Sensitivity Analysis and Optimization of Technological Parameters During Coupled Liquid CO_2 Hydraulic Fracturing/Huff and Puff Treatment in Tight Oil Reservoirs*

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Abstract

Tight oil reservoirs are currently a primary focus of exploration and development activity all over the world. Fracturing treatment and water/gas flooding are two effective ways to boost recovery. However, damage induced by water-rock interaction, including swelling and migration of clay minerals, capillary water blockage, as well as softening and argillitization of rock exerts great negative effects on the productivity. As no water phase is present, CO_2 is often used as treatment fluid in both stimulation and EOR operations, which has provided not only an excellent opportunity to improve oil recovery, but also a chance to sequester CO_2 to reduce the environment footprint.

Coupled liquid CO_2 hydraulic fracturing/huff and puff treatment is a combination of CO_2 stimulation and CO_2 EOR, aiming to maximize the productivity of tight oil reservoirs. The major difference lies in soaking time after CO_2 injection is completed, which is not incorporated in the hydraulic fracturing operation. In this work, we develop an analytical procedure and methods for analyzing technological parameters during coupled liquid CO_2 hydraulic fracturing/huff and puff treatment. Several parameters, such as fracture length, fracture conductivity, fracture spacing, CO_2 injection volume, soaking time, and bottom hole flowing pressure (BHFP) are studied. A compositional numerical model is employed to simulate the flow process and interaction of CO_2 and oil in the reservoir. The cubic Peng-Robinson equation of state is used for phase behavior calculations. The orthogonal analysis method is then utilized to analyze the sensitivity of technological parameters and optimization is implemented accordingly.

The results show that the production rate of coupled liquid CO_2 hydraulic fracturing/huff and puff treatment is better than either CO_2 hydraulic fracturing treatment or CO_2 huff and puff treatment used alone. From the perspective of cumulative recoverable reserves, it is found that BHFP is the most important parameter, while soaking time has minimal impact. With the increasing of the BHFP, cumulative recoverable reserves

decline. With the extension of soaking time, the production rate is increasing at the beginning, then it reaches a stable stage, then actually declines. The half-length, spacing and conductivity of fractures are also major factors influencing the production performance. The optimum intervals of these factors are all important.

A case study is conducted based on a real geologic model afterward, to optimize the technological parameters during coupled liquid CO_2 hydraulic fracturing/huff and puff treatment, which has valuable guiding significance for design and optimization of field operation.

Introduction

Tight oil reservoirs are considered as reservoirs with an average permeability below 1 mD. Field experience indicates that primary depletion of tight oil formation recovers only 5 to 10% of OOIP (Mansour et al., 2017; Holm, 2013). Over the past decades or so, drilling of horizontal, multi-staged hydraulically fractured wells has been established as the suitable way of recovering oil from such reservoirs (Zhang et al., 2015). However, due to low mobility of the oil and rather quick pressure interference between the fractures, the depletion of the reservoir is mostly confined to the near fracture space and the initial high production rates will rapidly decrease with time (Yu et al., 2014.). Moreover, damage induced by water-rock interaction, including swelling and migration of clay minerals, capillary water blockage, as well as softening and argillitization of rock, exerts great negative effects on the productivity (Xu et al., 2013).

As no water phase is present, CO_2 is often used as a treatment fluid in both stimulation and EOR (Enhanced Oil Recovery) operations, which has provided not only an excellent opportunity to improve oil recovery, but also a chance to sequester CO_2 to reduce the environmental footprint (Sun et al., 2017). Liquid CO_2 hydraulic fracturing, which uses pure CO_2 as the hydraulic fracturing fluid, is a perfect way to avoid the damage caused by fluid-rock interaction in conventional hydraulic fracturing. The energy supplement for reservoir during pumping enables flowback more easily, resulting in quick preparation of the well for production (Arnold, 1998). Since the first liquid CO_2 hydraulic fracturing treatment in 1981, this stimulation method has been employed in various reservoirs, including shale gas, tight oil, and coal bed methane formations (Li et al., 2017). Compared with water-based fluid hydraulic fracturing and foam-based fluid hydraulic fracturing, the production rate of liquid CO_2 hydraulic fracturing is better (Gupta and Bobier, 1998). The first liquid CO_2 hydraulic fracturing treatment in a tight oil formation in China was conducted in 2014. The treatment lasted 5 days and the production rate increased from 1.2 ton/d before treatment to 9.7 ton/d after stimulation (Wang et al., 2016). CO_2 huff and puff treatment is another highly adopted EOR method in tight oil reservoirs, accounting for 23.6% of the total EOR oil production in U.S.A. and Canada. For this process, CO_2 is pumped into formation first, then the well is shut-in for a few days or months, which is the soaking time, then the well is reopened for production. The main function mechanism of CO_2 EOR lies in the interaction of oil-CO_2 during the soaking time. CO_2 dissolves in oil, so the viscosity and the interfacial tension is decreased and the oil mobility is enhanced accordingly. Gas dissolved in oil can also act as drive energy for oil to flow into the wellbore through extra-low permeability tight formations (Shaw et al., 2002). Indoor laboratory experiments and numerical simulations have been studied frequently in past few years and many successful cases can prove the efficiency of this method (Tuan Thanh Phi, 2016).

This study put forward a new technology in a tight oil formation, coupled liquid CO_2 hydraulic fracturing/huff and puff treatment, combining the liquid CO_2 hydraulic fracturing and CO_2 huff and puff creatively, aiming to exert each advantage into this process and maximize the productivity of tight oil reservoirs. As illustrated in Figure 1, the process can be described as follows. First, liquid CO_2 is pumped into the formation as a hydraulic fracturing fluid to create fractures, carrying proppant to keep the fractures open. When the stimulation process is completed, the well is shut-in for a period to let the interaction between oil and CO_2 take place sufficiently. Then the well is reopened for production. As an innovative stimulation method, the factors influencing the results have not been studied and the sensitivity of each factor is not fully known. In this work, we develop an analytical procedure and methods for analyzing technological parameters during coupled liquid CO_2 hydraulic fracturing/huff and puff treatment. Based on geologic and formation parameters of A Oilfield in China, a numerical simulation model of this newly proposed method was established and the sensitivity of various parameters was investigated.

