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# Experimental Investigation of Steam Conformance Evolution in Vertical-CSS and Optimization of Profile Improvement Agents

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**Abstract:** Production performance of heavy oil deposits in Xinjiang oilfield developed by vertical-well cyclic steam stimulation (CSS) is increasingly challenged by reservoir heterogeneity, which is comprised of original sedimental heterogeneity and steam-induced heterogeneity. In order to understand the impacts of sedimental heterogeneity and high-speed steam injection to steam conformance, and strategies to maximize steam swept volume, a series of experiments were designed and implemented. Three-tube coreflooding experiments were performed to study the steam displacement dynamics under heterogeneous conditions, and a high-temperature plugging agent was developed. The coreflooding experiments indicate that the injection conformance deteriorates once the steam breakthrough occurs in a high-permeability tube, leaving the oil in the medium and low permeability tubes being surpassed. The optimized plugging agent could resist high temperatures over 260 °C and its compressive strength was 13.14 MPa, which is higher than maximal steam injection pressure. The plugging rate of high permeability core was greater than 99.5% at 220–280 °C with a breakthrough pressure gradient over 25 MPa/m. The field test validated its profile improvement feasibility with cyclic oil, 217.6% of the previous cycle. The plugging agent optimized in this study has significant potential for similar heterogeneous reservoirs.

**Keywords:** CSS; heavy oil; heterogeneity; steam conformance; plugging agent

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## 1. Introduction

Steam conformance is a key factor in steam-based recovery processes of heavy oil reservoirs [1–5]. Due to different sedimentation backgrounds in the formation, different sedimentation results in different rock types and properties, and the difference in lithology causes the reservoir heterogeneity. Meanwhile, the CSS process of vertical wells always needs to inject a large amount of steam into the payzone during a limited period, which requires an injection speed of normally more than 80 $m^3$/d(CWE). Fast injection with high pressure and high temperature tends to creep the oil sand and leads to mini-fractures in high-permeability zones [6,7]. It has been found that multi-cycles of steam injection extend the fractures with steam and the reservoir heterogeneity deteriorates.

Extensive studies have been carried out to understand the reservoir heterogeneity, both for lithology and rock mechanics. Moreover, the literature has proposed some useful strategies to improve the steam conformance, such as high-temperature gas foam with steam [8,9], an oil viscosity reducer or solvent to increase the injection capacity and reduce the fractures [10–12], and thermoreversible gel to plug the steam channels [13]. Polymer gels are potential plug agents to solve near wellbore issues. Researchers have found a new HPAM gel formula that could be stable for more than 7 days at 175 °C, while a co-polymer with heat resistance groups was found to improve the applied temperature to 200 °C. Filed applications in four vertical wells and one horizontal well have demonstrated that the gel plugs are applicable in a wide range of wellbore temperatures, from 60 °C to 191 °C [14]. Moreover, a review article discussed polymer gel techniques from innovations to applications. The development of polymer gels to resist temperature, early gel formation, synergistic mechanisms and influence of pH, and high salinity is the future trend to meet harsh reservoir conditions [15].

Other researchers have proposed that an oil-in-water (O/W) emulsion could be an innovative conformance control technology due to its strong plugging ability [16]. They used parallel-sandpack flow tests with the permeability ratios of 4:1 and 5:1 to investigate the performance of conformance control by O/W emulsion injection. They found that a carefully designed O/W emulsion of droplets can deform and migrate deeply into both the high permeability sandpack and the low permeability sandpack, leading to an ideal fractional flow ratio (0.5:0.5) and achieving a good conformance control in the parallel-sandpack model.

FCD/ICD is also an effective downhole tool to improve the distribution of steam in the wellbore [17,18], while it only takes effect in allocating the steam in the wellbore, which is effective at the early production stage, while ineffective at the late production stage as the steam tends to redistribute and converge in the inter-well region.

The well configuration and well pattern can be modified to change the streamline of injected fluid [19,20], while the systematic workover requires a substantial operational cost and the valid period is unknown. Parameters can be optimized for integral wells' management [21,22], but for wells in harsh reservoir conditions or those with severe steam channeling problems, the alteration of operational parameters can hardly take effect due to the preferential streamlines of steam in porous media.

