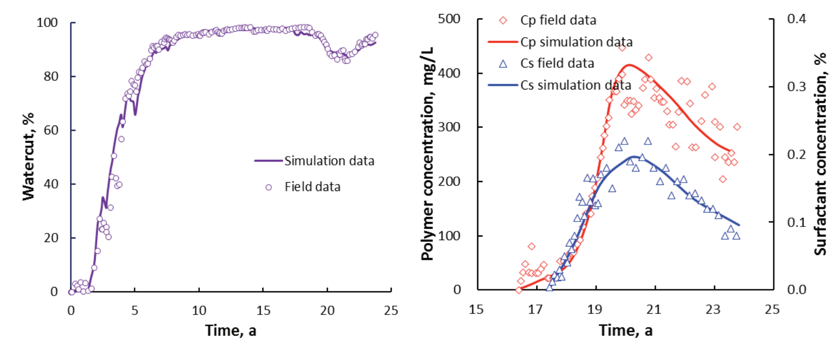
Figure 1 shows the 2D and 3D distribution of the reservoir. As shown in this figure, there are 25 wells including 16 production wells and 9 injection wells. The distance between the rows of injection well and production well is about 300m and the well spacing in each row is about 150m.

Table 1 shows detailed information of the injected polymer-surfactant slugs. As shown in this table, the pre-polymer slug, which only contains polymer, has been injected since September 2009. Then the main polymer-surfactant slug, which contains both polymer and surfactant has been injected since June 2004. The rear polymer slug, which also only contains polymer has been injected since April 2004 and the subsequent water flooding was the last to be implemented in January 2010.

Table1. Detailed information of the injected chemical slugs

Slug	Period	Mass of the chemical		Slug size PV
		Polymer t	Surfactant t	
Pre-polymer slug	2003.9-2004.5	774	0	0.078
Main polymer-surfactant slug (I)	2004.6-2007.5	2716	8201	0.302
Main polymer-surfactant slug (II)	2007.6-2009.4	1560	3360	0.188
Rear polymer slug	2009.4-2010.1	394.822	0	0.067
Subsequent water flooding	2010.1-present	0	0	——

Using commercial software CMG, the numerical simulation model of Gudong 7th reservoir is established and shown in Figure 1(b). There are 132 and 115 grids at x and y directions respectively and the length of each grid is 10m. In the vertical direction, the model contains three simulation layers and the thickness of each layer is 10m. Then based on the injection and production data, the history matching of watercut and chemical concentration of the produced fluid is done for the whole region and the results are shown in Figure 2. From this figure, we can see that the history matching result is good and the model is reliable to analyze the feasibility of increasing the injection and production rates and the performances of different allocation methods.

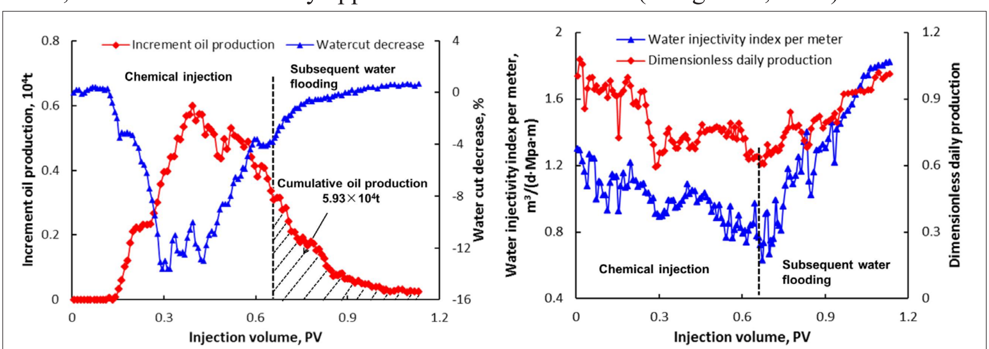


(a) Watercut (b) Chemical concentration of the produced fluid

Fig. 2. History matching of the production data

FEASIBILITY OF INCREASING THE INJECTION AND PRODUCTION RATES

Figure 3(a) shows the watercut and incremental oil production of Gudong 7th reservoir during polymer and surfactant flooding. The dotted line divides the curves into two parts. The left part represents the chemical injection period and the right part represents the subsequent water flooding period. From this figure, we can see that on one hand, subsequent water flooding period is an important part in which the cumulative incremental oil production has reached up to 5.93×104t taking up 24.1% of the total cumulative incremental oil production of polymer-surfactant flooding. On the other hand, watercut rises gradually and oil production decreases during this period. In order to get a stable oil production rate, increasing the injection and production rates is the conventional measure, which has been widely applied in oil fields of China (Dong et al., 2008).