Method

Establishment of Numerical Model

Based on the geologic data, reservoir parameters and formation fluid characteristics of the researched area of interest, a tight oil reservoir geologic model was established with ECLIPSE software (Fu et al., 2015). A multi-staged hydraulic fractured horizontal well was set in the model and the fracture dimension was observed and the simulation results obtained from stimulation software MEYER (Stegent et al., 2011). As illustrated in Table 1, the reservoir geologic model parameters were designed as real data of the A Oilfield. The model was meshed with structured grid and the facture was dealt with LGR (local grid refinement) module in ECLIPSE. There were 160 grids in the X direction and 80 grids in the Y direction, with each grid representing 10 m. Three grids were set in the Z direction and each grid representing 1 m respectively.

Simulation of CO_2-Oil Interaction and Phase Behavior

It is crucial to ensure that the fluid properties used in the simulation model be consistent with the actual situation of the reservoir for accurate the tight oil reservoir numerical simulation. Composition models of ECLIPSE software were used to study the interaction of oil and injected CO_2. Based on tight oil properties of A Oilfield, PVTi module of ECLIPSE was utilized to establish the fluid model of reservoir. This module can calculate the minimum miscible pressure (MMP) of CO_2 and oil under different conditions, such as multiple contact dynamic miscibility and once contact dynamic miscibility. In the process of calculation, a pseudo-ternary phase diagram was generated to help explain the miscibility results (Kalra and Wu, 2015). Under the conditions of constant pressure and temperature, gas phase and fluid phase simulation before and after contact can be realized by drawing the equilibrium liquid phase diagram and gas composition phase diagram in a certain pressure range (Halpern, 1986). Flash calculation can be used to obtain the two phase envelop, which can be employed to simulate the immiscible or miscible displacement process. In order to describe the relationship among volume, temperature and pressure, the cubic Peng-Robinson equation of state is chosen for phase behavior calculations. Various fluid phase-related numerical match experiments were conducted for fluid simulation accuracy, including spit and combination of oil composition, CCE experiment match, Swelling experiment match, DL experiment match, CO_2-oil miscible simulation, and so on. Figure 2, Figure 3, Figure 4, Figure 5, and Figure 6 show numerical simulation match results of fluid properties. High pressure physical property parameters of oil phase and gas phase is displayed in Table 2.

It is well known that different reservoir properties, fracture dimensions and production systems will lead to different production results. In order to study the effect of different parameters on the production rate, different parameter settings, such as fracture length, fracture conductivity, fracture spacing, CO_2 injection volume, soaking time, and bottom hole flowing pressure (BHFP) were simulated in the model.

According to hydraulic fracturing theory, a determined amount of fracturing fluid injected means a definite fracture half-length if other conditions are fixed. Taking the corresponding relationship of fracture length and CO_2 injection volume into account, we chose the fracture half-length as a research target in the optimization of parameters. Single factor analysis was conducted at first.

The production rate of different parameter combinations was calculated and results were compared. At the basis of the results of single factor analysis, the orthogonal analysis method was then utilized to analyze the sensitivity of technological parameters. Based on the orthogonal analysis results, the most important parameter and the best parameter combination for production were obtained, accordingly.

Results and Discussion

Single Factor Analysis

Taking the cumulative production of 200 days as an optimization objective, sensitivity analysis of key factors, including fracture conductivity, fracture half-length, fracture count, soaking time and BHFP, were implemented to provide reference for stimulation design.

a) Fracture Conductivity

In this section, numerical model parameters were designed as follows. Fracture count was 7, fracture half-length was 120 m, soaking time was 7 days, BHFP was 5 MPa. Based on simulation results of Meyer, CO_2 injected volume was 2940 m^3 for 120 m fracture length. Cumulative production of various fracture conductivities was calculated. As shown in Figure 2, the cumulative production is increased with the increase of fracture conductivity. The optimum conductivity is 30 $\mu m^2 \cdot cm$.

b) Fracture Half-Length

In order to investigate the effect of fracture half-length on the cumulative production, six kinds of fracture half-length were set and other parameters were designed as follows. Fracture count was 7, fracture conductivity was 30 $\mu m^2 \cdot cm$, soaking time was 7 days, BHFP was 5 MPa. Cumulative production of various fracture half-length was calculated and displayed in Figure 3. As shown in Figure 3, at first the cumulative production is increased with the increasing of fracture half-length. The increasing rate of production becomes slower when fracture half-length is increased to a certain value. In other words, optimum fracture half-length is presented. The optimum fracture half-length is 120 m.

c) Fracture Count

In this part, numerical model parameters were designed as follows. Fracture conductivity was 30 $\mu m^2 \cdot cm$, fracture half-length was 120 m, soaking time was 7 days, BHFP was 5 MPa. Cumulative production of various fracture counts was calculated and displayed in Figure 4. As shown in Figure 4, the cumulative production is increased with the increasing of fracture count. Optimum fracture count must be considered because fracture interference will emerge if too many fractures are created. The optimum fracture count is 7.

d) BHFP

In order to investigate the effect of BHFP on the cumulative production, five rates of BHFP were set and other parameters were designed as follows. Fracture count was 7, fracture conductivity was 30 $\mu m^2 \cdot cm$, soaking time was 7 days, fracture half-length was 120 m. Cumulative production of various BHFP was calculated and is displayed in Figure 5. As shown in Figure 5, the cumulative production is decreased with increasing BHFP. But the BHFP must be larger than a certain value to maintain well production. In other words, optimum BHFP is presented. The optimum BHFP is 5 MPa.