For wells with no further oil recovery potential, they can be converted to other follow-up recovery methods [23]. The evolution of heterogeneity and its fundamental impacts on steam conformance and liquid production rate for different permeability and heterogeneity levels in the process of steam injection has not been fully understood, and the steam profile control strategies after steam channeling and the well-to-well fracture communication need to be optimized. Thus, the aim of this study is to experimentally investigate the evolution of heterogeneity and steam conformance in the steam injection process and strategies for cost-effective steam profile control.

## 2. Materials and Methods

### 2.1. Materials

#### 2.1.1. Brine

Table 1 lists the typical composition of the formation brine used in the experiments. The pH of the formation brine was 7.5. In the experiments, synthetic brine was prepared according to the composition of the formation brine. The concentration of total dissolved solids (TDS) was 6751.3 mg/L.

**Table 1.** Composition of the formation brine (Unit: mg/L).

| Ion | $K^+$ | $Na^+$ | $Ca^{2+}$ | $Mg^{2+}$ | $Cl^-$ | $HCO_3^-$ | $SO_4^{2-}$ | TDS |
|---|---|---|---|---|---|---|---|---|
| Concentration, mg/L | 31.3 | 2615.8 | 37.9 | 11.1 | 3257.0 | 1570.4 | 13.2 | 6751.3 |

#### 2.1.2. Oil

The heavy oil used in the experiments was collected from a typical super heavy oil reservoir of Xinjiang oil field, China. The oil has a density of 0.911 g/cm$^3$. At temperature 50 °C, the oil had a viscosity of 13,356 mPa·s.

#### 2.1.3. Sandcore

Due to the lithology heterogeneity from the fluvial sedimentation environment, the core at different locations of the formation has quite different permeability. As shown in Figure 1, three typical core sands extensively distribute in the formation, which are coarse sand, fine sand, and muddy sand. In order to investigate the steam flow dynamics in a real underground situation, three core types were obtained from the laboratory. The length and diameter of the core samples used in the experiments were 30 cm and 2.5 cm, respectively. In order to match the length of the coreholder, different core samples from the same location connected to reach a length of 30 cm.

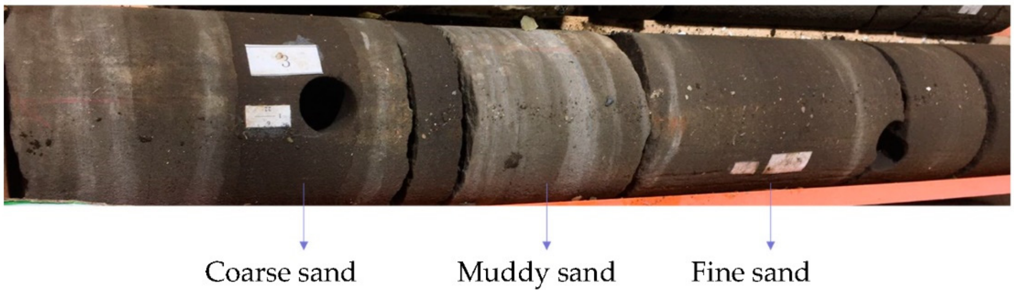


**Figure 1.** Lithology heterogeneity of the formation.

### *2.2. Three-Tube Coreflooding Experiments*

#### 2.2.1. Apparatus

A one dimensional coreflooding experiment system was used in this study, which is schematically illustrated in Figure 2. Three cores described above were used in these experiments. The permeability of three core samples was measured first and the air permeability of coarse sand, fine sand, and muddy sand in the coreholder was 1513 mD, 1028 mD, and 497 mD, respectively. Other parameters of three coreholders are listed in Table 2. The injection pressure data was gathered in surveillance software, and the outlet oil and water were gathered, separated, and metered in detail using the metering module. Particularly, the steam pressure is controlled by injection pump, and steam temperature is preset on the control panel of the boiler.

