Experimental Modeling of Gas Channeling for Water-alternating-gas flooding in High-temperature and High-pressure Reservoirs

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Abstract

The objective of this study was to investigate gas channeling behavior and its governing factors during water-alternating-gas (WAG) flooding in high-temperature and high-pressure reservoirs. According to the geological characteristics and development conditions of the target carbonate reservoir, various core models were fabricated and the relevant experimental method was designed based on the similarity criterion of physical simulation. A series of experiments were performed to discussed the production performance of WAG flooding, and the effect of core heterogeneity and injection rate on oil displacement efficiency was investigated. Experimental results showed that WAG flooding presented great potential of enhanced oil recovery and good effect on delaying water and gas production. The severer the core heterogeneity, the smaller the fluctuation range and the less the fluctuation frequency of water cut and gas-oil ratio. The effect of WAG flooding on water and gas production control became worse with an increase in core heterogeneity. The injection rate presented less significant effect on oil recovery compared to core heterogeneity. Water and gas breakthrough occurred earlier at a higher injection rate. This experimental study could provide guiding suggestions for reasonable implementation of WAG flooding in the oilfield.

Keywords: WAG flooding; gas channeling; enhanced oil recovery; high-temperature and-high pressure reservoir; physical simulation

1. Introduction

As a non-renewable energy, petroleum plays an increasingly important role in industry[1]. As most of the oil fields have entered the later stage of production, the water cut has increased greatly and the oil production has decreased sharply. Unfortunately, new fields are becoming harder to explore and harder to exploit. In addition, the development and utilization of new alternative energy are in the exploration stage. Therefore, enhanced Oil Recovery (EOR) is still a leading technology for the high-efficiency exploitation of the

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oilfield[2]. Among many EOR technologies, CO_2 flooding has become increasingly popular due to the unique advantages of CO_2 and crude oil with the low minimum miscible pressure (MMP) and its ability of being soluble in crude oil and reducing viscosity. In addition, CO_2 is a greenhouse gas. Injecting it into reservoirs can not only realize long-term underground storage of CO_2 and reduce the greenhouse effect, but also improve oil recovery. However, in the process of oil-displacement, there are also many problems[3-6]. For example, in the middle and late stage of displacement, gas channeling may occur. When gas channeling occurs, gas production rises sharply, and the amount of oil produced is very small. Hence, in recent years WAG flooding has been studied in laboratories and oilfields because of its ability to delay water and gas channeling. Heterogeneity is a universal characteristic of reservoirs. Reservoir heterogeneity is usually characterized by permeability ratio[7]. The existing high permeability layers, artificial or natural fractures, can make the formation more heterogeneous to some extent. Heterogeneity is a sensitive factor affecting oil recovery. In this study, a series of experiments were performed to discussed the production performance of WAG flooding, and the effect of core heterogeneity and injection rate on oil displacement efficiency was investigated.

2. Experimental section

2.1 Preparation of core samples

The cores used in this research were artificial carbonate core models with a sized of 4.5x4.5X30 cm, which have been widely applied in laboratory displacement experiments. Three layered heterogeneous cores with different heterogeneities were employed. As show in **Fig.1**, each core had two layers, the low permeability layer (LPL) and high permeability layer (HPL) [8-9]. Permeability contrast (PC), defined as the permeability ratio of the HPL and LPL, was chosen as the index to represent the heterogeneity of cores. The core permeability ratio V_K is 5, 10 and 15 respectively. In addition, four cores with a permeability difference of 5 are used to study the effect of injection rate on oil recovery.

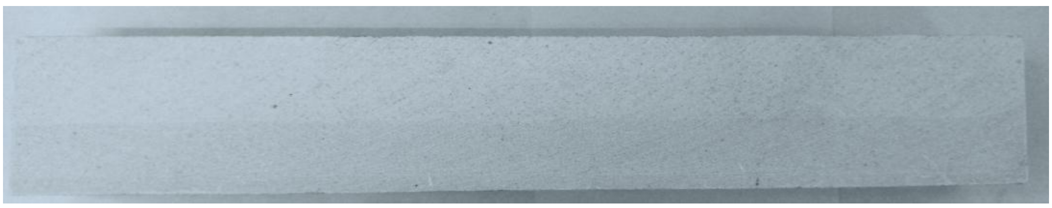

Fig.1 Core samples (Size=4.5cm×4 .5cm×30 cm.)

2.2 Experimental fluid

The water used in the experiments was prepared according to the salinity of the water in the target reservoir. The salinity of simulated water is 265,662 mg/l. The oil used in the experiments was a mixing of the dead oil obtained from target oilfield and gas (CO_2:N_2=10:1) to simulate its experimental viscosity and density according to the criterion of pressure similarity and fluid parameter equivalent. The oil viscosity was 1.079 mPa·s under 84℃

temperature condition and the density was 0.847 g/cm3. Meanwhile, Injected gas is composed of CO_2 and N_2 and the ratio of both is 10:1. The compositional analysis of the dead oil by gas chromatography is presented in **Table 1**.

Table 1. Component of dead oil

Component	Wt%	Component	Wt%
C_3H_8	0.41	FC_{11}	4.71
IC_4	0.24	FC_{12}	4.26
NC_4	0.86	FC_{13}	4.44
IC_5	0.7	FC_{14}	3.61
NC_5	1.33	FC_{15}	3.39
FC_6	3.1	FC_{16}	2.72
FC_7	6.17	FC_{17}	2.28
FC_8	8.06	FC_{18}	2.47
FC_9	6.66	FC_{19}	2.2
FC_{10}	5.45	C_{20+}	36.91

2.3 Experimental setup and procedures

2.3.1 Experimental setup

Fig. 2 shows the details of the experimental setup used for WAG flooding in this study.