(a) Watercut and incremental oil production (b) Injectivity index and liquid production

Fig. 3. Production curves of Gudong 7th reservoir

Figure 3(b) represents the water injectivity index per meter and dimensionless daily liquid production rate of Gudong 7th reservoir during polymer and surfactant flooding. Water injectivity index per meter, used to describe the injectivity of the well, is defined as the injection rate per pressure and per effective thickness. Dimensionless daily production rate, used to describe the productivity of the well, is defined as the ratio of the daily production rate to the initial daily production rate, when polymer and surfactant flooding begins. From this figure, we can see that due to the high viscosity of the injected chemical solution, both the injectivity and productivity of the wells decrease at the chemical injection period (Bennetzen et al., 2014; Zerpa et al., 2005). The water injectivity index per meter has decreased by 34.6% and the dimensionless daily production rate decreased by 37.0%. However, at the subsequent water flooding period, along with the production of the injected viscous chemical solution, the injectivity and productivity of wells recover gradually, providing the feasibility of increasing the injection and production rates. For Gudong 7th reservoir, the water injectivity index per meter increased by 113.8% and the dimensionless daily production increased by 38.1% at subsequent water flooding period.

Table 2. Oil recoveries of the cases with different injection/production rates

Percent of the increase, %	0	10	20	30	40
Injection rate, m^3/d	898	988	1078	1167	1257
Production rate, m^3/d	954	1049	1145	1240	1336
Oil recovery, %	47.65	47.670	47.714	47.692	47.683
Enhanced oil recovery, %	0	0.020	0.064	0.042	0.033

Based on the history matched model, the oil recoveries of cases with different injection/production rates at the subsequent water flooding period are calculated by using software CMG and are listed in Table 2. For the case with no increase of the injection/production rate, the injection rate and production rate are 898 m3/d and 954 m3/d respectively and the final oil recovery is 47.65%. For the cases with increase of the injection/production rates, the injection/production rates for all wells increased at a same percent. From the results, we can see that on one hand, increasing the injection/production rate of the subsequent water flooding period is effective to improve the oil recovery, and it yields the highest oil recovery, when the percent of the increase equals 20%. On the other hand, the remaining geological reserves, watercuts and interwell injectivity of the well groups significantly vary after long time water flooding and chemical injection. If we neglect these influential factors and simply increase the injection/production rates for all wells at a same percent, the effect is limited and the highest enhanced oil recovery is only 0.06%.

INJECTION/PRODUCTION RATE ALLOCATION METHOD

The basic procedures of the injection/ production rate allocation method are as follows:

1- Collect the injection/production rates of all wells after polymer-surfactant injection and calculate the total injection/production rate of the reservoir according to the percentage of the increase.

2- Divide the reservoir into several well groups according to the locations of the injection and production wells.

3- Allocate the well injection rates according to the remaining geological reserves and average watercuts of the well groups.

4- Calculate the total production rate of each well group according to the injection-production ratio.

5- Calculate the interwell connectivity according to the curves of polymer concentration of the production wells.

6- Allocate the total well production rate of each well group to its belonging production wells according to the interwell connectivity and watercuts.

7- Calculate the final production rate of each production well, i.e., if one production well is located at several well groups at the same time, its final production rate equals the summation of the sub-production rates obtained from these well groups.

Injection rate allocation method

The injection rate allocation method mainly considers the remaining geological reserves and average weatercuts of the well groups. The higher the remaining geological reserve is and the lower the watercut is, the bigger is the potential to gain more oil out, thus the larger the allocated injection rate is.

