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Experimental study on the mechanism of enhanced oil recovery by multi-thermal fluid in offshore heavy oil

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ABSTRACT

The multi-thermal fluid process is a new technology that was generated for the development of offshore heavy oil. It has achieved remarkable results in the development of Bohai Oilfield. However, the mechanism of enhanced oil recovery still requires further discussion. Based on the physical similarity criterion, a physical simulation experimental device was independently designed to execute laboratory experiments on different thermal recovery methods (hot water, steam, and multi-thermal fluid), after which the contents of the four components of developed heavy oil were measured and analyzed. The results of the physical simulation experiments indicated that: (1) Thermal viscosity reduction and thermal expansion are the principle mechanisms of hot water flooding; (2) Thermal viscosity reduction and steam distillation are the principle mechanisms of steam flooding, which are accompanied by a certain degree of aquathermal cracking reaction between heavy oil and steam; and (3) thermal viscosity reduction and aquathermal cracking reaction are the principle mechanisms of multi-thermal fluid flooding. Due to the synergistic effect of nitrogen and carbon dioxide, the effect of viscosity reduction by the dissolution effect and gas-water hybrid drive must also be considered. The analysis results of the four components of developed heavy oil by the different thermal recovery methods indicated that the multi-thermal fluid changed the balance of the aromatics-asphaltene-resin regime and strengthened the development degree of the asphaltene component in heavy oil, thereby improving oil recovery through the thermal/physical/chemical mechanism.

1. Introduction

Offshore oil and gas fields in China are mainly distributed in Bohai Bay, the East China Sea, the west and east of the South China Sea [1]. The Bohai Oilfield has approximately 2.3 billion tons of heavy oil resources [2]. According to Sheikholeslami et al. [3–5], the significant amount of offshore heavy oil resources has recently attracted much attention and enhanced oil recovery technologies have played an increasingly important role in industry. Enhanced oil recovery (EOR) technologies mainly include the following six aspects: improved water flooding, chemical flooding, heavy oil thermal recovery, gas flooding, microbial enhanced oil recovery, and physical oil recovery, all of which aim to improve the sweep efficiency and/or displacement efficiency [6]. In addition, field tests have proved the effectiveness of thermal technologies in petroleum industry [7–10]. Among those technologies, steam, CO_2, N_2, flue gas, composite gas, and multi-thermal fluids are widely used as recovery agents. Undoubtedly, the mechanisms of these thermal technologies are vital to the development of offshore heavy oil. As a result, the mechanisms of technologies with steam, CO_2, N_2, flue gas, and composite gas have been widely examined. Unfortunately, the mechanism of multi-thermal fluid recovery has never been easy due to the presence of nitrogen and carbon dioxide.

As we know, steam is widely used in heavy oil recovery. Willman et al. [11] indicated that thermal expansion of oil, viscosity reduction and steam distillation was the principle mechanisms which were responsible for the additional oil by steam injection. Harding et al. [12] suggested that the presence of nitrogen and carbon dioxide in steam resulted in a slight improvement in the overall recovery and a marked improvement in the rate of oil production. Hong et al. [13] indicated that non-condensable gas injection with steam accelerated oil recovery as a result of the increased volume of displacing gas phase and the lowered oil

Abbreviations: Multi-thermal fluid, multiple components thermal fluid; EOR, enhanced oil recovery; SARA, saturates, aromatics, resin, and asphaltene (i.e., the four components); ISCO pump, pump manufactured by the ISCO industries; PV, pore volume; S+A, saturates and aromatics; MMP, minimum miscible pressure; HDNS, horizontal well, viscosity reducer, nitrogen and steam flooding.

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viscosity following the gas dissolution in oil. Nasr et al. [14] indicated that the addition of flue gas to the steam substantially improved both rate and ultimate recovery of bitumen as compared to that obtained by steam alone.

The development of the thermal recovery technique has increased investigations on the feasibility and mechanism of the immiscible CO_2 displacement application process. Based on the experimental results of the CO_2 displacement process in the West Sak oil field, Hatzignatiou et al. suggested that larger CO_2 slug sizes resulted in higher the oil recovery rates [15]. Rojas et al. [16] asserted that immiscible CO_2 flooding is an important recovery method, particularly for thin, marginal, or poor heavy oil reservoirs based on scaled model experiments. Malik [17] proved the efficiency and applicability of horizontal injection wells to improve the recovery of the CO_2 flooding process. Song et al. [18] developed experimental and numerical techniques to evaluate the performance of CO_2 huff-n-puff processes in the Bakken formation, of which either a higher injection pressure or a lower wellhead pressure generated higher recovery during the CO_2 huff-n-puff process.

In addition, nitrogen has also been used to improve heavy oil recovery. Wang et al. [19], Liu et al. [20], and Fan et al. [21] concluded that the effect of nitrogen dissolution and separation aided not only in changing the composition of heavy oil but also in improving flow behavior of crude oil. Li et al. [22] and Jia [23] suggested that nitrogen exhibited minimal effect on the viscosity of heavy oil, and the viscosity reduction of heavy oil was highly dependent on the effect of high-temperature steam as exhibited by nitrogen-assisted steam experiments.

Many studies have indicated that flue gas significantly influences oil recovery improvements. Liu et al. [24] indicated that mixing the injection of steam with flue gas strengthens the distillation of steam. Fu et al. [25] concluded that flue gas exhibited significantly improved heavy oil recovery based on a sanding model. Zhu et al. [26] suggested that the effect of flue gas-assisted steam process was much better than the steam injection process based on numerical simulation results. Li et al. [27] indicated that the presence of flue gases significantly improved the heating range and the sweep volume of steam. Ma et al. [28] suggested that flue gas flooding can effectively improve heavy oil recovery according to field tests. Johnson [29] demonstrated the economical applicability of flue gas huff-and-puff method to some shallow reservoirs at current (1989) posted oil prices. Srivastava et al. [30] executed one-dimensional linear coreflood tests with Senlac oil-flue gas and evaluated various operating strategies for heavy oil recovery. Dong et al. [31] performed PVT studies and two-dimensional physical model experiment to examine the effects of the flue gas on viscosity reduction and oil swelling.

Raj et al. [32] compared the effectiveness of CO_2, produced gas, and flue gas on the enhancement of Senlac heavy oil recovery, of which the experimental results indicated that the flue gas was the most suitable gas. However, Han [33] and Liu [34] proved the higher recovery suitability of high-temperature composite gas flooding as compared to both steam-CO_2 flooding and steam-nitrogen flooding.