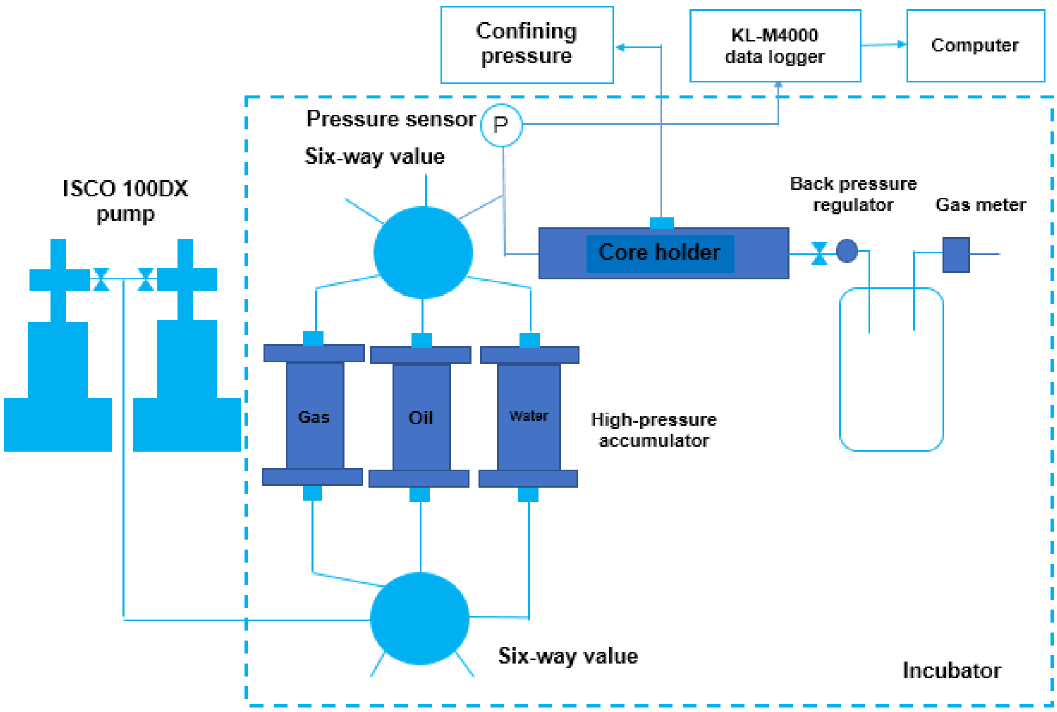

Fig. 2. Diagram of WAG flooding experimental setup

The flow chart of the experimental setup was composed of a power driving system, a core holder and a data acquisition system. An ISCO 100DX cylinder pump provided non-stop power for injecting gas/water stored in high-pressure accumulators. The core holder, high-pressure accumulator and back-pressure regulator were placed inside an oven at a temperature of 84℃. Core of saturated oil under confined water conditions was located in the core holder covered by a rubber sleeve. A confining pressure was applied to the core gripper through the rubber sleeve, which enabled the core to be strongly coated and enabled fluid to pass through the cross-sectional area of the core in the horizontal direction, preventing fluid flow around the core holder. The back-pressure regulator guaranteed the stability of the test pressure, and compressed water was used to maintain the back pressure. All of the pressures were tested and recorded by pressure sensors connected to the facility. During displacement, the tube is used to measure the volume of oil and water produced, and the volume of gas produced is measured by a gas meter.

Using the above facilities, WAG tests were performed under varying experimental conditions and injection strategies to investigate the following parameters: 1) permeability ratio (Vk=5,10,15); 2) injected rate (v=0.1ml/min, 0.2ml/min, 0.3ml/min, 0.4ml/min). The influences of such factors on WAG injection EOR processes in target reservoirs were experimentally researched.

2.3.2 Experimental procedures

An artificial carbonate core whose dimensions, permeability ratio, injected rate and back-pressure are given in **Table 2** was wrapped with a mixture of epoxy resin and curing agent.

Table 2. Core properties and experimental conditions of WAG flooding.

Core number	Physical model size	Permeability ratio	Injected rate (ml/min)	Back-pressure (MPa)
#1	4.5x4.5x30cm	5	0.2	25
#2		10	0.2	25
#3		15	0.2	25
$1		5	0.1	25
$2		5	0.3	25
$3		5	0.4	25

For core flooding experiments, the sequence of experiments was as follows.

①Artificial carbonate cores coated with epoxy resin and curing agent were put into the core holder and then confining pressure was added. ②The core was vacuumed for 4-6 hours and saturated with formation water to calculate the permeability of water phase. ③Calculate oil saturation after the core was saturated with crude oil. ④The aging stage of the oil, which lasted 24 hours, was designed to be consistent with the form of crude oil that has been stored in the actual formation for countless years. ⑤According to experimental requirements, different permeability ratio and injection rates were set. ⑥In the way of first gas injection and then water injection cycle alternating injection, the gas-water volume ratio was 1:1. ⑦The experiment was terminated when the producing gas-oil ratio reached 3000mL/mL.