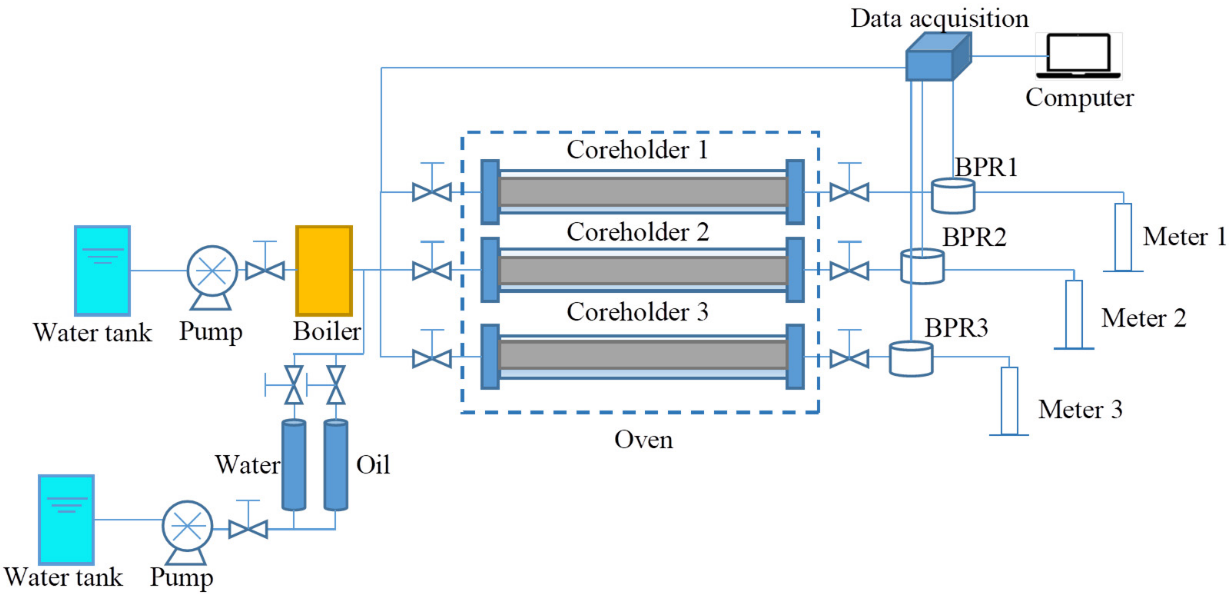


**Figure 2.** Schematic of experimental setup for 3-tube coreflooding experiments.

**Table 2.** Parameters of 3-tube coreflooding experiment.

| Items | Core Holder 1 | Core Holder 2 | Core Holder 3 |
|---|---|---|---|
| Porosity, % | 34 | 33 | 30.1 |
| Permeability, mD | 1513 | 1028 | 497 |
| Oil saturation, % | 91.1 | 91.1 | 91.1 |
| Pipeline dead volume, mL | 5 | 5.3 | 4.5 |
| Core pore volume, mL | 51.7 | 50.1 | 45.6 |

#### 2.2.2. Procedures

The experimental procedures in the one dimensional three-tube coreflooding experiments are given as follows.

(1) Preparation. Three coreholders were installed integrally in the experiment. Then, permeability tests for each sandpack were measured. As the core samples were different from the man-made Berea core, no steps were needed to saturate oil and water. The porosity and oil saturation were measured after coreflooding experiments according to the oil output, which was also different from the conventional coreflooding experiments.
(2) Oil displacement. The backpressure of the sandpacks was maintained at the target bottomhole condition of 0.5 MPa during all experiments. The steam injected had a temperature of 273 °C and maximal injection pressure of 10 MPa, which was the same with field steam injection pressure of CSS process. The steam injection rate ranged from 0–1.5 mL/min, which is affected by injection pressure control and the injection capacity of the cores. The coreflooding did not stop until the outlet watercut reached 98%.
(3) Data analysis. The injection pressure, temperature, volume, etc., were gathered using software, and the produced liquid was gathered using the HTHP gathering and metering module. During experiments, the produced liquid was gathered every 10–30 min, and the water and oil production were obtained accordingly after analysis.

### *2.3. Plugging Agent Optimization Experiments*

#### 2.3.1. Apparatus

The apparatus employed in this experiment included the HT performance tests for plugging agents and one-dimensional coreflooding plugging tests. The HT performance tests included the high-temperature consolidation performance and temperature resistance. The apparatus used in the coreflooding plugging tests is the same at that used with the 3-tube coreflooding test. The major difference is that it uses one sandpack every test instead of three coreholders to evaluate the HTHP plugging performance of agents to cores at different permeability levels.

#### 2.3.2. Procedures

The high-temperature conformance experiments include the following procedures:

(1) Mixing the plugging agent and the quartz with the mesh size of 20–40 (weight proportion is 3:7).
(2) Packing the mixture into the glass tube with 30 mm in diameter and 40 mm in length, and placing it into the high-temperature aging oven.
(3) Adding water into the glass tube and closing the oven under a specified temperature for one week.
(4) Taking the glass tube out and checking the consolidation status, and cutting and grinding it into regular cylinders.
(5) Placing it on a universal pressure machine to test the compressive strength.