However, most of the previous recovery agents are based on conventional steam injection technology. In recent years, a new multi-thermal fluid was introduced into the development of offshore heavy oil reservoirs, such as Shengli Oilfield [35] and Bohai Oilfield [36]. This fluid is a gas mixture of steam and non-condensable gas, and the main components include steam, nitrogen and carbon dioxide. Most of the current research on the application of this multi-thermal fluid in the development process of heavy oil reservoirs focuses on pilot tests and technological process. In 2009, the Shengli Oilfield in China introduced an EOR project. As Ren [37] reported, a multi-thermal fluid stimulation process was performed in a typical multicycle cyclic steam simulation (CSS) well, namely the GDN5-604 well. According to Yu et al. [38], in 2010, a multi-thermal fluid stimulation process was introduced into the Bohai Offshore Oilfield in China to develop an NB35-2S heavy oil block. In terms of the development mechanisms of the multi-thermal fluid in heavy oil reservoir, most of the current research focuses on the conventional gas mixture of steam and non-condensable gas. Stone et al. [39] performed a series of experiments and found that the steam-CO_2 injection process exhibited a better recovery performance. Metwally et al. [40] discovered that the co-injection of steam and CO_2 tremendously increased oil recovery. Frauenfeld et al. [41] indicated that the co-injection of CO_2 with steam was capable of improving oil recovery. Wang et al. [42] observed that the combination effect of all parts of the horizontal well, viscosity reducer, nitrogen and steam flooding (HDNS) significantly increased the steam sweep volume. Ferguson et al. [43] suggested that steam-propane injection at a 5:100 mass ratio of propane:steam accelerated the start and peak of oil production by 20% and 13%, respectively, as compared to steam alone. Monte-Mor and Trevisan [44] found that the co-injection of steam with flue gas accelerated the initiation of oil production as compared to steam. Mohsenzadeh et al. [45] indicated that flue gas injection simultaneously activated the gas dissolution mechanism and high oil/gas density difference mechanism. Therefore, based on the above observations, we focused on the EOR mechanisms of the multi-thermal fluid for the development of offshore heavy oil reservoirs.

In this paper, a series of experiments and research were conducted on the mechanism of enhanced oil recovery by a multi-thermal fluid in offshore heavy oil. The novelty of this paper lies in three aspects: (1) A physical simulation experimental device was independently designed to execute different thermal recovery experiments, especially for the realization of the multi-thermal fluid; (2) The change of four components, specifically the saturates, aromatics, resin, and asphaltene (SARA) content, was introduced to explain the stimulation mechanism of the multi-thermal fluid; and (3) The mechanisms of different thermal recovery methods (hot water, steam, and the multi-thermal fluid) for the offshore heavy oil were analyzed in detail.

2. Experiments

2.1. Experimental system

To simulate the recovery effect of the different thermal recovery methods (hot water flooding, steam flooding, and multi-thermal fluid flooding) and to examine the EOR mechanism, a physical simulation experiment device was established independently, as presented in Fig. 1. The experimental system mainly includes five parts: a multi-thermal fluid system, a steam system, a hot water system, a constant temperature system, and a data acquisition system. The main experimental devices were employed as follows: a steam generator to provide steam at a certain temperature and at a constant flow rate, a back pressure valve and hand pump to set the needed back pressure, a check valve to prevent gas backflow, an intermediate container to provide the N_2-CO_2 mixture, a six-way valve to separately provide different kinds of injection agents, an ISCO pump to provide deionized water at a constant flow rate, and a sanding model to simulate the porous media.

2.2. Experimental steps

(1) Fabrication of the sanding model: According to the physical properties of the reservoir, 80 mesh glass beads were used to simulate the porous media by pressing the sanding model each time it was filled with 15 g glass beads.

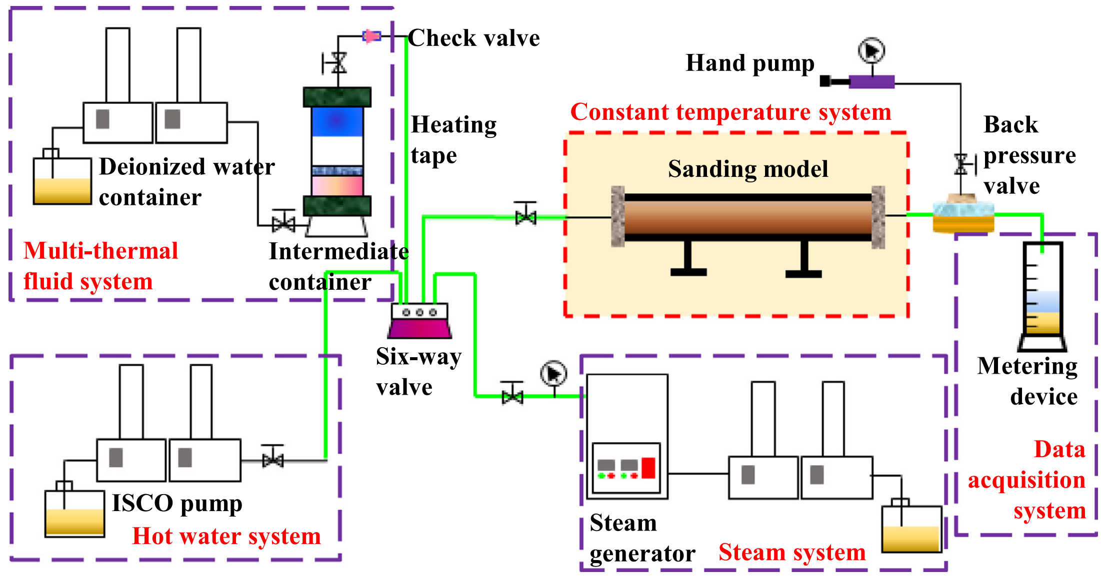

Fig. 1. A schematic diagram of the physical simulation experiment system.