3. Results and discussion

3.1 Production performance during WAG flooding

Fig. 3 shows the production performance of core #1 during WAG displacement, which can be divided into four stages: no liquid stage, evolved gas and waterless production stage, oil-gas-water co-production stage and gas channeling stage. For the other cores, the experiments under different injected rate or rock heterogeneity conditions, exhibited the similar characteristics with the #1. As illustrated in **Fig.3**, at no liquid stage, the injected fluid mainly plays the role of replenishing formation energy and reducing the viscosity of crude oil. In addition, there is mass transfer between gas and crude oil during the process to produce near-miscible or miscible effects. The crude oil is produced mainly at evolved gas and waterless production stage and oil-gas-water co-production stage. However, the oil recovery basically does not increase when gas channeling occurs.

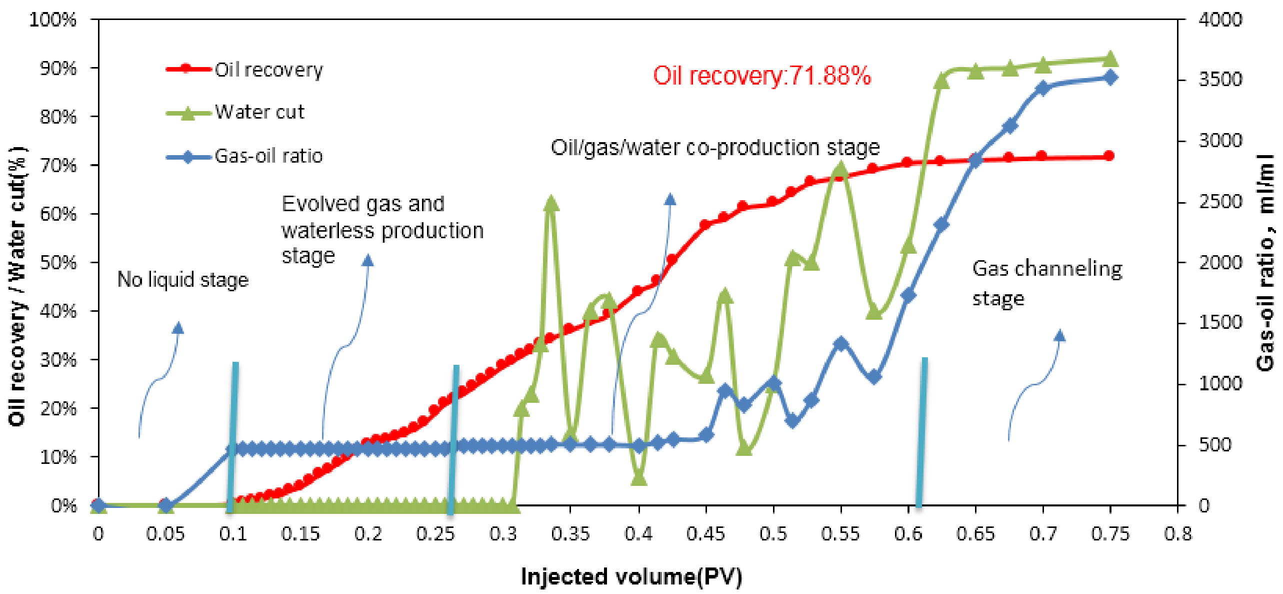

Fig.3 Producing gas-oil ratio, water cut and oil recovery curve of WAG in heterogeneous core sample (#1)

3.2 Effect of permeability heterogeneity

The effects of different permeability, temperature and pressure on the channeling of injected fluid in porous media. Through investigation, the following conclusions are drawn: for cores with a great difference in permeability between the low permeability layer and the high permeability layer, injection fluid tends to be in the high permeability layer. In other words, the high permeability layer is easier to form channeling channels than the low permeability layer. In addition, the higher the permeability of the reservoir is, the more obvious the phenomenon of gas overlap will be, and the more serious the gas/water channeling will be.

3.2.1 Effect of heterogeneity on oil recovery

WAG injection tests were performed in cores with different heterogeneities to determine the influence of heterogeneity on oil recovery. Permeability ratio was chosen as the index of heterogeneity. It was designed to be 5, 10, and 15 according to the reservoir heterogeneities of the target oilfield. A permeability ratio of 5 represents a weak heterogeneity, while 10 permeability ratio represents a moderate heterogeneity, and 15 permeability ratio simulates strong heterogeneity. As explained in the experimental section, WAG displacement experiment was carried out under the same conditions except for different permeability ratio, and the experimental results were shown in **Fig. 4-6**.