If we consider only the remaining geological reserves, then the injection rate of each well group can be calculated as follows:

$$I_j^{'} = \frac{N_j}{N} \cdot I_t \tag{1}$$

Where, N is the remaining geological reserve of the reservoir, 10^4t; N_j is the remaining geological reserve of well group j, 10^4t; I_t is the total injection rate of the reservoir, m3/d.

If we consider only the average watercut, then the injection rate of each well group can be calculated as follows (Liu et al., 2017):

$$I_j^{''} = \frac{10^{a\left(\overline{f}_w - f_{wj}\right)}}{\sum_{j=1}^{n} 10^{a\left(\overline{f}_w - f_{wj}\right)}} \cdot I_t \tag{2}$$

Where, $\overline{f}_w$ is the average watercut of the reservoir, %; f_{wj} is the average watercut of the subordinate production wells of well group j, %; a is a constant which controls the influence of average watercut on the allocation result.

In Equation (2), the numerator represents the deviation of watercut of well group j (f_{wj}) to the average watercut of the reservoir ($\overline{f}_w$) and the denominator represents the sum of the deviations of all well groups. The value of a lies between 0 and 1 and the closer the value of a to 1 is, the larger the difference of the results is.

The final well injection rate is weighted average sum of Ij’ and Ij”, which is expressed as follows:

$$I_j = xI_j^{'} + (1-x)\, I_j^{''} \tag{3}$$

Where, x is the weighted coefficient.

Production rate allocation method

Once the injection rate of each well group is determined, the total production rate of the subordinate production wells of the well group can be calculated according to the injection-production ratio as follows:

$$Q_i = I_i / S \tag{4}$$

Where, I_i is the total injection rate of well group i, m^3/d; S is the injection-production ratio.

The production rate allocation method mainly considers the interwell connectivity and watercuts of the wells. The lower the interwell connectivity and watercut are, the less the risk of water channeling is and the bigger is the potential to gain more oil out, thus the larger the allocated production rate is.

The conventional measuring methods of the interwell connectivity include tracer test, interference well test, artificial neural network method, etc. However, these methods are usually very complicated or must disturb the normal production process. For polymer-surfactant flooding reservoir, the produced mass of polymer from the production well is easily obtained, and if we treat the injected polymer as a tracer, the interwell connectivity between the production well and injection well can be obtained by analyzing the produced polymer mass data.

The mass of produced polymer is closely related to the production rate, i.e., if the production rate is very high, the mass of produced polymer is also probably high. Thus, if we want to compare the mass of produced polymer between wells, the influence of the production rate should be eliminated. Therefore, we take the polymer concentration of the produced fluid (the ratio of the mass of produced polymer to the liquid production rate) as the index to measure the interwell connectivity between the production well and injection well.

$$C_p = {R_p}/{R_L} \tag{5}$$

Where, C_p is the polymer concentration of the produced fluid, kg/m^3; R_P is the mass of the produced polymer per day, kg/d; R_L is the fluid production rate, m^3/d.

Figure 4 is the schematic plot of the concentration of the produced fluid. As shown in this figure, after a lag time, the polymer concentration increases gradually to the peak and then decreases. The concentration of the polymer and the lag time are both related to the interwell connectivity. The better the connectivity between wells, the larger the polymer concentration and the lag time is shorter. Therefore, we introduce a weighting function f, which, takes time i as variable and then the weighted cumulative polymer concentration can be calculated as follows:

$$C_{pt} = \sum_{i=1}^{N} C_{pi} f(i) \tag{6}$$

Where, C_{pt} is the weighted cumulative polymer concentration, kg; C_{pi} is the average polymer concentration at time interval i, kg/m^3; N is the number of time intervals; $f(i)$ is the weighting function.

From the above analysis, we know that the earlier the breakthrough of the polymer is, the higher the connectivity is. Therefore, the weighting function must be inversely proportional to time. In similarity, the formula of the weighting function was chosen as (Zhao et al., 2010; Wang et al., 2012):