(2) Measurement of the gas phase permeability: The gas flowmeter recorded the nitrogen flow rate and the pressure gauge recorded the corresponding pressure difference. On this basis, the gas phase permeability was obtained using the Darcy formula.
(3) Saturated water was maintained at the formation temperature and allowed to stand for 24 h.
(4) Measurement of the water phase permeability: Deionized water was pumped into the sanding model at a constant speed. At a stable pressure difference, the pressure and flow rate were recorded, and the water phase permeability was calculated.
(5) After the temperature of the constant temperature system was set to the reservoir temperature, the sanding model was placed in the constant temperature system for 12 h.
(6) Determination of the irreducible water saturation: The heavy oil was pumped into the model at the flow rate of 0.5 mL/min. After 3 pore volumes (PV) of heavy oil were pumped into the model, the irreducible water saturation was calculated.
(7) Measurement of the oil phase permeability: The heavy oil was pumped into the sanding model at a constant speed. When the pressure difference was stable, the pressure and flow rate were then recorded and the oil phase permeability was calculated.
(8) Experiments on the different thermal recovery methods: Fluid (hot water, steam, and multi-thermal fluid) was pumped into the model at a constant speed, after which the water-free recovery period, water breakthrough time, cumulative oil production and cumulative fluid production were recorded on the basis of the same water equivalent. The experiment was finished when 4 PV fluid was pumped.

2.3. Experimental scheme and parameter design

In this experiment, 80 mesh glass beads were employed to make the sand packed model. The arrangement and size of the particles significantly influenced the permeability of the sand packed model. As compared to the natural core, the sand packed model did not contain cement and allowed point contact between the particles, thereby forming connected pores. Evenly mixed glass beads had a sand packed model permeability that depended largely on the arrangement of the particles and the particle size distribution.

Six groups of sand packed model were generated based on the fabrication process of the sand packed model. The basic parameters of the six groups of sand packed models are presented in Table 1, wherein the physical parameters of the six models are basically the same and the parallelism is high, which is useful for comparative experimental studies. In addition, the sanding model exhibited a water phase permeability between 4919.88 mD and 5073.58 mD, a porosity between 36.93% and 37.65%, and a irreducible water saturation between 9.48% and 10.87%, which is consistent with the properties of Bohai Oilfield. Moreover, the oil sample was selected from Bohai Oilfield.

Under a fixed pressure and as the temperature increased, the phase of water first changed from hot water to saturation water, followed by changes to saturation steam, and finally to superheated steam. Based on these observations, the temperature and pressure settings and the maintenance of the steam/water phase are important factors for the success of this experiment. The saturation temperature of water increased following an increase in the absolute pressure, as presented in Fig. 2. The saturation pressure of saturation steam at 120 °C was observed to be 0.2 MPa. The saturation pressure of saturation steam at 200 °C was 1.6 MPa. The temperature was controlled by the heating device and the pressure was set by the back pressure valve.

3. Experimental results

3.1. Error analysis

The uncertainty refers to the trustworthiness of the measured value due to the existence of the measurement error. In addition, a lower uncertainty results in more reliable experimental results. The uncertainty is determined by all parameters measured in the experiment. From Eq. (1), the uncertainty for u is defined as:

$$u = \sqrt{u_m^2 + u_t^2} \tag{1}$$

where u is the experimental uncertainty, u_m is the uncertainty caused by the measuring cylinder, u_t is the uncertainty caused by time.

Table 1
Basic parameters of sand packed model.

Temperature (°C)	Thermal methods	Permeability (mD)		Porosity (%)	Irreducible water saturation (%)
		Gas	Water		
120	Hot water flooding	8414.33	4936.11	37.37	10.30
	Steam flooding	8291.09	5044.64	37.23	10.54
	Multi-thermal flooding	8312.08	5073.58	37.00	10.87
200	Hot water flooding	8361.28	5059.87	36.93	9.48
	Steam flooding	8549.28	4927.39	37.65	9.66
	Multi-thermal flooding	8214.54	4919.88	37.18	9.59

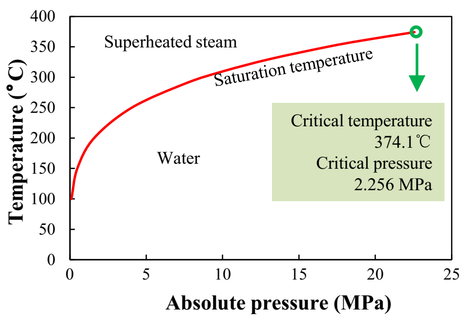

Fig. 2. Saturation temperature of water under different pressures.

The measuring cylinder had an accuracy of ±0.1 and a maximum error of 0.1. The time influenced the presence or absence of a drop of oil into the measuring cylinder. The oil drop had a volume of approximately 0.04 mL, thereby resulting in a maximum largest time error of 0.04. Therefore, the largest error of the experiment is 0.108. The experimental data with an obvious singular point is plotted in Figs. 3 and 4, wherein the experimental data is in good accordance with the regression results, thereby indicating the reliability of the experimental results.

3.2. Effect of the temperature on the water cut

The effect of the temperature on the water cut curves of the different thermal recovery methods is presented in Figs. 5–7. The following observations were concluded based on the results: (a) As compared to the low temperature conditions, the water breakthrough time was extended at high temperatures; and (b) Under high-temperature conditions, the water cut was lower than that at the low-temperature conditions. An increase in the temperature generated a decrease in the viscosity of the heavy oil and improved the oil-water mobility ratio, which contributes to the prolongation of the water-free recovery period and the decrease of the water cut.

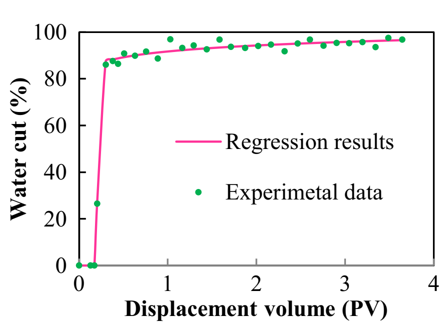

Fig. 3. Water cut as a function of the displacement volume at 200 °C.

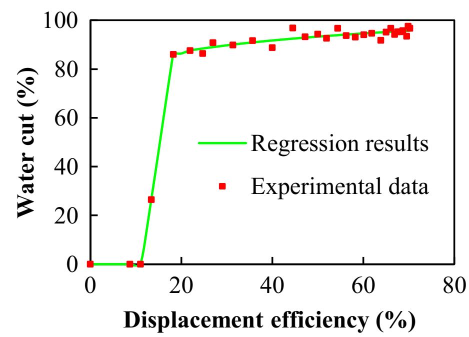

Fig. 4. Water cut as a function of the displacement efficiency at 200 °C.