e) Soaking Time

It is obvious that duration of soaking time can determined the degree of CO_2-oil interaction in the formation. In order to study the influence of soaking time on the cumulative production, five durations of soaking time, 2 d, 5 d, 7 d, 10 d, 14 d, were set for simulation. Other parameters were designed as follows. Fracture count was 7, fracture conductivity was 30 $\mu m^2 \cdot cm$, BHFP was 5 MPa, fracture half-length was 120 m. Cumulative production of various soaking time levels was calculated and displayed in Figure 6. As shown in Figure 6, at first the cumulative production is increased with the increasing of soaking time. The cumulative production reached a maximum point when the soaking time increased to a certain value. Then the cumulative production decreased with increasing of soaking time. The soaking time when the maximum cumulative production reached is the optimum soaking time. The optimum soaking time is 7 d in this case. If the soaking time is too short, CO_2 cannot solve into oil sufficiently, resulting in less effective in oil recovery enhancement. CO_2-oil interaction could be more efficient with the extension of soaking time. However, expansion energy of CO_2 is consumed excessively if the soaking time is too long (Ekhlasjoo et al., 2014; Lu et al., 2016). As illustrated in the results, sweeping area for 5 d soaking time is larger than sweeping area for 10 d soaking time. For this reason, the optimum soaking time will maximize the oil production from the tight formation.

From the simulation results mentioned above, the influence of factors on cumulative production from big to small can be ranked as BHFP, fracture count, fracture conductivity, fracture half-length, soaking time. We can also draw the conclusion that the best parameters combination is as follows. The optimum fracture conductivity is 30 $\mu m^2 \cdot cm$, the optimized fracture half-length is 120 m, fracture count is 7, soaking time is 5 d, BHFP is 5 MPa.

Three stimulation methods, including CO_2 huff and puff treatment, CO_2 fracturing treatment and coupled liquid CO_2 hydraulic fracturing/huff and puff treatment method, were implemented in the numerical model and compared to determine which method has a most promising stimulation effect in the tight oil reservoir. The parameters of No. 18 numerical experiment in Table 4 were adopted consistently. According to the relationship between fracture half-length and CO_2 injection volume, CO_2 injection volume was 2940 m^3. The comparison results are illustrated in Figure 7.

As displayed in Figure 7, the production rate of CO_2 huff and puff treatment, CO_2 fracturing treatment and coupled CO_2 hydraulic fracturing/huff and puff treatment were 1557 m^3, 1842 m^3 and 2174 m^3 respectively. The cumulative production of coupled CO_2 hydraulic fracturing/huff and puff treatment achieved the highest amount, more than the production of either CO_2 huff and puff treatment or CO_2

hydraulic fracturing treatment alone. This validates the advantage of coupled CO_2 hydraulic fracturing/huff and puff method, which can combine the advantages of CO_2 huff and puff method and CO_2 hydraulic fracturing effectively and maximize the oil production.

Case Study

Take a well in A Oilfield as example to illustrate the effect of this method. The well is a horizontal well with a lateral length 800 m. The permeability of the tight formation is 4.6 mD, porosity is 11.2%. The high pressure physical data showed that the density of the formation oil is 0.779 g/cm^3, the viscosity of the oil is 1.79 mPa·s, the formation volume coefficient 1.152, the dissolved oil and gas ratio is 36 m^3/m^3, the saturation pressure is 8.62 MPa. The formation water salinity is 11378 mg/L, the chloride ion content is 4481.6 mg/L, the water type is NaHCO3 type, the PH value is around 7. The depth of oil layer is 2400 m, the reservoir pressure is 24.3 MPa, and the temperature of is 94.7 ℃.

Based on the geologic data, the reservoir parameters and formation fluid characteristics of the well, a reservoir geologic model was established with ECLIPSE software. Compositional numerical model and block grid system are used in a model dimension of 800 m × 400 m × 10 m. Choose typical wells in this block for history matching. The parameters modified based on matching results are used for calculating of numerical models. By referring to this method, the best parameter combination is determined. The fracture stage was 8. The fracture half-length was 130 m, the spacing between fissures was 90 m, the fracture conductivity was 35 D•cm, the BHFP is 6 MPa. According to the parameters optimized, cumulative oil production of the well in 2 months is 1925 m^3, which is more than adjacent wells in the same block.

Conclusion

A workflow was presented in order to evaluate and optimize technical parameters for a newly proposed stimulation method, the coupled CO_2 hydraulic fracturing/huff and puff method, in a tight oil formation. Take real data from an oilfield for model input, composition numerical model was established and CO_2-oil interaction and phase behavior was calculated for numerical simulation. Then parameter sensitivity analysis, including single factor analysis and orthogonal analysis were implemented.

From the perspective of cumulative recoverable reserves, it is found that BHFP is the most important parameter, while soaking time has minimal impact. With the increasing of the BHFP, cumulative recoverable reserves decline. With the extension of soaking time, the production rate is increasing at the beginning, then it reaches a stable stage, then declines. The half-length, spacing and conductivity of fractures are also major factors influencing the production performance. Optimum intervals of these factors existed. Based on the simulation model established, the best parameters combination for coupled CO_2 hydraulic fracturing/huff and puff treatment for A Oilfield is optimized. The BHFP is 5 MPa, fracture half-length 120 nm, fracture conductivity is 30 nμm^2·cm, fracture count is 7, soaking time is 5 d. Combining advantages of CO_2 huff and puff method and CO_2 hydraulic fracturing technology, the production of coupled CO_2 hydraulic fracturing/huff and puff method outweighed each method respectively. This technology can maximize the oil production from tight oil formations and should be implemented in oilfields extensively to enhance the oil recovery.