$$f(i) = 1/i\,,\ i = 1,2,...,N \tag{7}$$

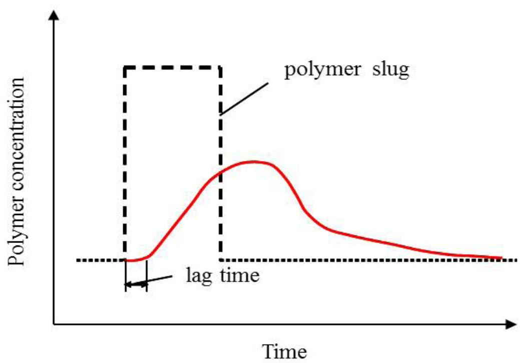


Fig. 4. Schematic plot of polymer concentration curve of the production well

Then the interwell connectivity between the production well and injection well can be calculated as follows:

$$w_j = C_{pt}^j \Big/ \sum_{j=1}^{n} C_{pt}^j \tag{8}$$

Where, wj is the interwell connectivity between the injection well and production well j; C_{pt}^j is the weighted cumulative polymer concentration of well j, kg; n is the number of the production wells in the well group.

If we consider only the interwell connectivity, then the sub-production rate of well j in well group i can be calculated as follows:

$$Q_{ij}^{'} = \frac{10^{b\cdot(\overline{w}_i - w_{ij})}}{\sum_{j=1}^{n} 10^{b\cdot(\overline{w}_i - w_{ij})}} \cdot Q_i \tag{9}$$

Where, $\overline{w}_i$ is the average interwell connectivity of well group i; w_{ij} is the interwell connectivity of production well j in well group i; b is a constant, which controls the influence of interwell connectivity on the result. The value of b lies between 0 and 1 and the closer the value of b to 1 is, the larger the difference of the results is.

If we consider only the average watercut, then the sub-production rate of well j in well group i can be obtained by the following formula:

$$Q_{ij}^{"} = \frac{10^{c \cdot \left(\bar{f}_{wi} - f_{wij}\right)}}{\sum_{i=1}^{n} 10^{c \cdot \left(\bar{f}_{wi} - f_{wij}\right)}} \cdot Q_i \tag{10}$$

Where, $\bar{f}_{wi}$ is the average watercut of all production wells in well group *i*,%; f_{wij} is the watercut of production well j in well group *i*, %; c is a constant which controls the influence of watercut on the result. The value of c lies between 0 and 1 and the closer the value of *c* to 1 is, the larger the difference of the results is.

The final sub-production rate of the production well *j* in well group *i* is the weighted average sum of Q_{ij}' and Q_{ij}" which is expressed as follows:

$$Q_{ij} = yQ_{ij}^{'} + (1-y)Q_{ij}^{"} \tag{11}$$

Where, y is the weighted coefficient.

The final production rate of the production well *j* is the summation of all sub-production rates obtained from all well groups it belongs to.

RESULT ANALYSIS

Optimization of the weighted coefficients

There are five weighted coefficients including a in Equation (2), *x* in Equation (3), *b* in Equation (9), *c* in Equation (10) and y in Equation (11). All these five numbers have the same ranges of 0 to 1. For each coefficient, it was divided in to 21 levels including 0, 0.05, 0.1, 0.15…1 and the interval between the adjacent two levels was 0.05. Single factor analysis method was used to optimize the values of these coefficients (Wang et al., 2012).

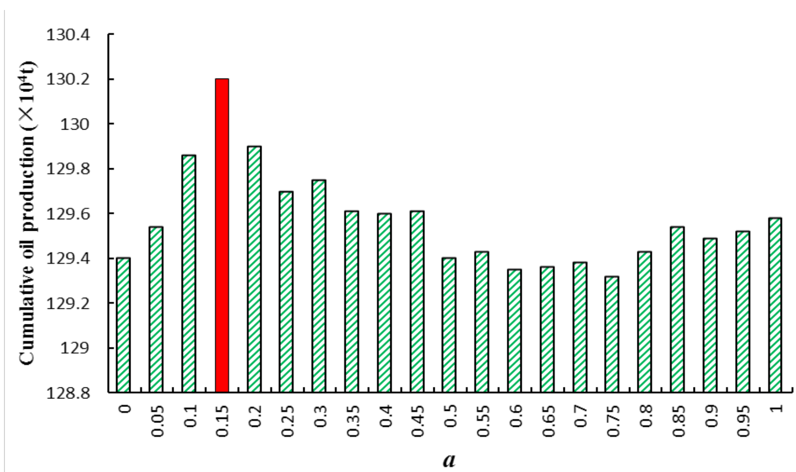
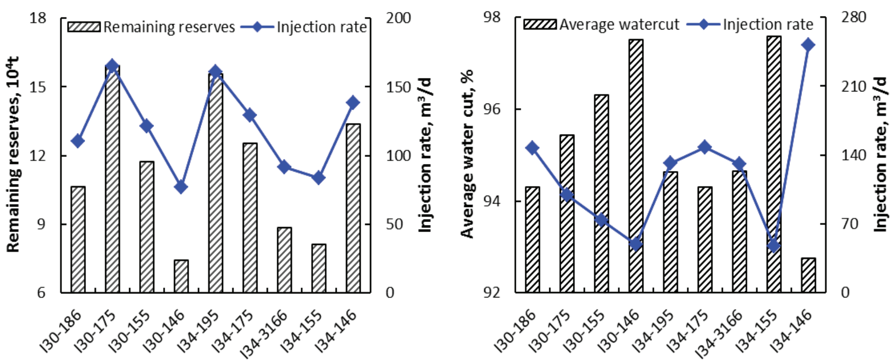