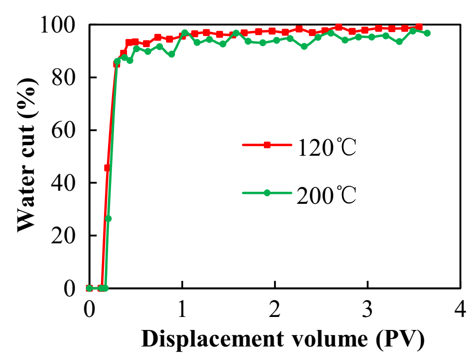

Fig. 5. Water cut curve of hot water flooding.

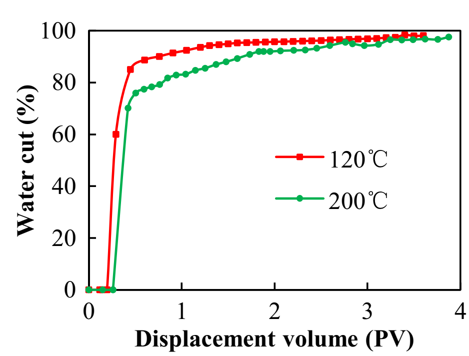

Fig. 6. Water cut curve of steam flooding.

3.3. Effect of temperature on the oil displacement efficiency

The changing trend of the oil displacement efficiency at different displacement volumes is presented in Figs. 8–10, wherein an oil displacement efficiency was observed at high temperatures than at low temperatures. In addition, under the high temperature

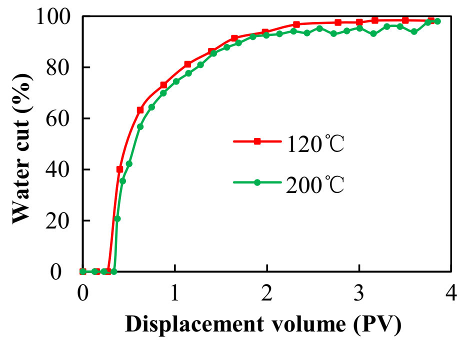

Fig. 7. Water cut curve of multi-thermal flooding.

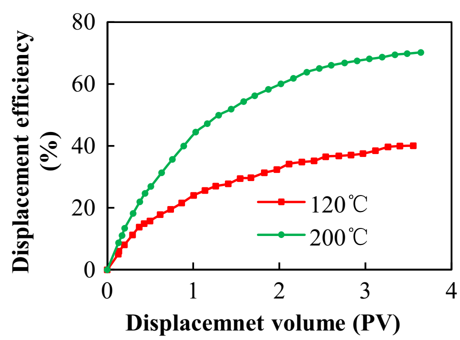

Fig. 8. Displacement efficiency curve of hot water flooding at different temperatures.

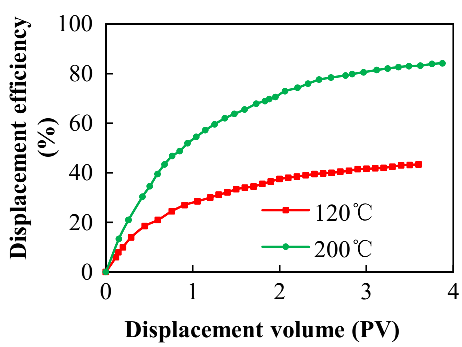

Fig. 9. Displacement efficiency curve of steam flooding at different temperatures.

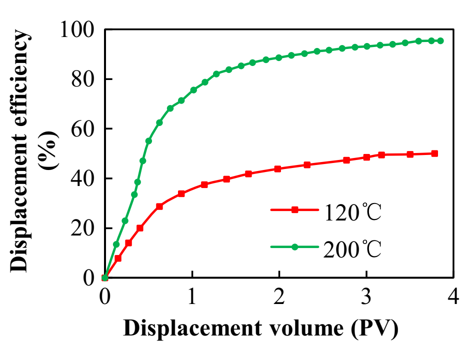

Fig. 10. Displacement efficiency curve of the multi-thermal fluid at different temperatures.

conditions (200 °C), Fig. 11 and Table 2 indicate that: (a) the hot water flooding condition exhibited an oil displacement efficiency increase of 30.15% and an increase in the amplitude of 75.22%;

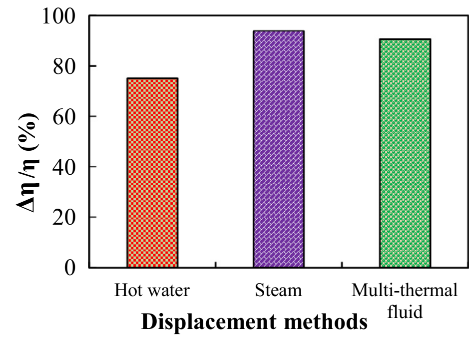

Fig. 11. Increasing amplitude of the displacement efficiency at high temperatures.

(b) the steam flooding condition exhibited an oil displacement efficiency increase of 40.81% and a 94.03%-increase in the amplitude; and (c) the multi-thermal fluid flooding condition exhibited an oil displacement efficiency increases of 45.40% and a 90.73%-increase in the amplitude. Therefore, the increase in the oil displacement efficiency can be ordered according to impact as follows: multi-thermal fluid flooding > steam flooding > hot water flooding. The increase in the oil displacement efficiency amplitude can be ordered according to impact as follows: steam flooding > multi-thermal fluid flooding > hot water flooding.

Some field tests indicated that hot water flooding was better than steam flooding, which was not contradictory with the experiment results. In the actual development of the oilfield, the recovery of heavy oil was a result of displacement efficiency and sweep volume. In addition, steam was easy to channel, which resulted in a better hot water flooding effect as compared to steam flooding.

3.4. Comparison of the development effects of the different thermal recovery methods

3.4.1. Differences in water cut

The effect of the thermal recovery methods on the water cut curve under different temperature conditions is presented in Figs. 12 and 13, of which the results indicated that: (a) Under the same temperature condition, the water-free recovery period can be ordered as follows: hot water flooding < steam flooding < multi-thermal fluid flooding, as presented in Figs. 14 and 15. (b) Under the same temperature condition, water-free oil displacement efficiency can be ordered as follows: multi-thermal fluid flooding > steam flooding > hot water flooding. (c) Under the same temperature and displacement efficiency conditions, the water cut can be ordered as follows: hot water flooding > steam flooding > multi-thermal fluid flooding. (d) Under the same temperature condition, the rate of increase in the water cut can be ordered as follows: hot water flooding > steam flooding > multi-thermal fluid flooding.