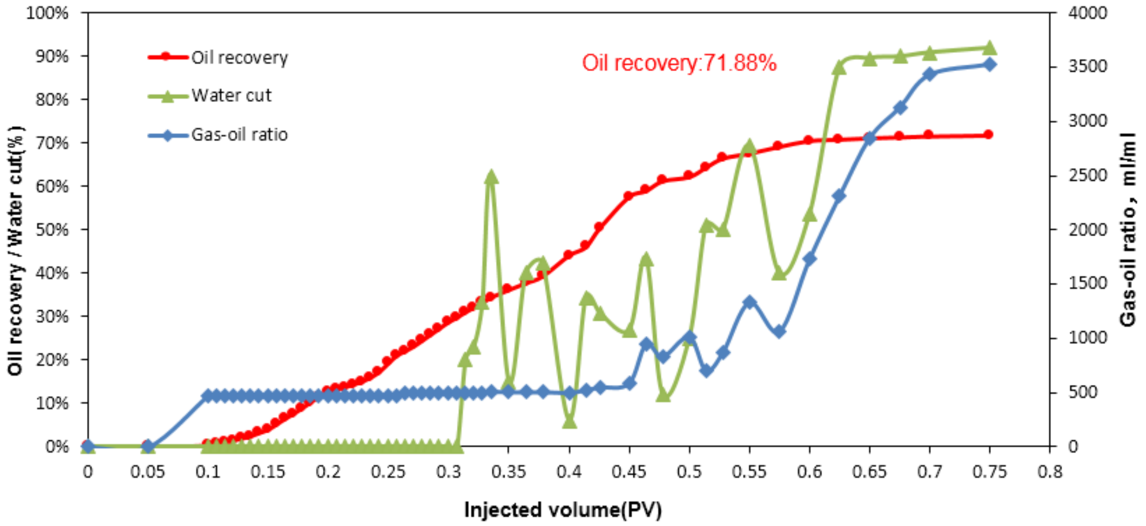

Fig.4 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample (#1)

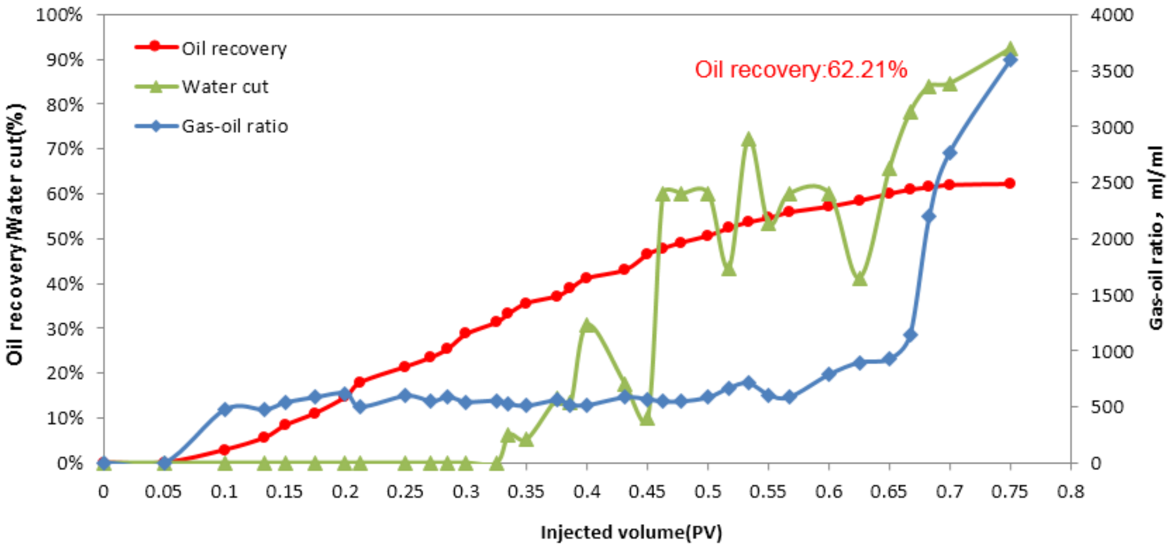

Fig.5 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample (#2)

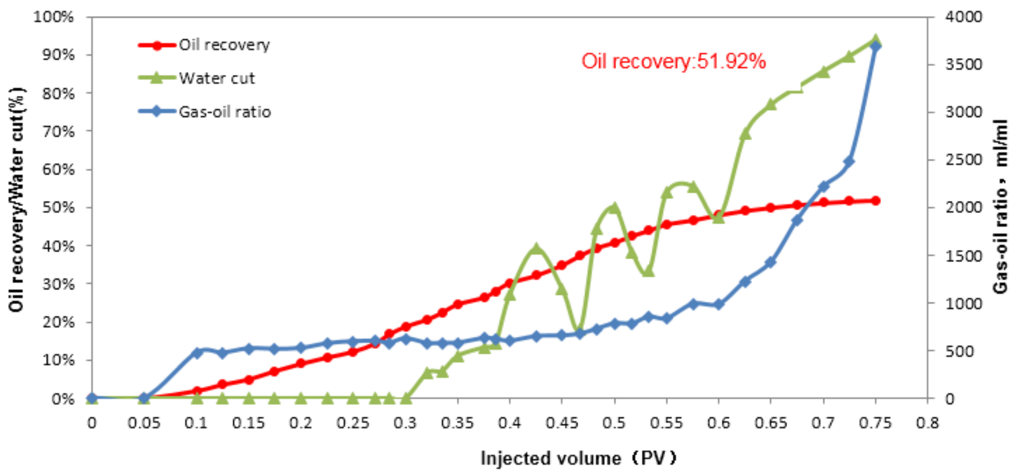

Fig.6 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample (#3)

As shown in the **Fig.4-6**, other conditions being unchanged, oil recovery with a permeability ratio of 5 was 71.80%, a permeability ratio of 10 was 62.21%, and a permeability ratio of 15 was 51.92%. In terms of oil recovery, the ultimate recovery decreased with the rise of permeability ratio. In other words, with the increase of core heterogeneity, the displacement effect of WAG became worse. This indicates that the injected fluid flowed preferentially into the highly permeable layer and bypassed the low permeable layer, resulting in reduced sweep efficiency and affecting ultimate recovery.