The coreflooding plugging experiment procedures are as follows:

(1) Packing the sand with the mesh size of 80–120 into the sandpack model.

(2) Vacuuming the sandpack and testing the water-based permeability $K_{w1}$.
(3) Injecting the HTHP plugging agent, in which the injected volume equals the pore volume of the sandpack; after injection, closing the inlet and outlet.
(4) Keeping the sandpack in the oven with steam injection temperature 273 °C for 8 h.
(5) Testing the water-based permeability $K_{w2}$ And gathering the pressures at the inlets and outlets.
(6) Calculating the plugging ratio and pressure gradient of water breakthrough.

## 3. Results

### *3.1. Three-Tube Coreflooding Experiment Performance*

#### 3.1.1. Production Dynamics

From the oil and liquid rate curves of each sandpack with time (Figures 3 and 4), the total steam displacement can be divided into three phases: early stage (the first stage), pressure and fluid communication establishment stage (the second stage), and steam breakthrough stage (the third stage).

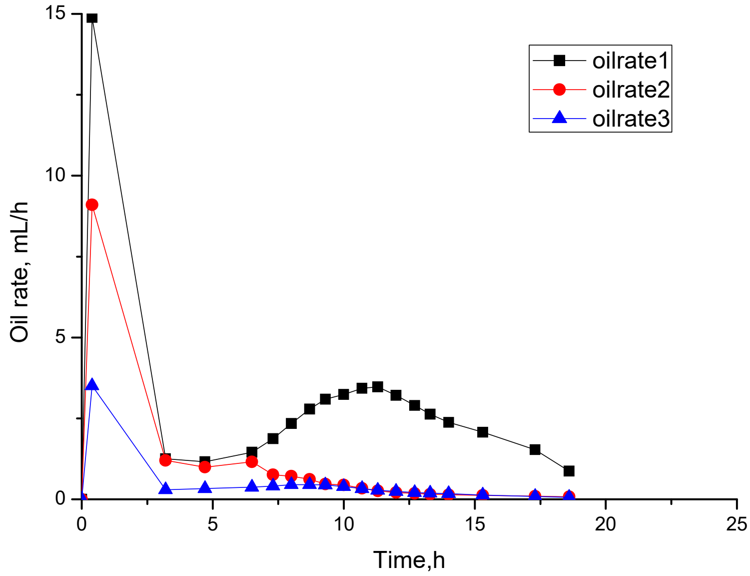


**Figure 3.** Oil production rate curves in each coreholder with time.

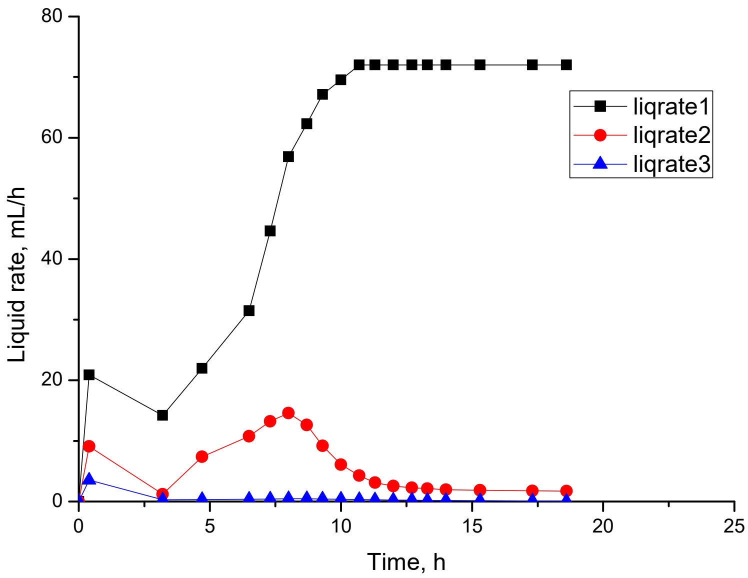


**Figure 4.** Liquid production rate curves in each coreholder with time.

At the early stage, oil was produced from each sandpack under the pressure difference of the initial sandpack pressure and back pressure at the outlet, which is also called the pressure depletion stage, during which the displacement pressure did not reach the outlet and the production drive force is from the pressure differential between back pressure and initial pressure in the coreholder. The oil production of the three cores was 8.1 mL, 3.5 mL, and 1.4 mL. As the pressure in the sandpack depleted rapidly, the pressure difference could not maintain a high production rate, which led to a fast decline in production rate of each sandpack.