Fig. 5. Cumulative oil productions of cases with different values of a

In the base case, all these five coefficients were taken as 0.5 and then the value of each coefficient was changed from 0 to 1 successively. Therefore, for each coefficient, 21 simulations should be conducted by using CMG and according to the comparison of the final oil productions of these cases, the optimal value of the coefficient was obtained. Therefore, there was a total of 21×5=105 simulations conducted. Figure 5 is the cumulative oil productions of cases with different values of a and from this figure, we can see that when a equals 0.15, the biggest cumulative oil production is achieved. In the same way, the optimal *b*, *c*, *x* and y were obtained and their values are 0.8, 0.1, 0.6, 0.8 respectively.

Results of injection rate allocation

The percentage of increase of injection rate and production rate is 20% and the injection-production ratio is kept the same. Therefore, the total injection rate of 9 injection wells increases from 898m^3/d to 1078m^3/d and the total production rate of 16 production wells increases from 954m^3/d to 1145m^3/d.



(a) Consider the remaining geological reserves (b) Consider the average watercut (a=0.15)

Fig. 6. Injection rate allocation result when considering only one parameter

Centered on the injection well, the reservoir is divided into 9 well groups. Figure 6 shows the allocation result, when only considering one factor. From this figure, we can see that, similar to the analysis carried out before, after water flooding and chemical injection period, the remaining reserves and watercuts of the well groups differ greatly, i.e., the reservoir shows strong heterogeneity. If we simply increase the injection/production rate of all wells at a same percent, some well groups with small remaining reserves and high watercuts will not gain a good performance leading to a poor economic benefit. Figure 7 shows the final allocation result, considering both remaining geological reserves and watercuts. From this figure, we can see that the final allocated injection rates of all groups vary greatly. For example, the well group I34-146 has a large remaining reserve and low watercut and its allocated injection rate reaches up to 183.6m^3/d. However, the well group I30-146 has a small remaining reserve and high watercut and its allocated injection rate is only 65.7m^3/d.