According to the experimental results, water channeling was obvious during the hot water flooding process and the water cut increased rapidly following the water breakthrough as compared to steam flooding. In addition, the nitrogen and undissolved carbon dioxide in the multi-thermal fluid slowed the rate of steam condensation to water as compared to steam flooding. The water that moved towards the outlet end was partially inhibited, thereby resulting in a longer water-free recovery period. The presence of nitrogen and carbon dioxide in the multi-thermal fluid resulted in an increased oil-water two-phase permeation zone, a relative permeability curve that shifted to the right, and a isotonic point that also moved rightward, which resulted in a slowly increasing water cut rate.

Table 2
Effect of the temperature on the oil displacement efficiency for the different thermal methods.

Thermal methods	Temperature (°C)	Displacement efficiency (%)	Increment (%)	Increasing amplitude (%)
Hot water flooding	120	40.08	30.15	75.22
	200	70.23		
Steam flooding	120	43.40	40.81	94.03
	200	84.21		
Multi-thermal fluid flooding	120	50.04	45.40	90.73
	200	95.44		

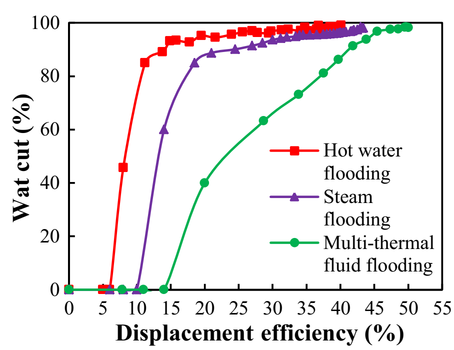

Fig. 12. Water cut curve of the different thermal recovery methods at 120 °C.

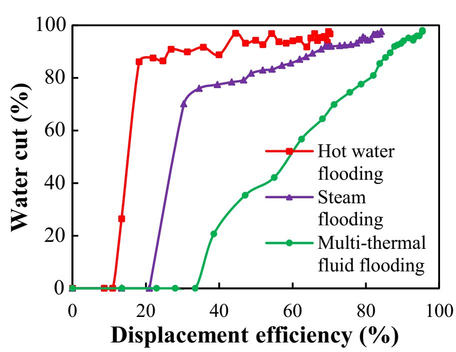

Fig. 13. Water cut curve of the different thermal recovery methods at 200 °C.

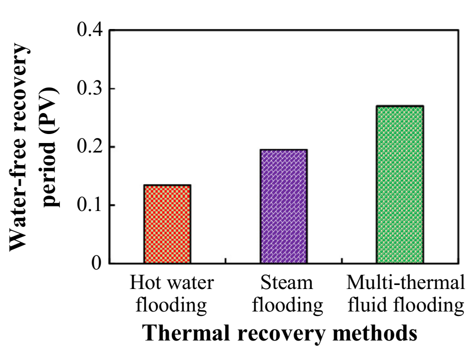

Fig. 14. Water-free recovery period of the different thermal recovery methods at 120 °C.

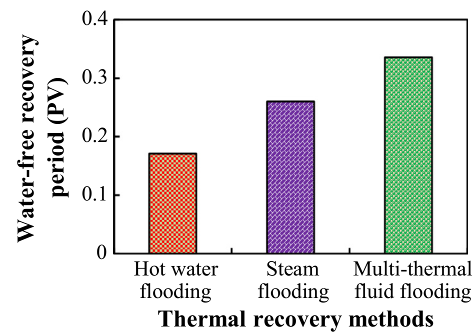

Fig. 15. Water-free recovery period of the different thermal recovery methods at 200 °C.

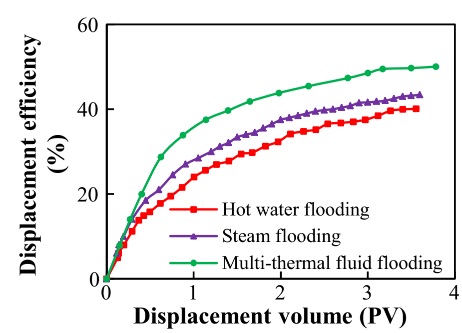

Fig. 16. Displacement efficiency of the different thermal recovery methods at 120 °C.

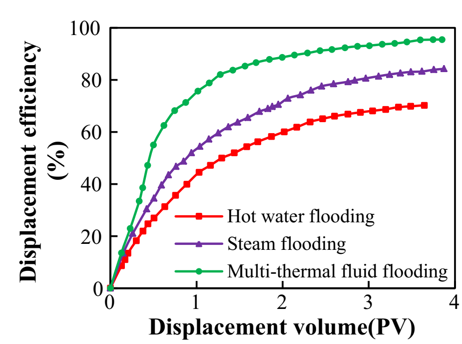

Fig. 17. Displacement efficiency of the different thermal recovery methods at 200 °C.

3.4.2. Differences in oil displacement efficiency

The effect of displacement volume on the oil displacement efficiency at different thermal recovery methods is presented in Figs. 16 and 17, wherein the effect of the recovery methods on the oil displacement efficiency at the same temperature can be ordered as follows: multi-thermal fluid flooding > steam flooding > hot water flooding.

Although the increasing amplitude of the steam flooding displacement efficiency was better than that of the multi-thermal fluid flooding (Fig. 11), the present study recommends the multi-thermal fluid process for the development of offshore heavy oil due to two particular aspects. Firstly, as compared to steam flooding, the displacement efficiency of multi-thermal fluid flooding

Table 3
Results of the heavy oil four components before and after the reaction using the different thermal recovery methods (S+A means saturates and aromatics).

Temperature (°C)	Thermal recovery methods	Asphaltene (%)	Resin (%)	Aromatics (%)	Saturates (%)	S+A (%)
Heavy oil		0.23	25.96	25.73	26.38	73.81
120	Hot water flooding	0.45	26.49	26.88	30.79	73.06
	Steam flooding	0.71	25.01	25.26	34.94	74.28
	Multi-thermal fluid flooding	0.98	22.77	26.43	36.48	76.25
200	Hot water flooding	0.98	25.68	25.99	32.21	73.34
	Steam flooding	1.19	24.08	27.40	33.40	74.73
	Multi-thermal fluid flooding	1.48	21.62	24.90	35.64	76.90

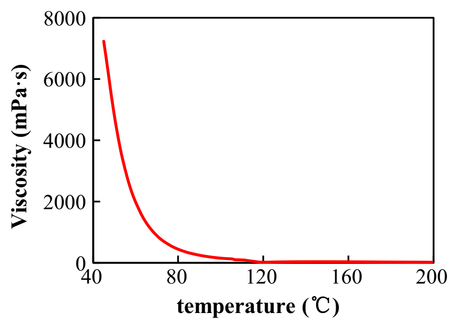

Fig. 18. Viscosity-temperature curve of the heavy oil.