During the pressure and fluid communication establishment stage, the displacement pressure transferred from inlet to outlet steadily, which can be validated by the slow enhancement of the liquid rate. Another evident characteristic is that during pressure advancement, the high-permeability coreholder achieved the pressure communication first, while the other two coreholders with lower permeability were yet to be pressure communicated, which resulted in the massive rise of liquid and oil rate in the high-permeability coreholder and the increasing difficulty of steam into the other two low-permeability coreholders, and the liquid and oil rate in these two coreholders declined accordingly. In the medium-permeability coreholder particularly, the change of production rate was evident, the fundamental reason is that different permeability corresponds to a different pressure advancement rate and communication time, which leads to different injection capacity and production rate.

During the third stage, which is characterized as steam breakthrough in the high-permeability coreholder, the steam displacement performance was the best in this coreholder, while in this steam channeling route, the steam which was supposed to drive oil in the other two coreholders, entered into this route, causing massive enhancement of the liquid rate and a rapid decline of the oil rate. Meanwhile, as steam surpassed the medium-permeability coreholder, the liquid rate declined rapidly and there was almost no liquid output at the displacement end, which is similar to the field production performance.

The steam injection into each sandpack was 17.11 PV, 1.73 PV and 0.12 PV, which was calculated according to the liquid production in each coreholder. The cumulative oil of the three coreholders was 44.1 mL, 13.9 mL, and 6.2 mL. The corresponding oil displacement efficiency was 84.9%, 17.26%, and 13.55%. It should be noted that the previous steam absorbing coreholder became unabsorbed after the steam breakthrough in the high-permeability coreholder, while the low-permeability coreholder did not absorb steam at all [2].

The watercut dynamics also witnessed different watercut rises in coreholders (Figure 5). The earliest water output time and highest watercut rise rate in the high-permeability coreholder means during commingle steam injection in the field, the primary displacement target was the high-permeability zone. The watercut in the medium-permeability coreholder rose relatively slow while it also reached over 90%, which means that the steam injected during the first stage reached the outlet under the pressure difference, while a small, condensed water rate could hardly drive the oil out.

### 3.1.2. Pressure Dynamics

As shown in Figure 6, during the displacement experiment, pressure control strategies were implemented. The initial injection pressure was 10 MPa, which is higher than the fracture pressure of payzone in the field, and the back pressure was 0.5 MPa, while the injection pressure declined rapidly after steam breakthrough. In order to inhibit the steam channeling, the back pressure in the high-permeability coreholder was enhanced steadily to 1.7 MPa, while no liquid rate rise occurred in the other sandpacks. It was found that the high-pressure steam injection could induce hydraulic fractures in the high permeability region, which is adverse in the steam injection process [7]. At the late stage, the back pressure of the high-permeability core was further regulated several times and to 1.05 MPa at the end of displacement, with the injection pressure of 1.09 MPa.