As far as water cut and gas-oil ratio were concerned, no matter the core is weak heterogeneity, moderate heterogeneity, or even strong heterogeneity, water cut and gas-oil ratio show roughly the same trend with the increase of injection volume, and they all rise in a wavy zigzag manner during WAG displacement. However, the higher the heterogeneity, the smaller the fluctuation range of water cut and gas-oil ratio, and the less the fluctuation frequency. That can be explained that the effect of WAG displacement on controlling water and adding oil became worse as core heterogeneity increases. In the later stage of displacement, the water content and gas-oil ratio significantly increased and no longer fluctuated, indicating the formation of gas channeling, the recovery curve tended to be stable and the alternating gas-water flooding gradually failed.

3.2.2 Effect of heterogeneity on the timing of gas breakthrough

During alternating gas/water injection, the increase of water injection pressure was obvious, while the increase rate of gas injection pressure was low, and the displacement pressure difference presented the characteristics of stage supercharging. However, the injection pressure also showed an upward trend after several cycles. It was caused by the large amount of air/water interface, the rapid increase of capillary resistance, and the gradual rise of gas injection pressure. Therefore, WAG injection can be used as an effective method to control gas channeling. However, with the increase of permeability ratio, the effect of WAG flooding to control gas channeling began to decline. **Table 3** showed the gas breakthrough time, gas channeling time and their oil recovery under different permeability ratio.

Table 3. Oil recovery at different displacement times

Permeability ratio	Gas breakthrough timing (PV)	Oil recovery at gas breakthrough timing	Gas channeling timing (PV)	Oil recovery at gas channeling timing
5	0.264PV	22.19%	0.6PV	70.63%
10	0.175PV	11.04%	0.667PV	60.91%
15	0.225PV	10.68%	0.65PV	50%

When the permeability ratio became larger and larger, that is, core heterogeneity became stronger and stronger, the gas breakthrough time tended to advance. Due to the limitation of the number of experimental groups, there was no obvious regularity. However, according to the parameter of oil recovery at gas breakthrough, the oil recovery went from 22.19% to 10.68%, This phenomenon is relatively intuitive, that is, with the enhancement of heterogeneity, the oil recovery at the gas breakthrough timing gradually dropped off. As can be seen from **Table 3**, cores with permeability ratio of 5 and 10 had 10.15% difference in recovery at gas breakthrough, while cores with permeability ratio of 10 and 15 had only 0.36% difference in recovery. It can be inferred that the sensitive limit of the recovery at the gas breakthrough moment to the permeability ratio may exist, of course, it needs to be further studied. In addition, no obvious regularity was found at the time of gas channeling.

3.2.3 Effect of heterogeneity on water cut and gas-oil ratio

Fig.7 illustrated the production performance of water cut with oil recovery in different ratio. With the increase of oil recovery, the water cut also presented an upward trend, and when the recovery reached a certain level, the water cut rised sharply. The water cut curve showed a trend of shifting to the right and became more concave with the increase of the permeability ratio. To a certain extent, it can also reflect that the water control effect of WAG flooding gradually weakened with the enhancement of heterogeneity.

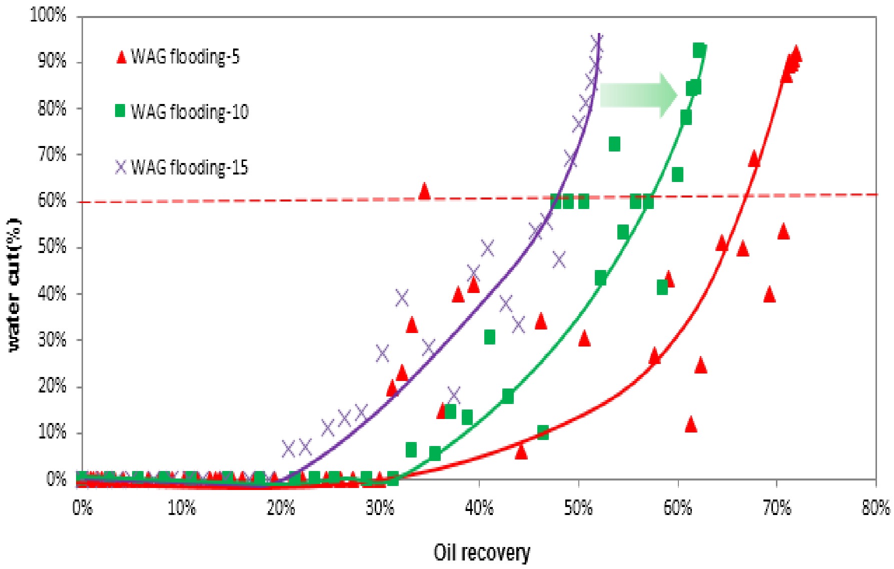

Fig.7 Production characteristics of water cut with oil recovery

Fig. 8 depicted the production performance of gas-oil ratio with oil recovery in diverse heterogeneity. The rising curve of gas-oil ratio was generally consistent with that of water cut in **Fig.7.** With the increase of heterogeneity, the upward curve of gas-oil ratio shifted to the right and the ability to delay gas channeling decreased gradually.