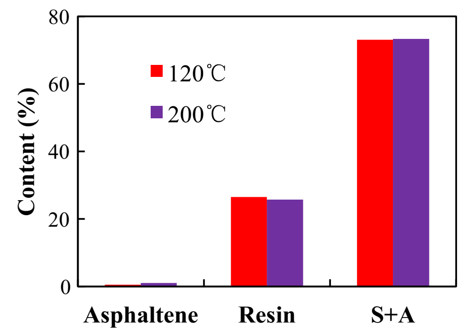

Fig. 19. Distribution diagram of the four components at different temperatures.

exhibited an improvement of 6.64% at 120 °C and an increase of 11.23% at 200 °C, which indicates that multi-thermal fluid flooding is better than steam flooding under the same temperature condition. Secondly, due to current low oil prices, the development of offshore heavy oil focuses on efficiency and the economy. Although the composition of the multi-thermal fluid includes additional nitrogen and carbon dioxide as compared to steam, the multi-thermal fluid process has the following strengths: better oil development effect, abundant air source, low cost, and good economic benefits.

4. Study on the mechanism of the different thermal recovery methods

4.1. Analysis of the heavy oil component at different thermal recovery methods

Heavy oil is a complex and multi-component organic mixture that consists mainly of saturates, aromatics, resin, and asphaltene (SARA, also called four components). The oil development process itself and the application of certain recovery techniques destroys the balance of the components between the asphaltene solution and the resin system of heavy oil in the reservoir, which results in changes in the components contents in the developed heavy oil. Therefore, it is necessary to determine the content of the four components in the heavy and developed heavy oils at different temperatures and at different thermal recovery methods to further examine and improve the recovery mechanism of the different thermal recovery methods, as shown in Table 3. Given that the saturates and aromatics are light volatile components, the total yield of heavy oil is less than 100%. However, this does not affect the accuracy of the content results of the resin, asphaltene, and the aromatics+saturates.

According to the measurement results of the four components, the content of asphaltene and the saturates+aromatics in heavy oil are gradually increased from hot water flooding to steam flooding and then to multi-thermal fluid flooding under the same temperature condition. However, the content of resin gradually decreased. Higher temperatures resulted in higher asphaltene contents and lower resin content in the developed heavy oil under the same thermal recovery methods, though the content of the aromatics + saturates exhibited minimal changes.

4.2. Recovery mechanism of the different thermal recovery methods

Thermal recovery is characterized as the most effective way to develop heavy oil. In addition to relying on heat to reduce the viscosity of heavy oil, an injected agent aids in the aquathermal cracking reaction of the heavy oil, thereby resulting in SARA content changes [46–53]. In essence, the recovery mechanisms of the different thermal recovery methods are not the same.

4.2.1. Hot water flooding

The viscosity change trends of the heavy oil at different temperatures were measured using an Anton Paar rheometer (provided by Anton Paar GmbH, Shanghai, Beijing), as shown in Fig. 18. An increase in temperature generated a significant decrease in heavy oil viscosity. When temperatures are higher than 105 °C, heavy oil viscosity will decrease slightly. This result indicates that: (a) When temperature was lower than 105 °C, temperature significantly influenced the heavy oil viscosity reduction; (b) The reduction in viscosity helped improve the oil-water mobility ratio; (c) When temperature was higher than 105 °C, temperature exhibited minimal influence on heavy oil viscosity, and an increase in the temperature was equivalent to an increase in the heat expanding heating region. In addition, Fig. 19 indicates that the four components of the developed heavy oil exhibited minimal changes from 120 °C to 200 °C. Therefore, the viscosity reduction and thermal expansion of heavy oil can be characterized as the principle mechanisms during the heating process. This also explains the trend observed in hot water flooding, wherein higher temperatures resulted in higher oil displacement efficiencies and minimal in the four components of the developed heavy oil.

The previous analysis indicates that: (a) The viscosity reduction is the principle mechanism of hot water flooding; (b) Improvements in the oil-water mobility ratio helped generate a relatively

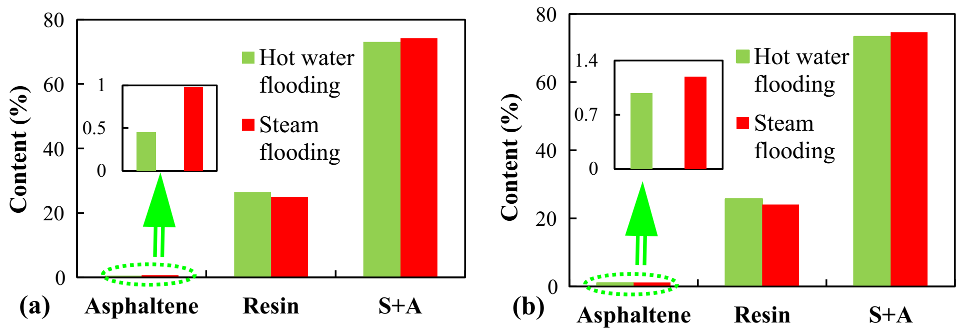

Fig. 20. Comparison of the four components content between hot water flooding and steam flooding at (a) 120 °C, and (b) 200 °C.

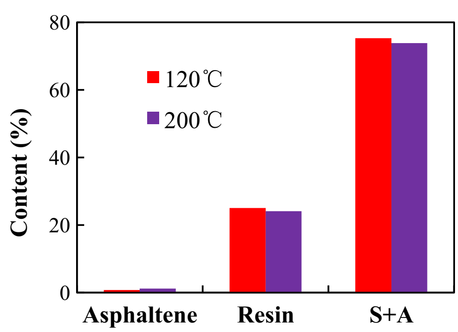

Fig. 21. Content of the four components following steam flooding at different temperatures.

uniform flow profile distribution and improved the oil displacement efficiency; and (c) Changes in four components content following hot water flooding were not obvious.

4.2.2. Steam flooding

According to the curve changes of the oil displacement efficiency (Figs. 16 and 17), steam flooding was better than hot water flooding. The results of the developed oil four components (Fig. 20) indicate that the four components of the heavy oil exhibited more obvious content changes than that of hot water flooding. In addition, Fig. 21 indicated that the four components of the developed heavy oil exhibited more obvious changes at higher temperatures, which indicates the execution of the aquathermal cracking reaction.