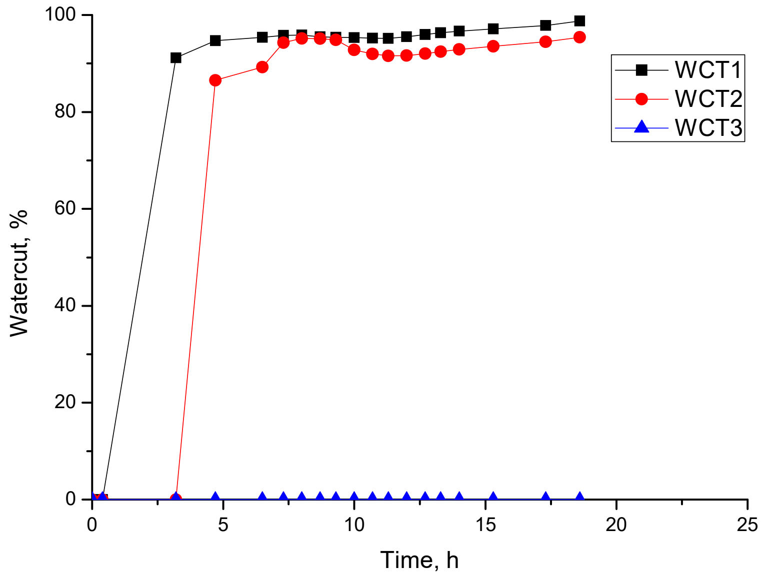


**Figure 5.** Watercut curves in each coreholder with time.

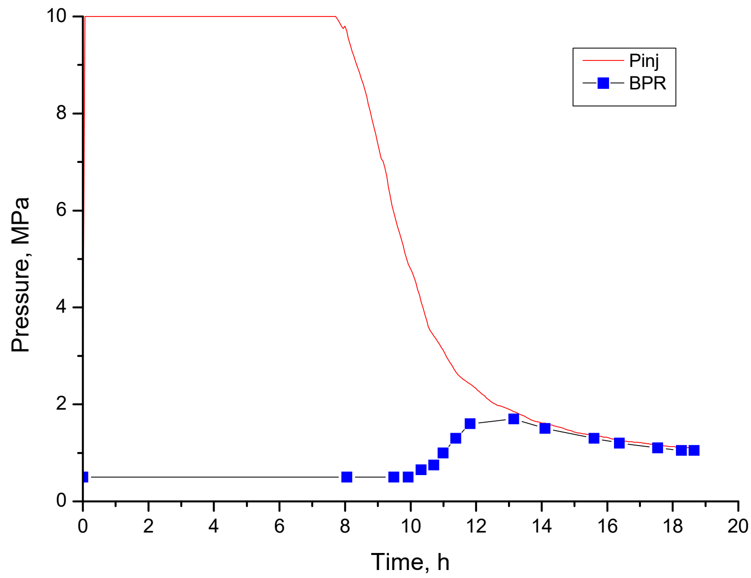


**Figure 6.** Injection pressure and back pressure of high-permeability coreholder with time.

It is evident that the pressure differential declined constantly as the steam injection process continued, which is a reflection of deterioration of steam channels, and also indicates that some strategies should be put-forward to improve the steam conformance as soon as possible.

### 3.1.3. Oil Displacement Profile

As the liquid from each outlet was metered separately, it was able to calculate the liquid profile for three coreholders, such as three payzones in the field operation. Figure 7 includes the liquid profile at 4.7 h, 8.0 h, and 11.3 h. From the comparison, it is shown that the liquid rate proportion from the medium-permeability coreholder was 24.9% at the early stage, while it declined to 20.3% after 8 h of displacement, and further reduced to 4.1% at the displacement end. On the contrary, that of the high-permeability coreholder rose from 74% to 95.9%. This means the formation heterogeneity deteriorates in the long-term steam injection process, and the dynamic permeability ratio (max/min) is much higher than the initial condition [17].