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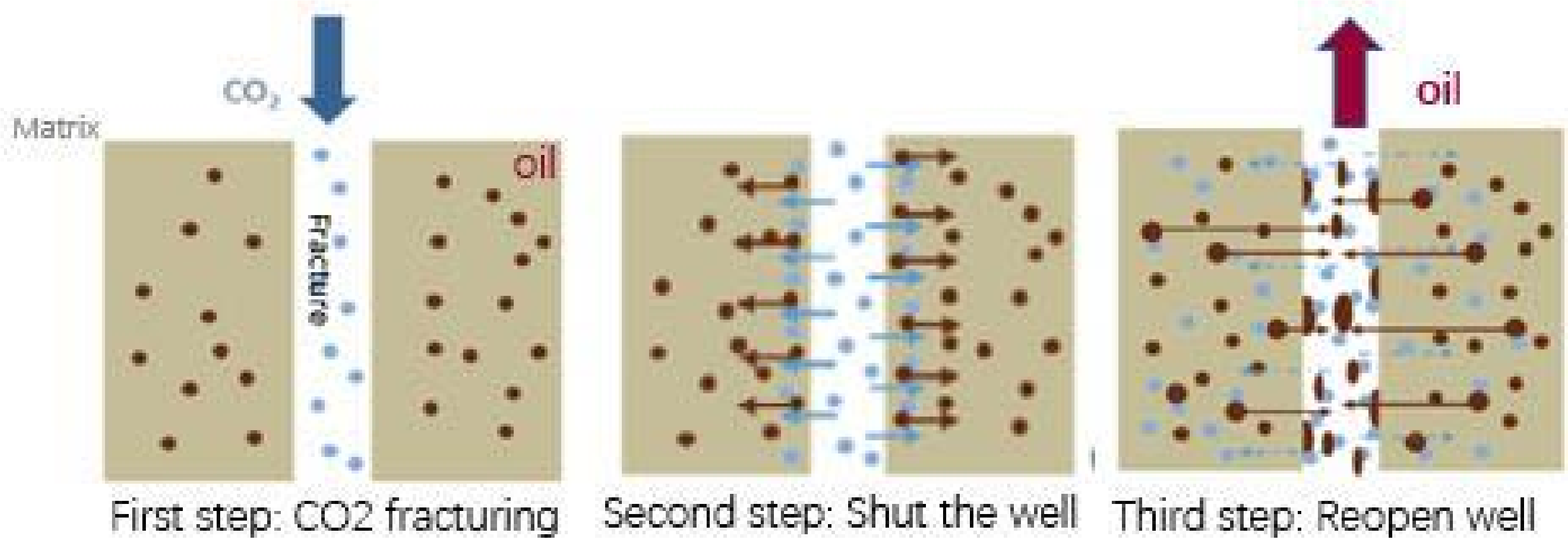

Figure 1. The process of coupled liquid CO_2 hydraulic fracturing/huff and puff treatment.