Following gas breakthrough, the liquid hydrocarbons condensed on the walls of the metering device, thereby demonstrating the importance of steam distillation. In addition, the introduction of the "false mobility ratio" concept, see Eq. (2), was employed to consider the volume change and the gas-drive effect following steam injection, which indicates that a large number of injected steam can improve the recovery conditions, reduce residual oil saturation, and enhance oil recovery. Therefore, in addition to the viscosity reduction and thermal expansion, steam distillation and the gas-drive effect were also characterized as principle mechanisms for steam flooding.

$$M = \frac{K_s}{K_o}\frac{\mu_o}{\mu_s} \tag{2}$$

where K_s is the effective permeability of steam (mD), K_o is the effective permeability of oil (mD), μ_s is the viscosity of steam (mPa·s), and μ_o is the viscosity of oil (mPa·s).

The following conclusions were drawn based on a combination of previous observations with the analysis of this part: (a) The reduction in viscosity is also a principle mechanism of steam flooding; (b) Steam distillation generated obvious improvements in the oil displacement efficiency; (c) Content changes in the four components of the heavy oil indicated that a certain degree of aquathermal cracking reaction occurred between the heavy oil and steam; and (d) On the basis of the aquathermal cracking reaction, extraction was more likely to occur.

4.2.3. Multi-thermal fluid flooding

The oil displacement efficiency curves of hot water flooding, steam flooding, and multi-thermal fluid flooding are presented in Figs. 16 and 17. According to the experimental results, the oil displacement efficiency of multi-thermal fluid flooding greatly improved with respect to steam flooding and hot water flooding due to the properties and synergistic effect of the gas in

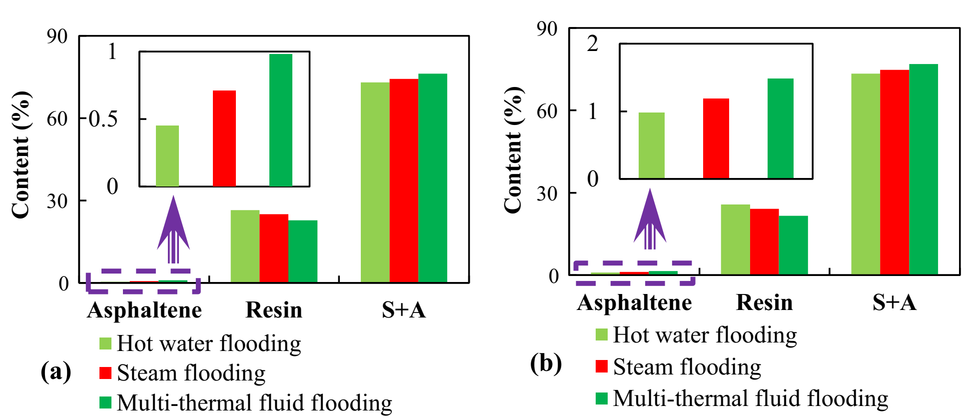

Fig. 22. Comparison of the contents of the four components following hot water flooding, steam flooding, and multi-thermal fluid flooding at (a) 120 °C, and (b) 200 °C.

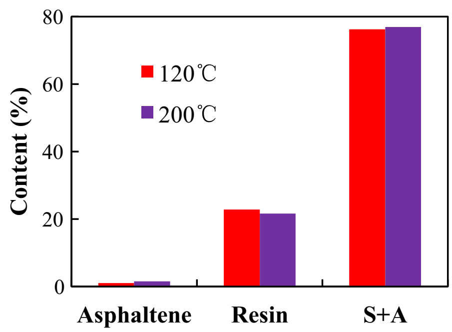

Fig. 23. Four components content after multi-thermal fluid flooding at different temperatures.

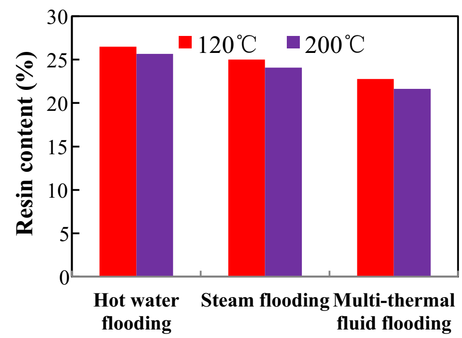

Fig. 25. Changes in the resin content at different thermal recovery methods.

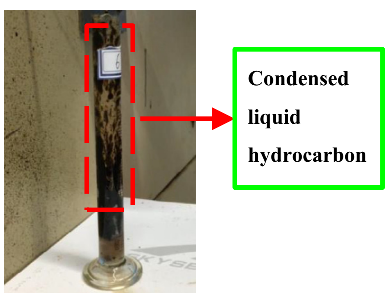

Fig. 24. Condensate phenomenon during multi-thermal fluid flooding.

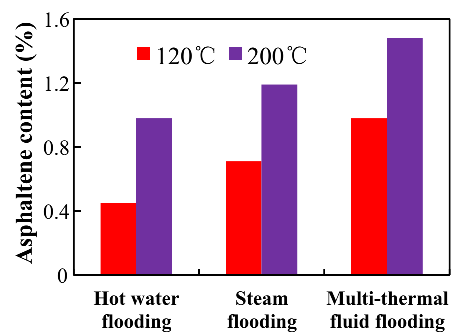

Fig. 26. Changes in the asphaltene content at different thermal recovery methods.

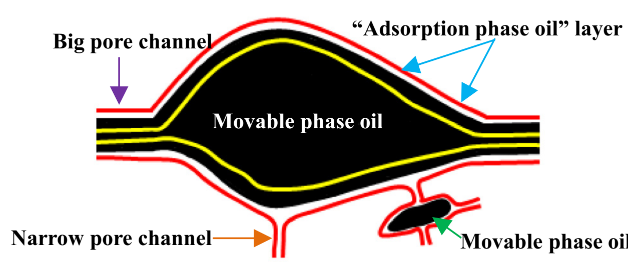

Fig. 27. Schematic diagram on distribution of movable phase and adsorption phase oil in reservoir pore.

multi-thermal fluid. According to Fig. 22, the content of four components in the heavy oil that were developed from multi-thermal fluid flooding exhibited more obvious changes as compared to those of hot water flooding and steam flooding. In addition, at the same temperature, the content of asphaltene in the developed heavy oil was higher than that in steam flooding and hot water flooding. Moreover, according to Fig. 23, higher temperatures generated more significant changes in the four components of the developed heavy oil, thereby indicating the importance of aquathermal cracking in improving the oil recovery.