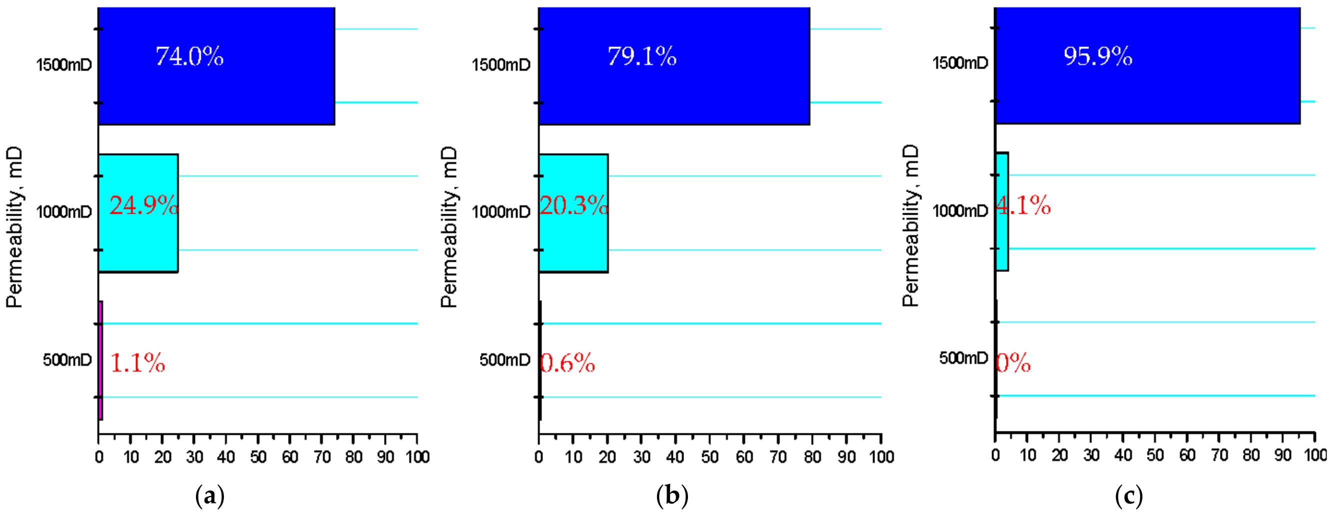


**Figure 7.** Liquid rate proportion at different steam injection periods. (**a**) 4.7 h (**b**) 8.0 h (**c**) 11.3 h.

### *3.2. Plugging Agent Optimization Results*

#### 3.2.1. High-Temperature Consolidation Performance

The consolidation performance of high-temperature plugging agents HTP, HTE, HTF, and HTG, was analyzed and compared at different temperatures through experiments (test conditions: the proportion of quartz sand was 70% and the aging time was 8 h), and the results are shown in Figure 8.

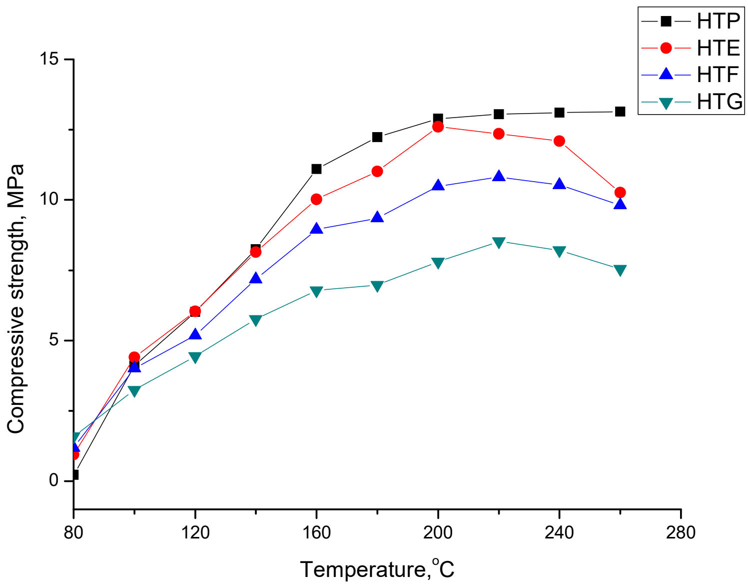


**Figure 8.** Consolidation performance of HTP at different temperature levels.

It is shown in Figure 8 that the HTP outperformed the other three agents. Temperature has a great influence on the compressive strength of the consolidated body formed by quartz sand and plugging agent [24]. When the temperature was 80 °C, the compressive strength of the consolidated body was very low, but with the increase of temperature, the compressive strength of the consolidated body continued to increase, and when the temperature reached 160 °C, the compressive strength of the consolidated body using HTP reached 11.1 MPa. However, when the temperature rose again, the further increase in the compressive strength of the consolidated body decreased. It was found that when the temperature was higher than 180 °C, the consolidated body had volume expansion phenomenon and was tightly and firmly cemented with glass tube, indicating that HTP can be well cemented with sandstone formation and has a high consolidation strength (higher than maximal steam injection pressure 12.8 MPa), while the maximal pressure resistance of the other three plugging agents was lower than 11 MPa. Therefore, HTP is suitable as a plugging agent for the steam-based thermal recovery of heavy oil.

### 3.2.2. High-Temperature Stability Performance

During the steam injection process, the temperature of steam injection is normally more than 260 °C, so the plugging agent needs to maintain long-term stability at high temperature. For this reason, the thermal stability tests for the high-temperature plugging agent, HTP, and quartz sand consolidated body were carried out at 260, 280, and 300 °C for a long period (test conditions: quartz sand proportion 70%; the constant temperature time was 60, 120, and 180 d), and the results are shown in Figure 9.