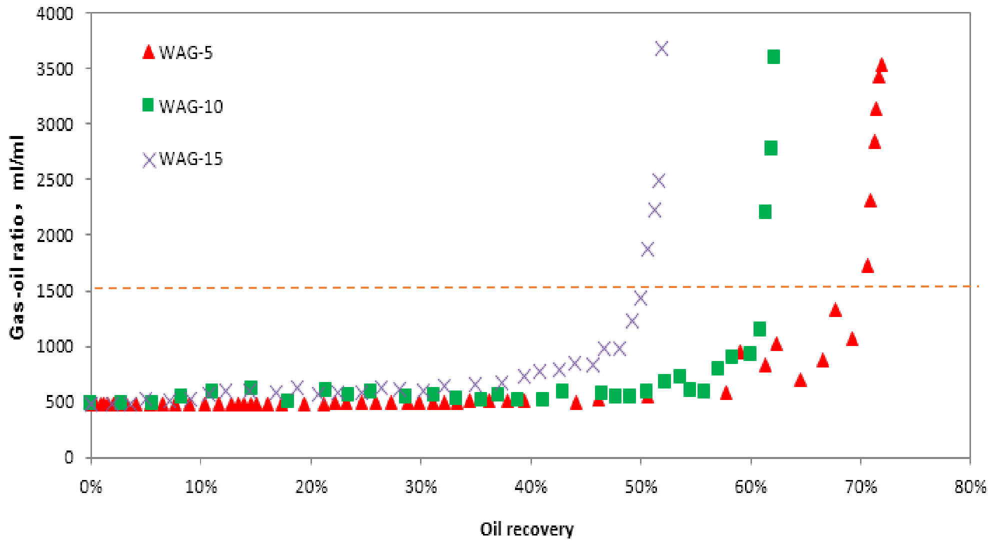

Fig.8 Production characteristics of gas-oil ratio with oil recovery

According to the comprehensive analysis of the results in Fig. 7 and Fig. 8, if the medium water cut was 60%, the recovery of weak heterogeneous, moderate heterogeneous and strong heterogeneous cores was 67.63%, 58.41% and 48.18% respectively. Using the same method, with the gas-oil ratio of 1500 as the boundary, the oil recovery was respectively 70.63%, 60.91% and 50% with the core heterogeneity from weak to strong. From the change of water cut and gas-oil ratio, it can be inferred that the effect of controlling water and delaying gas channeling of WAG flooding decreased with the increase of heterogeneity.

3.3 Effect of injection rate

The displacement effects of four different injection rates in heterogeneous cores were studied. The production characteristics of oil, gas and water were shown in **Fig. 9-12**.

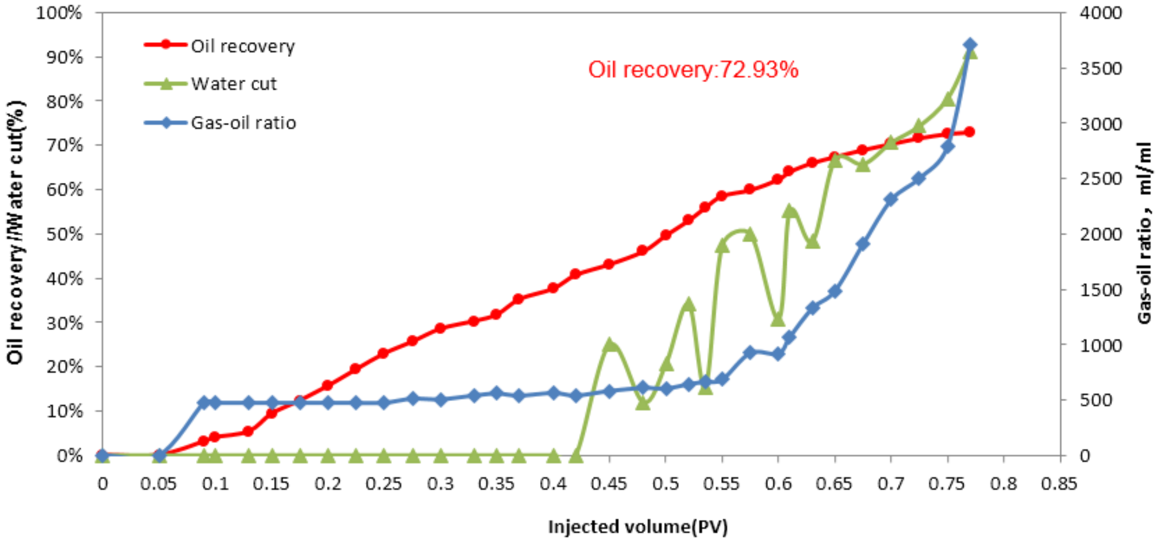

Fig.9 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample ($1)