In the course of the experiment, specifically during gas breakthrough, the liquid hydrocarbon condensed on the wall of the metering device (Fig. 24). This phenomenon was significantly obvious as compared to the steam flooding experiment, thereby indicating the enhancement of the steam distillation process following the injection of gas. Moreover, heavy oil is bead-shaped and is easily separated from water during multi-thermal fluid flooding. However, during the course of the experiment, heavy oil developed continuously and was difficult to separate from water during steam flooding. Due to the compression and expansion effect of nitrogen which changed the flow pattern of the heavy oil, this phenomenon became more obvious following the injection of gas. As a result, acting forces among heavy oil particles reduced and flowability of heavy oil was enhanced.

Nitrogen has a large compression coefficient due to its lower critical temperature and minimal dependence on temperature. Its good expansibility and small solubility helps maintain its formation pressure and form power flooding. In addition, it has weak solubility in heavy oil and water. As a result, nitrogen forms microbubbles in the formation, promotes steam migration, enhances the heat carrying capacity of steam, strengthens the heat exchange between steam and heavy oil, and improves the thermal recovery result of heavy oil, all of which are consistent with the findings of Liu et al. [34].

The Jia Min effect [21] is observed when nitrogen blocks narrow pores and throats and then adjusts the gas injection profile, thereby resulting in evenly spread gas, which adjusts to the gas channeling phenomenon and expands the sweep volume. However, after entering the reservoir, nitrogen preferentially occupies the oil passage in the porous medium, which generates mobile oil from the original bound oil and reduces the residual oil saturation, which is consistent with the results of Li et al. [22].

Yang et al. [54] indicated that the minimum miscible pressure (MMP) of low-temperature light oil and heavy oil are 8.27 MPa and 31.03 MPa, respectively. Given that the experimental conditions did not meet the MMP between carbon dioxide and heavy oil, the displacement experiment was a non-miscible displacement and the non-miscible flooding was characterized as the principle mechanism of carbon dioxide. Following carbon dioxide dissolution in the heavy oil, molecular attraction and interfacial tension between the oil and water decreased. The viscosity of heavy oil decreased and the oil-water mobility ratio improved effectively, thereby resulting in an increase in the displacement efficiency, as verified by Khatib [55]. In addition, following the dissolution of carbon dioxide in heavy oil, the volume of the system expanded, the elastic energy increased, the density of the heavy oil reduced,

Table 4
Recovery mechanism of the different thermal recovery methods.

Thermal recovery methods	Hot water flooding	Steam flooding	Multi-thermal fluid flooding
Recovery mechanism	• Viscosity reduction by heat • Thermal expansion • Improve oil-water mobility ratio	• Viscosity reduction by heat • Steam distillation • Aquathermal cracking reaction • Extraction effect	• Viscosity reduction by heat • Aquathermal cracking reaction • Viscosity reduction by dissolution effect • Gas-water hybrid drive
Disadvantages	– Water carries less heat – Viscosity reduction effect is limited	– Easy to steam channeling – Low sweep volume	–

the flow resistance reduced, and the flowability improved, all of which are beneficial for the development of heavy oil.

The following observations were concluded based on the above analysis: (a) Viscosity reduction is the principle mechanism of multi-thermal fluid flooding; (b) Significant content changes were observed in the four components of the heavy oil, which characterize aquathermal cracking as the main way to improve the recovery of oil; (c) The dissolution of CO_2 improved the oil displacement efficiency mainly through the reduction of viscosity; and (d) N_2 formed a hybrid flooding between gas and water, which improved the oil-water mobility ratio and the oil displacement efficiency.

At the same thermal recovery method, higher temperatures resulted in lower resin contents, as presented in Fig. 25, because the resin in the heavy oil played a very important role in the migration of asphaltene. An increase in the temperature decreased the adsorption capacity of the resin on the surface of the asphaltene particles and increased the solubility of the resin in the heavy oil, all of which significantly influenced the migration of asphaltene. However, the flow resistance of the resin itself increased dramatically, which reduced the amount of developed resin.

At the same recovery method, a higher temperature resulted in a higher asphaltene content in the developed heavy oil, as presented in Fig. 26, because the CO_2 in the multi-thermal fluid reduced the pH of the system, thereby destroying the balance of the aromatics-resin-asphaltene system in the heavy oil and changing the components of the heavy oil. Fig. 27 presents the distribution of the movable phase and the adsorption phase oil in the reservoir. The oil in the small pores presented in Fig. 27 was supposed to be recoverable. However, the oil transformed into dead oil and was difficult to develop due to large pore blockage in the channel by the asphaltene adsorbed on the surface of the minerals. An increase in the temperature gradually thinned the adsorption layer and enhanced the heat capacity of the nitrogen in the multi-thermal fluid, thereby enhancing the production of asphaltene.

Based on the above analysis, the mechanisms of hot water flooding, steam flooding and multi-thermal fluid flooding are presented in Table 4.

5. Conclusions

The present study developed a new experimental scheme to examine the mechanism of enhanced oil recovery by a multi-thermal fluid in offshore heavy oil. A feasibility experiment was executed under hot water flooding, steam flooding and multi-thermal fluid flooding conditions. The experimental phenomena and stimulation mechanism of the multi-thermal fluid flooding methods were analyzed and compared with hot water flooding methods and steam flooding methods. The following conclusions were developed based on the experimental analysis and results:

(1) Thermal viscosity reduction and thermal expansion are the principle mechanisms of hot water flooding. In addition, improvements in the oil-water mobility ratio further improved the oil displacement efficiency.
(2) Thermal viscosity reduction and steam distillation are the principle mechanisms of steam flooding. In addition, aquathermal cracking reaction and the extraction effect further improved the oil displacement efficiency.
(3) Thermal viscosity reduction and aquathermal cracking reaction are the principle mechanisms of multi-thermal fluid flooding. In addition, due to the synergistic effect of nitrogen and carbon dioxide, the multi-thermal fluid increased the recovery of heavy oil by supplementing the formation energy, expanding the sweep volume, dispersing and improving the flow pattern of heavy oil, forming non-miscible displacement, and improving the heat utilization of steam.
(4) The multi-thermal fluid changed the balance of the aromatics-asphaltene-resin regime by the thermal/physical/chemical mechanism, which strengthened the developmental degree of the asphaltene component in the heavy oil, and thus improved the oil recovery rates.

Conflict of interest

The authors declare that there are no conflict of interest.

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