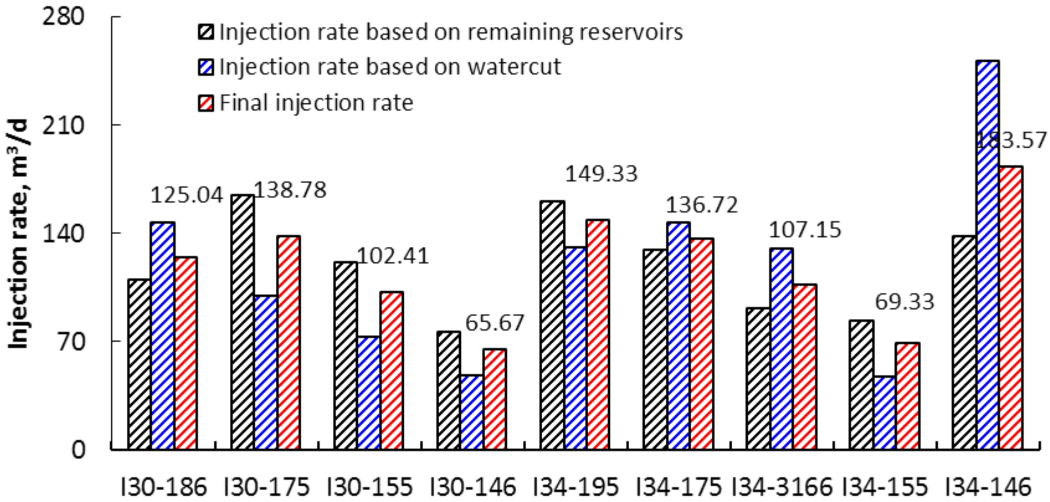
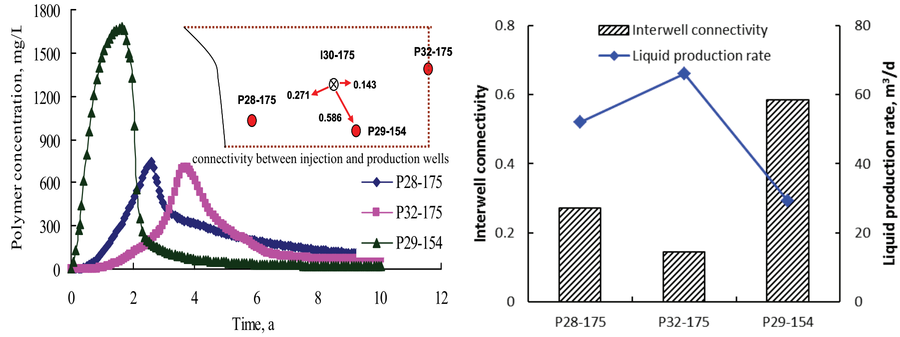


Fig. 7. Final allocation result both considering reserves and watercuts (x=0.6)

Results of production rate allocation

According to the polymer concentration curves of the production wells, the interwell connectivity between the production well and injection well is calculated. Taking well group I30-175 for example, the calculation process and result analysis of interwell connectivity between the injection well I30-175 and production wells including P28-175, P29-154 and P32-175 are analyzed.

We take ten years' concentration curves to calculate the interwell connectivity. The concentration curves of three production wells are shown in Figure 8(a). From this figure, we can see that the three curves show quite different properties. The lag time of well P29-154 is quite short and the polymer concentration increases sharply, which indicates a good connectivity between it and the injection well. However, the curve of well P32-175 shows opposite properties, i.e., the lag time is quite long and the polymer concentration increases slowly, which indicates a poor connectivity. We take the time interval equaling 6 months and thus 20 points are obtained from each curve. According to the method mentioned above, the interwell connectivity between three production wells and the injection well are calculated and also plotted in Figure 8(a). In this figure, the arrow direction represents the flow direction and the arrow length represents the values of interwell connectivity. As analyzed above, the interwell connectivity is quite different for different wells. The interwell connectivity of P32-175 is only 0.143 and that of P29-154 reaches up to 0.586 which is 4.1 times of 0.143.



(a) Concentration curves (b) Corresponding sub-production rates (b=0.8)

Fig. 8. Interwell connectivity and the corresponding sub-production rates

Fig. 9. Sub-production rates based on watercut (c=0.1)

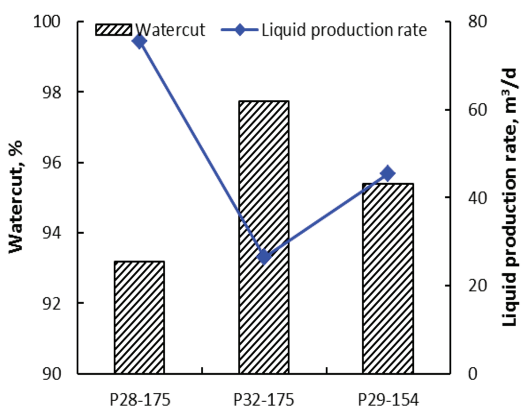


Table 3. Final sub-production rates of the production wells in well group I30-175 (y=0.8)

	P28-175	P32-175	P29-154
Pro(c), m^3/d	52.1	66.0	29.2
Pro(w) m^3/d	75.6	26.4	45.4
Pro(F) m^3/d	56.8	58.1	32.5