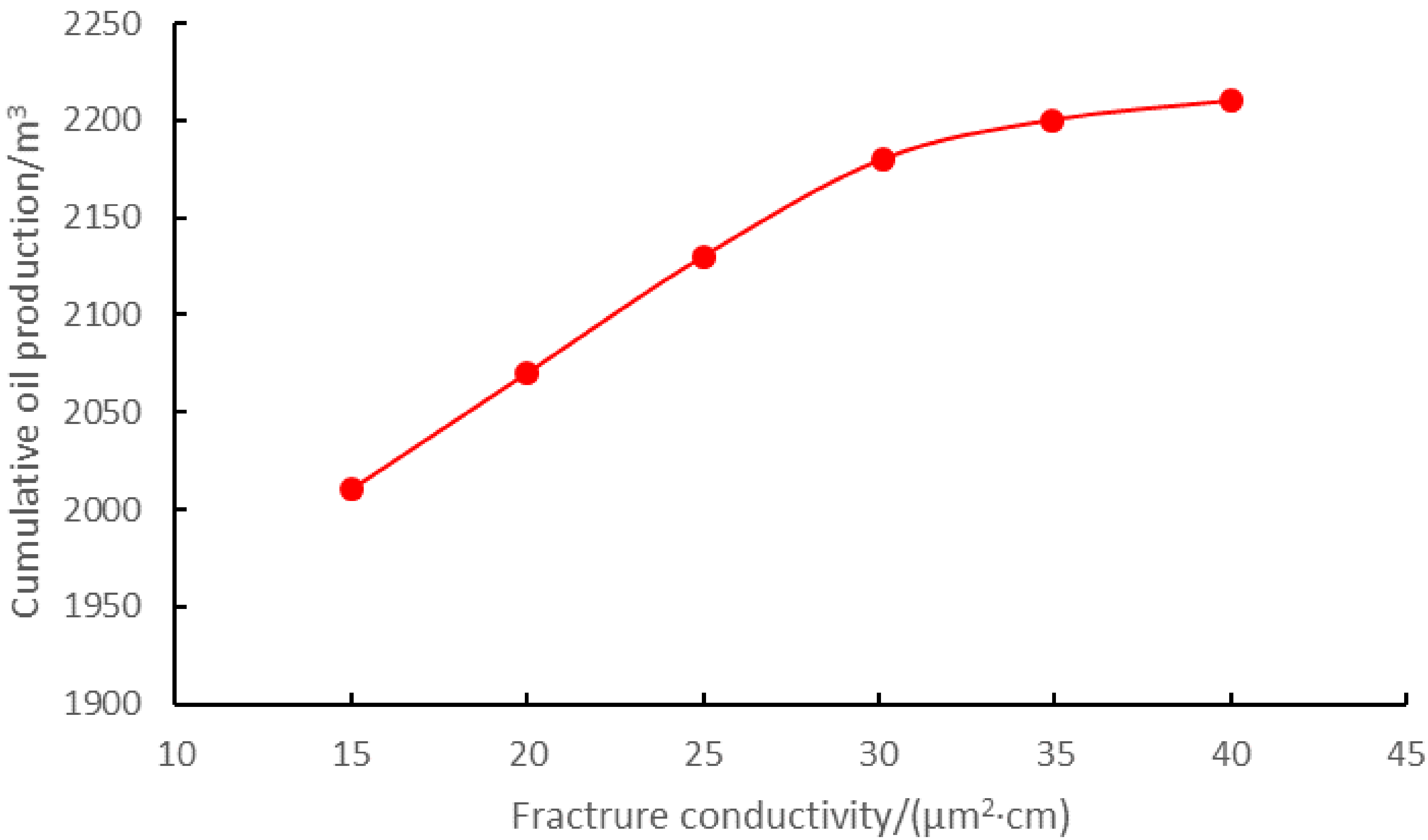

Figure 2. The optimization of fracture conductivity.

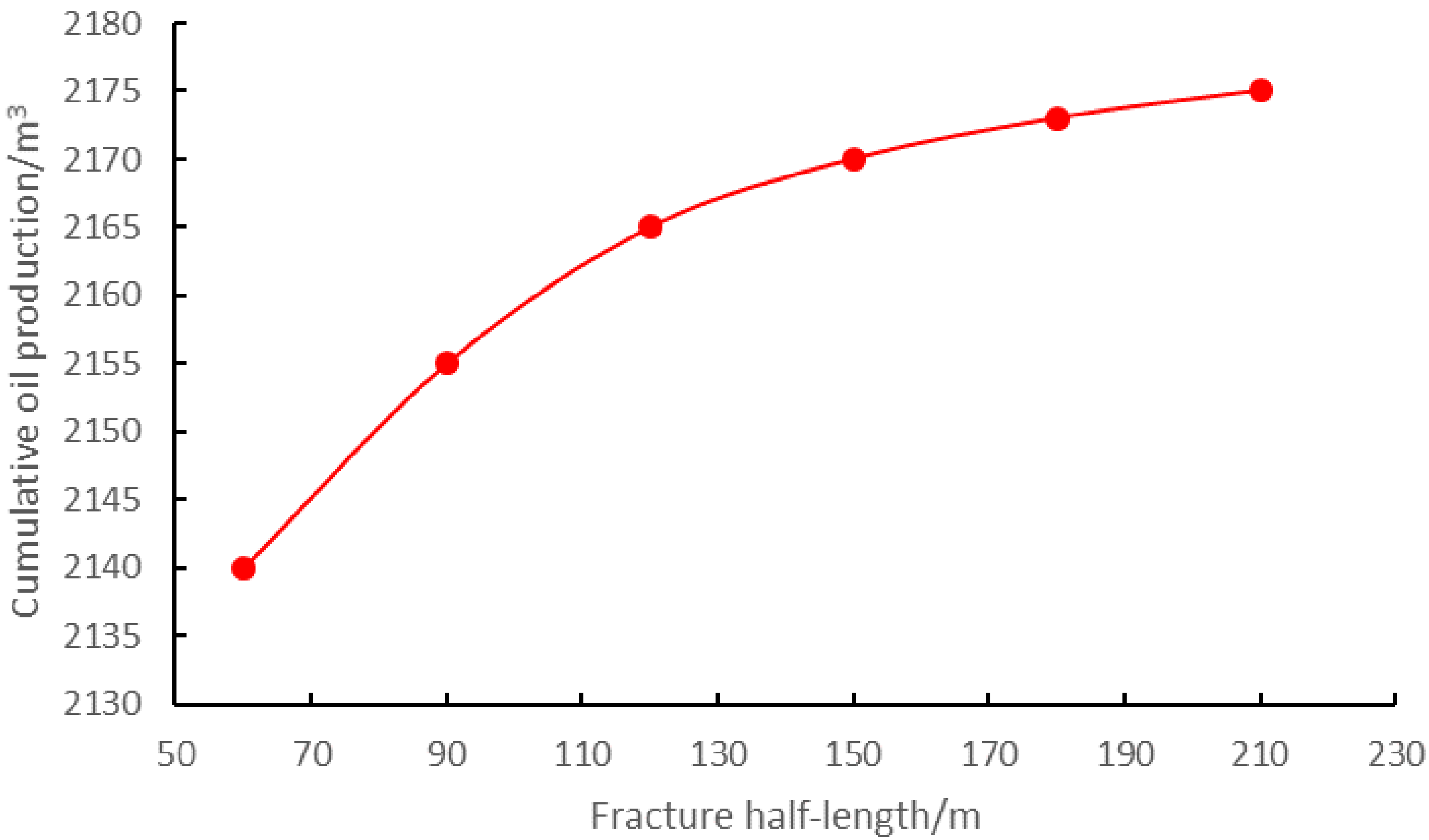

Figure 3. The optimization of half-length of fracture.