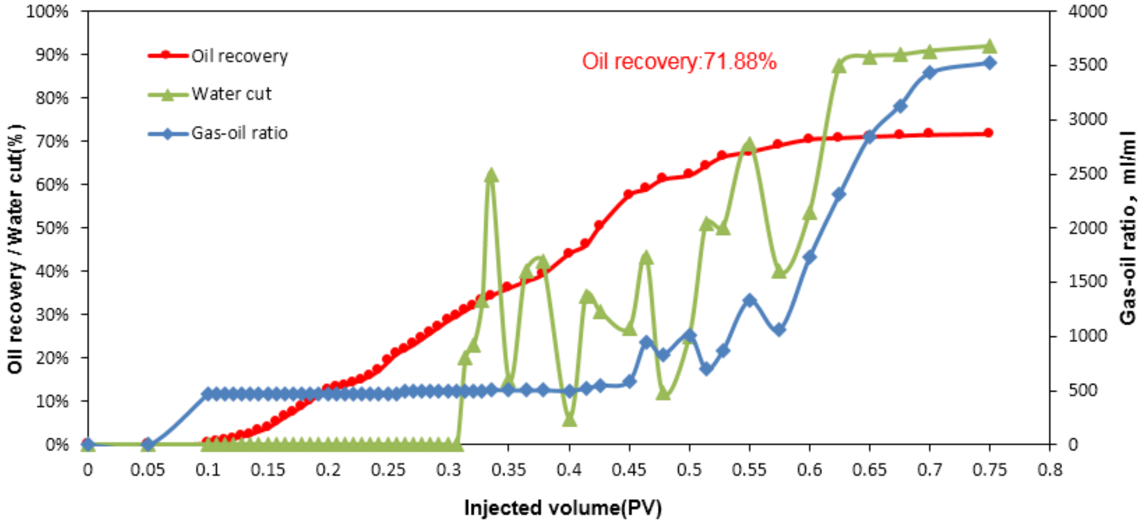

Fig.10 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample (#1)

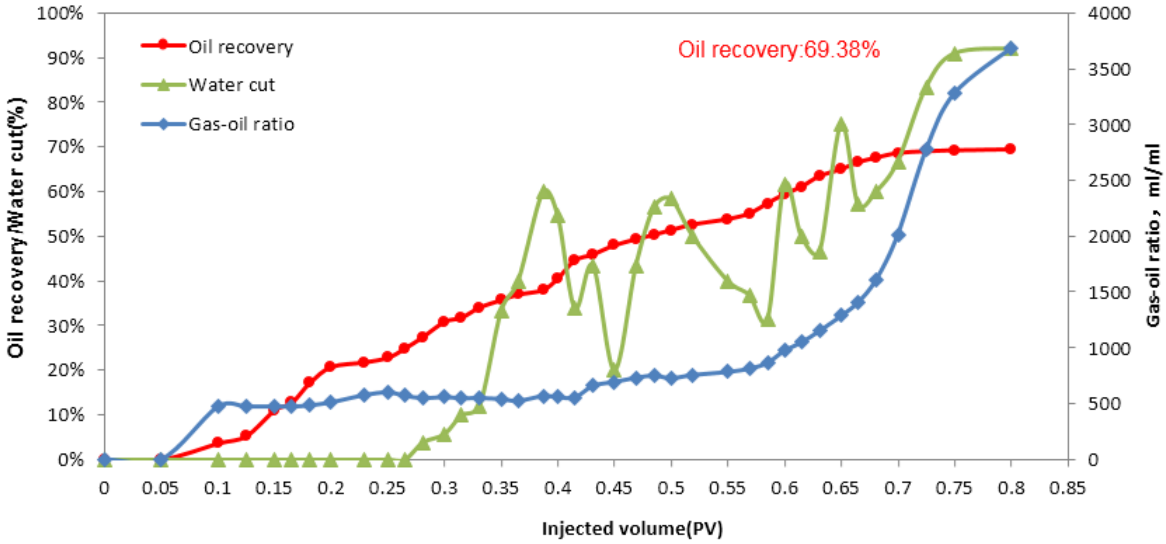

Fig.11 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample ($2)

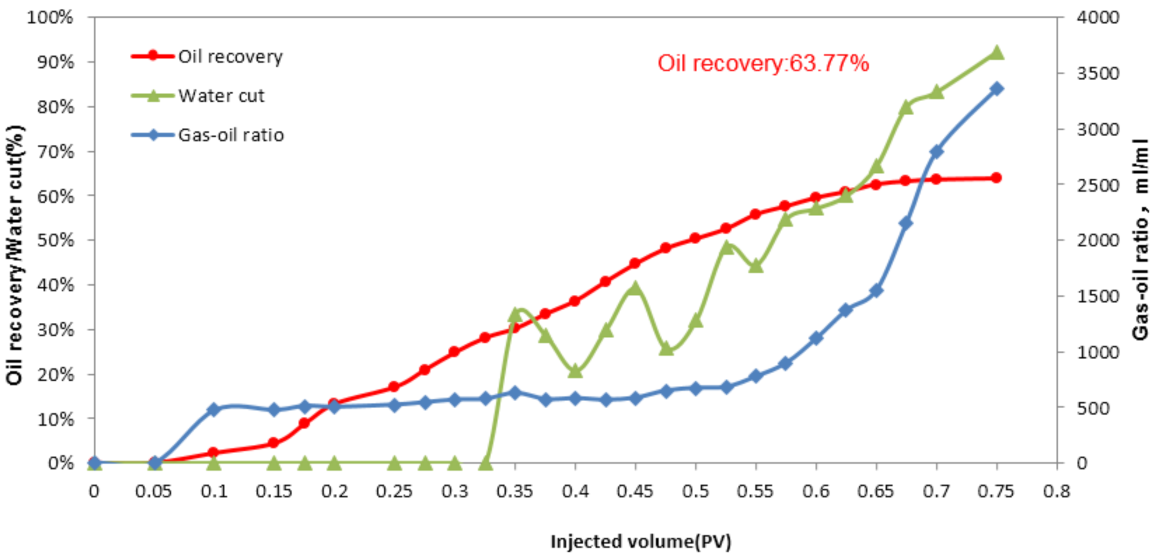

Fig.12 Producing gas-oil ratio, water cut and oil recovery curve of WAG flooding in heterogeneous core sample ($3)

In the range of experimental injection rate, with the increase of displacement rate, the oil recovery decreased gradually. As can be seen from the Fig.9-12, when the injected rate is 0.1ml/min, the oil recovery is the highest, reaching 72,93%. However, the displacement time is twice that of 0.2ml/min. According to the actual situation on the site and the overall economic benefits, the experiment of 0.1ml/min cannot reach the maximum NPV. In the gas production stage, the growth rate of recovery was the slowest when the injection rate was 0.4 ml/min, and the fluctuation range of gas-oil ratio and water cut was the most obvious when the injection rate was 0.2 ml/min, and the increase of recovery was the largest at this time.