The allocated injection rate of well I30-175 is 138.78m^3/d. Therefore, according to the injection-production ratio which equals 0.94, the summation of the sub-production rates of three production wells should be 147.64m^3/d. The sub-production rates, when considering only interwell connectivity (denoted by Pro(c) in Table 3) or watercut (denoted by Pro (w) in Table 3) are calculated and shown in Figure 8(b) and Figure 9 respectively. At last, the final sub-production rates (denoted by Pro(F)) of the three production wells are calculated and listed in Table 3. From the table, we can see that the well P32-175, which has a low interwell connectivity gains the biggest sub-production rate and the well P29-154 with high interwell connectivity and watercut gains the smallest sub-production rate.

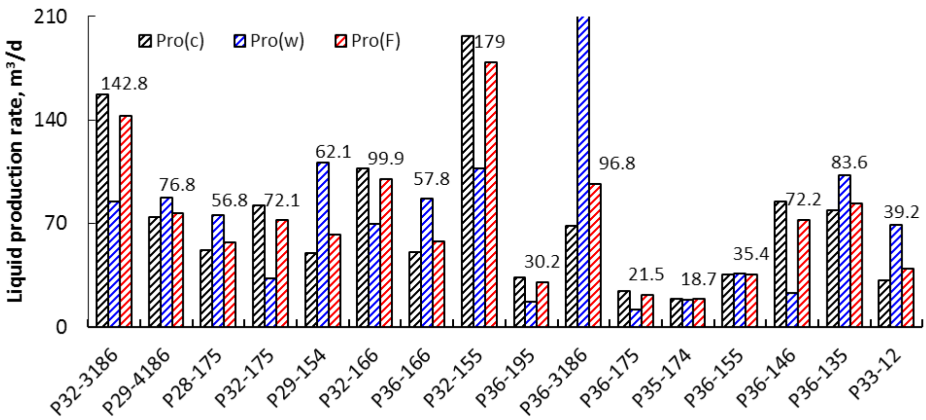
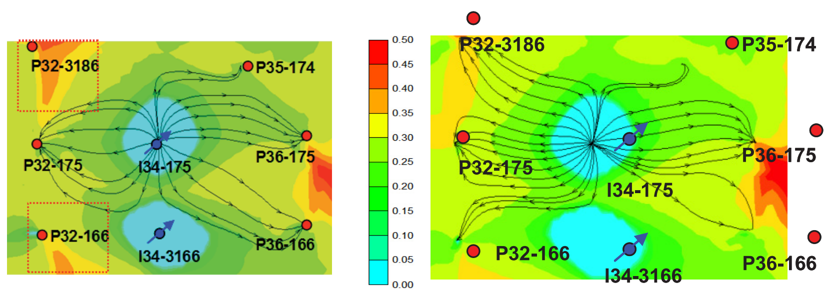


Fig. 10. Allocated production rates of all production wells

If we repeat the above process to all well groups, then the sub-production rates of all wells are obtained. If one well is located in several well groups, its final production rate equals the summation of all sub-production rates. The allocated production rates of all wells are shown in Figure 10. After long time water flooding and chemical injection, the interwell connectivity and watercuts of the wells differ greatly. Therefore there are big differences between the production rates. For example, the allocated production rate of well P32-155, which has a low interwell connectivity and watercut reaches up to 179.0m^3/d. However, that of well P35-164, which has a high interwell connectivity and watercut is only 18.7m^3/d.

Analysis of the performance



(a) The conventional method (b) The new method

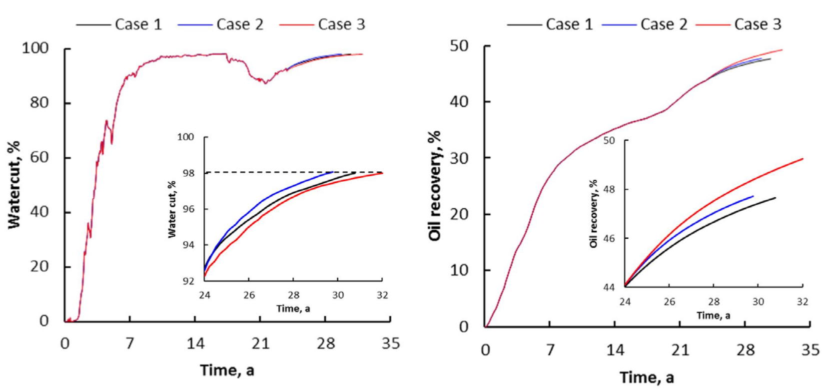
Fig. 11. Streamline distribution of layer 1 after 7 years' development