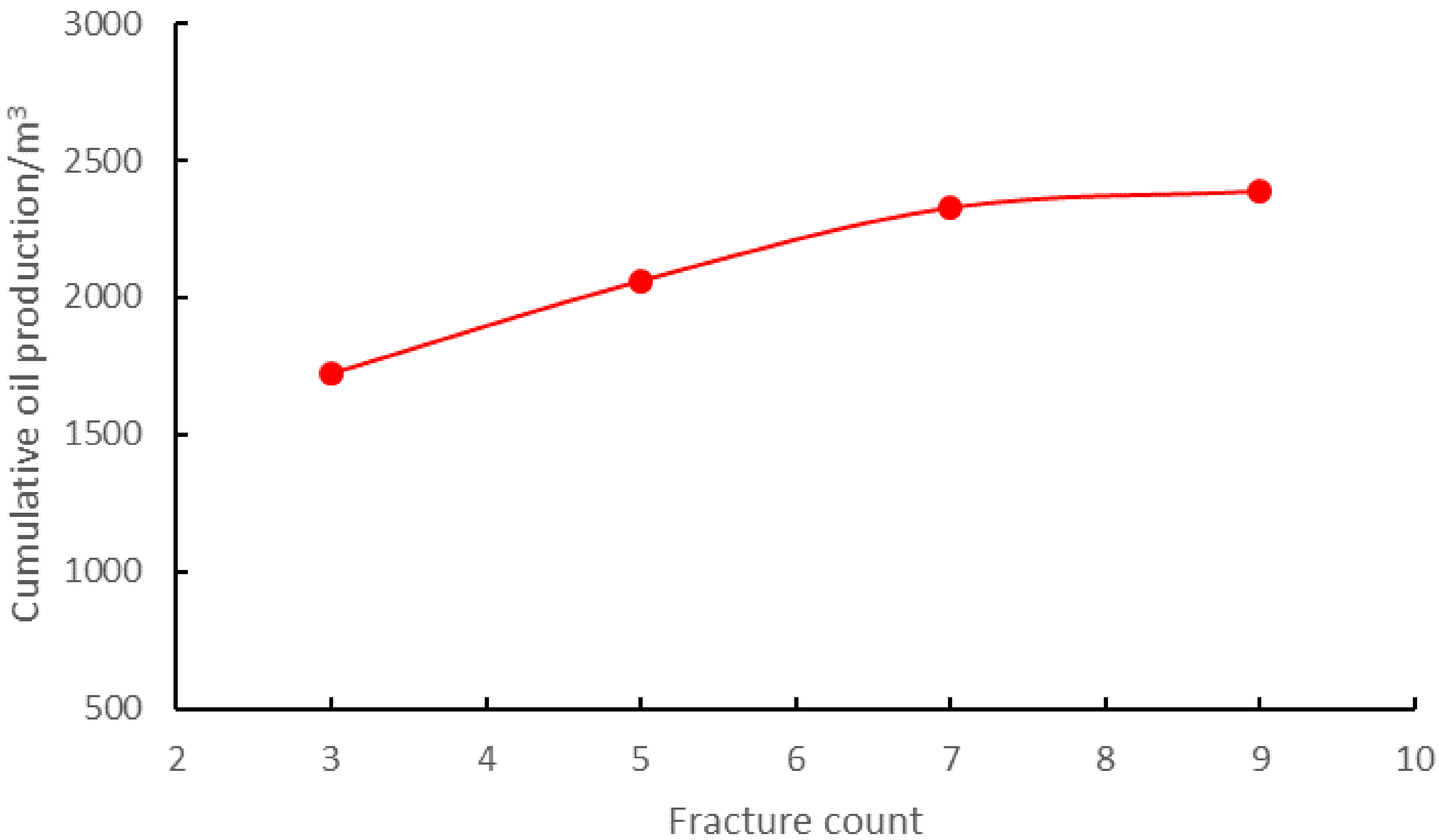

Figure 4. The optimization of fracture count.