Table 4 depicted the oil recovery at different displacement times. The increase of injection speed led to the advance of gas breakthrough time, and the recovery efficiency decreased at both gas breakthrough time and gas channeling time.

Table 4 Oil recovery at different displacement times

Injected rate	Gas breakthrough timing (PV)	Oil recovery at gas breakthrough timing	Gas channeling timing (PV)	Oil recovery at gas channeling timing
0.1 ml/min	0.3PV	28.53%	0.7PV	70.27%
0.2 ml/min	0.264PV	22.19%	0.6PV	70.63%
0.3 ml/min	0.181PV	17.11%	0.665PV	66.49%
0.4 ml/min	0.175PV	8.83%	0.65PV	62.47%

The relationship between water cut and oil recovery was shown in **Fig.13**. The water cut curve tended to shift to the right with the increase of injection rate, but for a single water cut curve, the distribution of data points was complex, and no obvious rule was found.

Compared with **Fig.13**, the gas-oil ratio changed more obviously with the increase of oil recovery in **Fig.14**. As can be seen from the Fig.14, the gas-oil ratio with injection rate of 0.2ml/min rised the slowest.

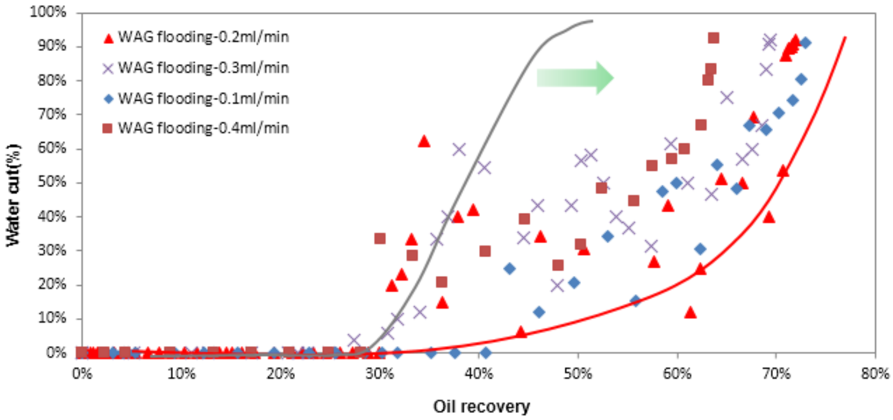

Fig.13 Production characteristics of water cut with oil recovery

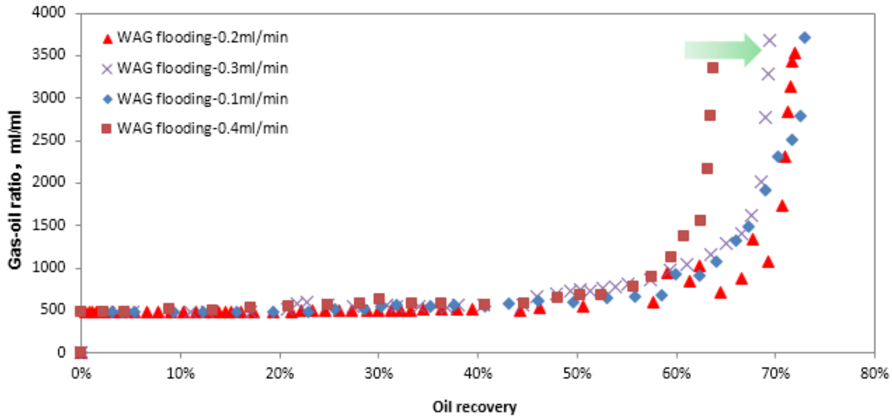

Fig.14 Production characteristics of gas-oil ratio with oil recovery

Compared with the permeability ratio, the injection rate had little effect on the ultimate oil recovery, mainly affecting the WAG flooding effect time. The faster the injection rate was, the earlier the effect time would be. Conversely, the slower the injection rate, the later the effect time. For different reservoirs, there was an optimal injection rate. If the injection rate was too fast, the formation of gas or water channeling would be intensified, and the displacement effect of WAG would be worse.

4. Conclusions

1) WAG flooding achieved an oil recovery of 71.88%, 62.21% and 51.92% in the core samples with a permeability ratio of 5, 10 and 15, respectively. With the increase of core heterogeneity, oil recovery decreased remarkably.

2) The severer the core heterogeneity, the smaller the fluctuation range and the less the fluctuation frequency of water cut and gas-oil ratio. The effect of WAG flooding on water and gas production control became worse with an increase in core heterogeneity. In the later

stage of displacement, the water cut and gas-oil ratio significantly increased and no longer fluctuated, and the recovery tended to be stable.

3) The injection rate presented less significant effect on oil recovery compared to core heterogeneity. Water and gas breakthrough occurred earlier at a higher injection rate.

Acknowledgments

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