The performance of the allocation method proposed in this paper is simulated by using CMG. For comparison, the case with conventional allocation method (increase the injection/production rates of all wells at a same percent) is also simulated. Taking well group I34-175 for example, the streamline distributions of the first layer after 7 years' development is shown in Figure 11. The background image is water saturation map. From this figure, we can see that the streamlines are also re-allocated after the implementation of the new method. After long time water flooding and chemical injection period, good interwell connectivity has been formed between the injection well I34-175 and production wells including P32-175, P35-174, P36-175 and P36-166. Therefore the streamlines mainly belong to these wells and the corresponding water saturation is low between the injection well and these production wells. However, the wells P32-3186 and P32-166 nearly have no streamlines and two "sweet spots" with high oil saturations (the enclosed areas by two rectangles in Figure 11(a)) are formed between the injection well and these two wells. Table 4 shows the detailed percentage of streamlines the wells owned. Combining Figure 11 and Table 4 together, we can see that due to the high watercut and interwell connectivity, the number of streamlines between the injection well and P36-166 become smaller. However, relatively high production rates are obtained for well P32-3186 and P32-166 due to the low interwell connectivity of these two wells, and after the adjustment, new streamlines are formed between the injection well and these two wells (from 0 to 0.05 for P32-166, from 0 to 0.17 for P32-3186), leading to an oil saturation decrease in the "sweet spots". In other words, the streamline distribution is optimized after the re-allocation of the injection/production rate.

Table 4. Percent of streamlines owned to the wells

	P32-166	**P32-175**	**P35-174**	**P36-166**	**P36-175**	**P32-3186**
Conventional method, %	0	0.47	0.03	0.35	0.15	0
New method, %	0.05	0.41	0.01	0.11	0.25	0.17

Figure 12 shows the comparison of watercuts and oil recoveries of different cases. Besides the conventional method (Case 2) and the new method (Case 3), the curves of the case with no increase of injection/production rate (Case 1) are also plotted. Each simulation is stopped, when the watercut of the reservoir reaches 98%. From this figure, we can see that the watercut of conventional method is the highest. This is because water channeling is easily to occur, if we just increase the injection/production rate without considering the interwell connectivity of wells. On the contrary, based on the reasonable reallocation, the new method gains the lowest watercut, though the injection/production rate is also increased. As shown in Figure 12(b), the enhanced oil recovery of the conventional method is only 0.06% and that of the new method reaches up to 1.53%. In other words, the new injection/production rate allocation method which considers remaining geological reserve, watercut and interwell connectivity is helpful in getting a better performance for polymer/surfactant flooding reservoir.



(a) Watercuts (b) Oil recoveries

Fig. 12. Comparison of watercuts and oil recoveries of different cases

CONCLUSIONS

(1) The polymer concentration of the production well and lag time are both related to the interwell connectivity. The better the connectivity between wells is, the larger the polymer concentration and the shorter the lag time are. According to this law, the polymer is treated as a tracer and a method to obtain interwell connectivity is proposed.

(2) An injection/production rate allocation method is proposed. The injection rate allocation method considers the remaining geological reserves and average watercuts of the well groups, while the production rate allocation method considers the interwell connectivity and watercut of the production well. Compared with the conventional method, the method proposed in this paper combined the static and dynamic parameters together.

(3) After long time of water flooding and chemical injection, the remaining reserves, watercuts and interwell connectivity differ greatly between well groups. Therefore the enhanced oil recovery of the conventional method, which simply increases the injection/production rates for all wells at a same percent is only 0.06%. However, that of the method proposed in this paper reaches up to 1.53%. In other words, the new injection/production rate allocation method, which considers remaining geological reserve, watercut and interwell connectivity together, is helpful in getting a better performance for polymer/surfactant flooding reservoir.

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