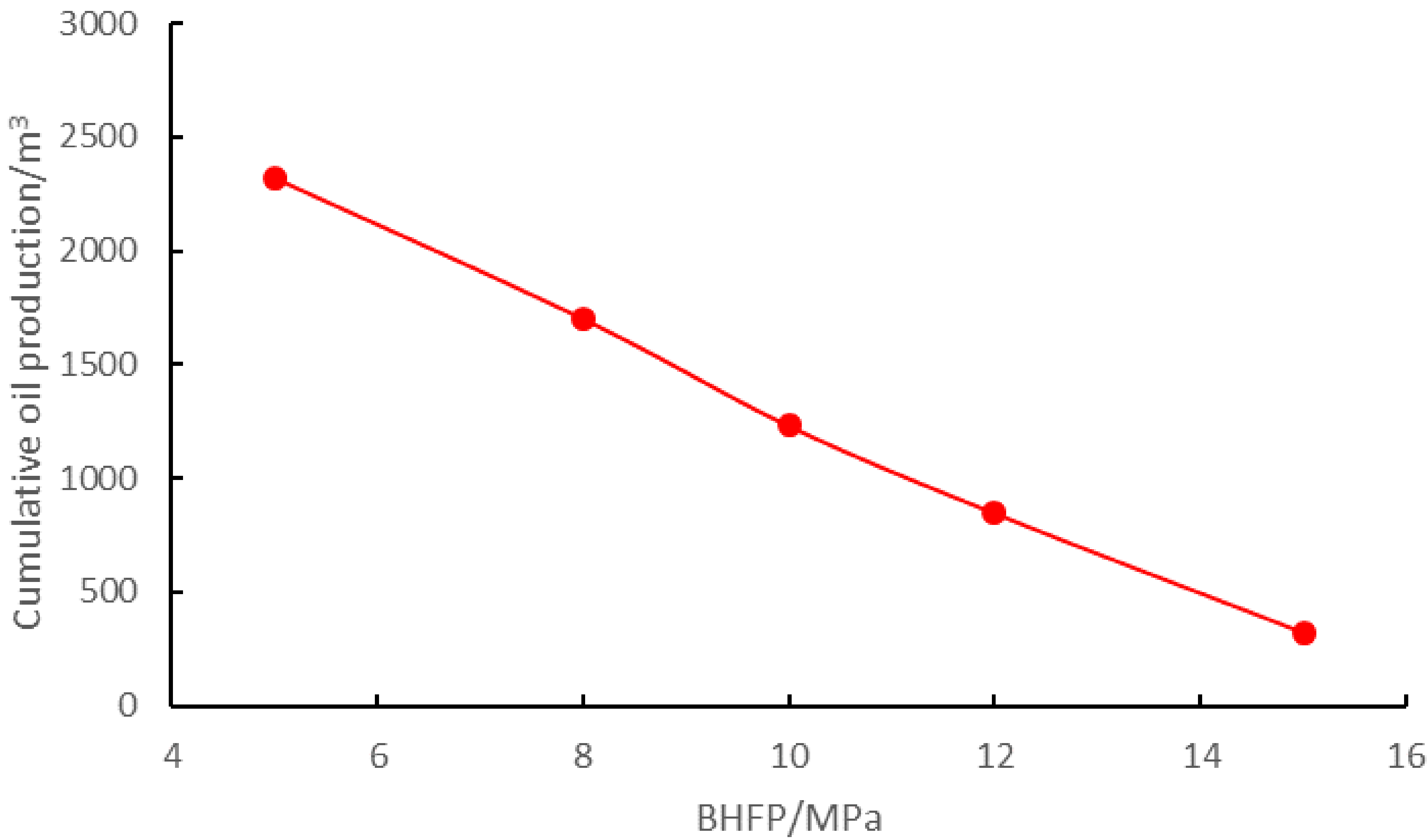

Figure 5. The optimization of well bottom hole flowing pressure.

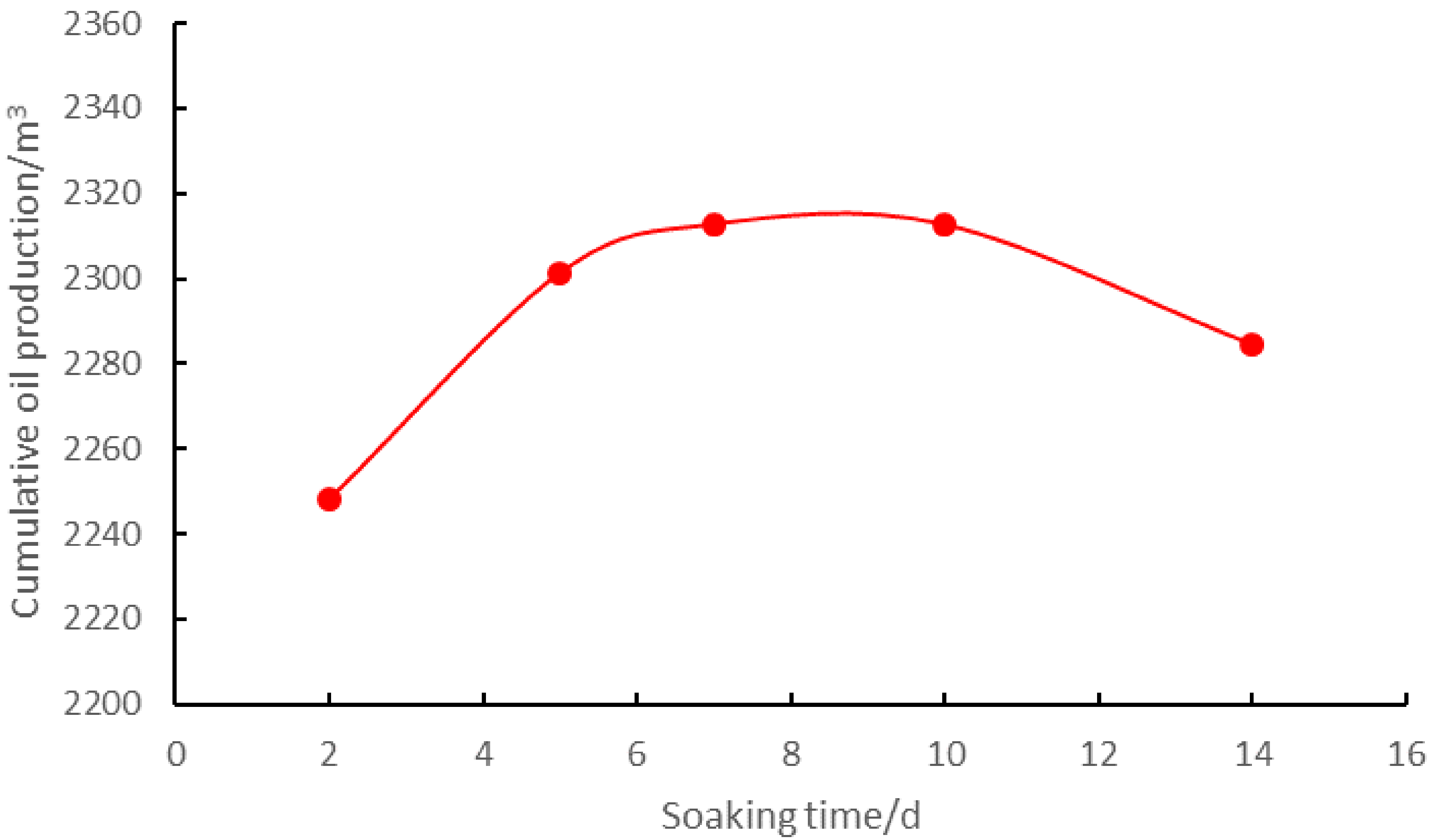

Figure 6. The optimization of soak time.

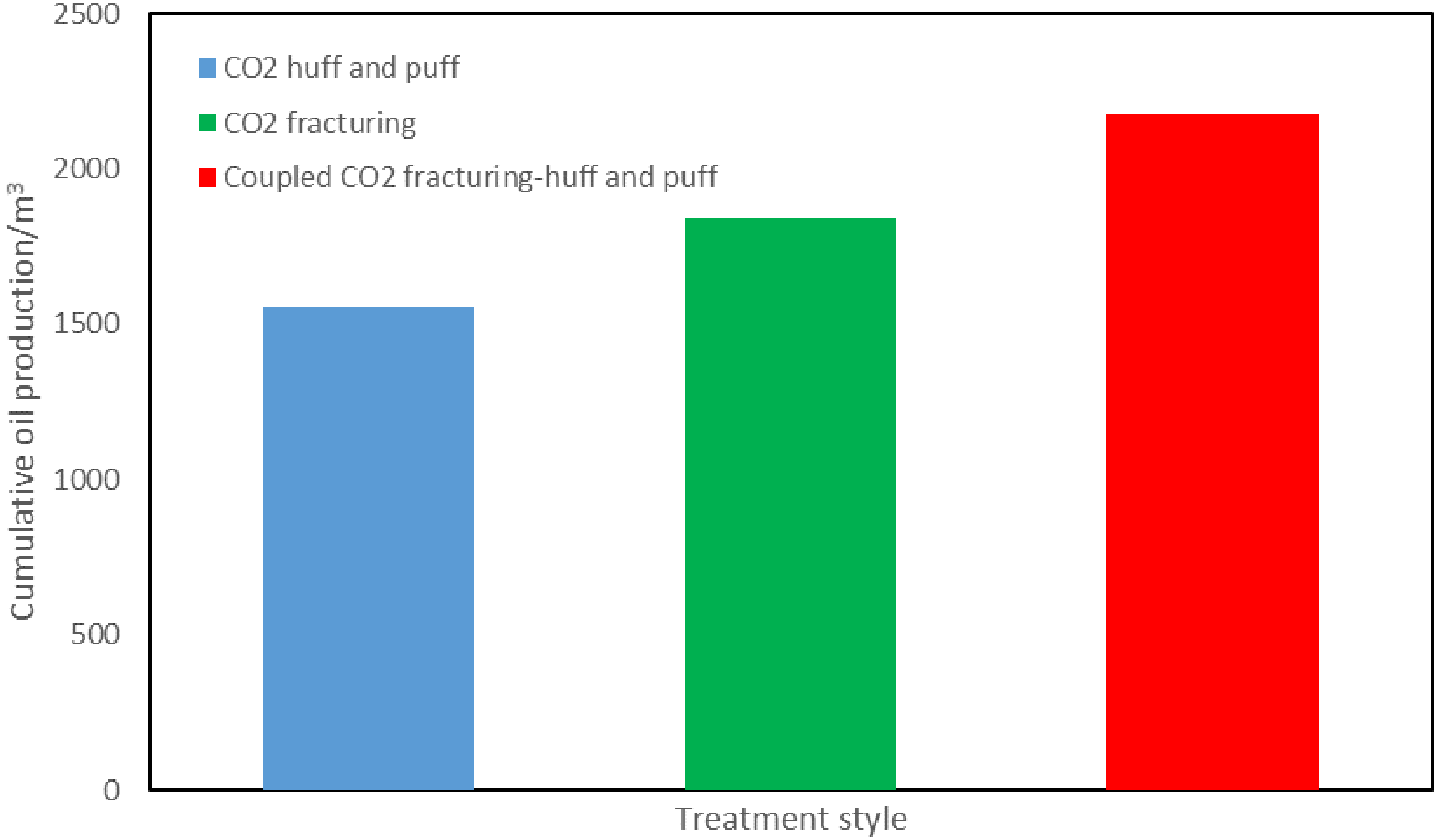

Figure 7. Simulation results comparison of three stimulation methods.

Parameter	Value	Parameter	Value
Porosity/%	11	Gross thickness/m	30
Permeability in X,Y direction/ mD	1×10^{-3}	Permeability in Z direction/ mD	0.01
Depth/m	2350	Temperature/℃	95
Pressure/MPa	24	Oil saturation/%	71

Table 1. Input parameter values of the model.

Parameter	Value
Formation oil viscosity（mPa•s）	2.35
Volume coefficient	1.1599
Compression coefficient (1/MPa)	0.001349
Gas oil ratio of single degassing (m^3/m^3)	38.52
Crude oil density of formation (g/cm^3)	0.7821
Relative density of natural gas	0.75

Table 2. High pressure physical property parameters of oil phase and gas phase.

Factor	Fracture conductivity/(μm^2·cm)	Fracture half-length/m	Fracture count	Soaking time/d	BHFP/MPa
Level 1	20	90	5	2	5
Level 2	25	120	7	5	8
Level 3	30	150	9	7	10

Table 3. The factors and levels of orthogonal test table.

Factor	Fracture conductivity/(μm^2·cm)	Fracture half-length/m	Fracture count	BHFP/MPa	Soaking time/d	Cumulative Oil production/
NO.1	20	90	5	5	2	2060
NO.2	20	120	7	8	5	1580
NO.3	20	150	9	10	7	1230
NO.4	25	90	5	8	5	1500
NO.5	25	120	7	10	7	1200
NO.6	25	150	9	5	2	2380
NO.7	30	90	7	5	7	2310
NO.8	30	120	9	8	2	1690
NO.9	30	150	5	10	5	1150
NO.10	20	90	9	10	5	1220
NO.10	20	120	5	5	7	2070
NO.12	20	150	7	8	2	1590
NO.13	25	90	7	10	2	1220
NO.14	25	120	9	5	5	2370
NO.15	25	150	5	8	7	1510
NO.16	30	90	9	8	7	1680
NO.17	30	150	5	10	2	1150
NO.18	30	120	7	5	5	2320
Range	91.67	31.67	188.33	1056.67	23.33	

Table 4. The orthogonal analysis design and simulation results.