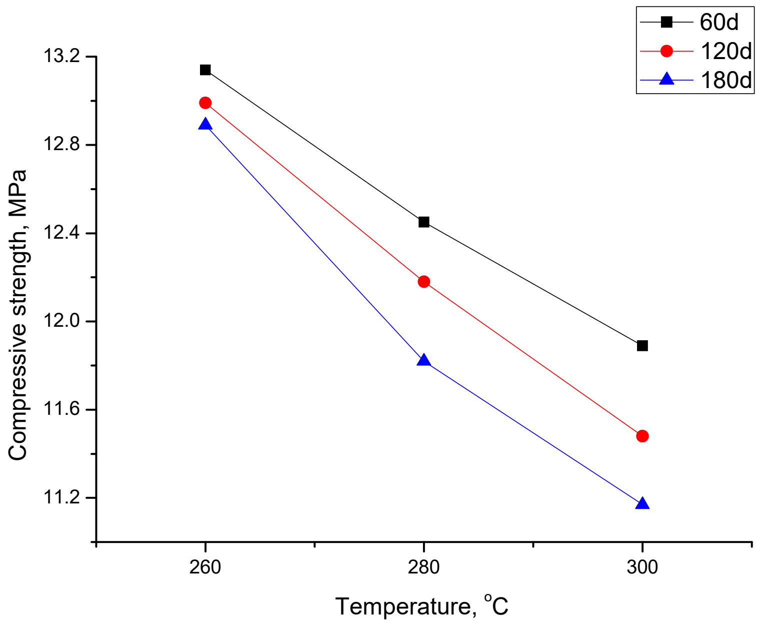


**Figure 9.** Compressive strength of HTP at different time and temperature levels.

It can be seen from Figure 9 that at 260–300 °C, the consolidated body formed by HTP and quartz sand still had a high compressive strength after a long time of constant temperature aging. With the increase of temperature, the compressive strength decreased to a certain extent, but the decrease was small. After being placed under 300 °C conditions for 180 days, the compressive strength was still higher than 12 MPa. This means that HTP has good temperature resistance, which can reach more than 300 °C.

### 3.2.3. High-Temperature Plugging Performance

Using the high-temperature and high-pressure coreflooding apparatus, the plugging effect of the high-temperature plugging agent, HTP, on sandpacks with different permeability was analyzed through displacement experiments. Considering that the formation permeability had been greatly increased because of steam channeling during steam injection, the core of high permeability was made by sandpacking. The sandpack was vacuumized first, the water-phase permeability $K_{w1}$ was measured, and then HTP was injected until it reached the pore volume of the sandpack. Then the inlet and outlet at both ends of the sandpack were closed, and the water phase permeability $K_{w2}$ of the sandpack was measured at the specified temperature 273 °C for 8 h. The pressure resistance intensity was recorded, and the plugging ratio for water phase and breakthrough pressure gradient was calculated. The results are shown in Table 3.

**Table 3.** High-temperature plugging results for sandpacks with different permeability.

| Case No. | $K_{w1}$, mD | T, °C | $K_{w2}$, mD | Plugging Ratio, % | Breakthrough Pressure Gradient, MPa/m |
|---|---|---|---|---|---|
| 1 | 13,524 | 220 | 53.45 | 99.60 | 28.33 |
| 2 | 15,232 | 240 | 62.13 | 99.59 | 28.00 |
| 3 | 16,110 | 260 | 65.56 | 99.59 | 26.66 |
| 4 | 11,154 | 280 | 55.12 | 99.51 | 30.33 |
| 5 | 12,565 | 300 | 57.89 | 99.54 | 27.33 |

As can be seen from Table 3, HTP has a good plugging effect on the high permeability core. The plugging ratio of the core with high permeability was higher than 99.5% and the pressure gradient was greater than 28 MPa/m after being pressed into the core at 220–300 °C for 8 h. The steam injection pressure of Fengcheng oilfield in Xinjiang was mostly less than 15.0 MPa. HTD can therefore meet the requirements of high-temperature plugging of heavy oil and inhibiting steam channeling.

### *3.3. Field Application Performance*

Block Z18, which is currently developed by vertical-well CSS, is the main heavy oil contributor to Xinjiang oilfield. The formation includes five payzones, while the steam conformance is increasingly challenged by reservoir heterogeneity when CSS continues, and well-to-well steam channeling is a common phenomenon, which severely impacts the CSS performance. Taking a typical well A as an example, it is shown in Figure 10 that the steam proportion was 25.87% and 41.8% in the upper two zones, and in the lower zones, it was 8.93–11.2% at the third cycle. However, the steam preferential flow became evident with the cycles, and the steam proportion of lower ones constantly declined. At the seventh cycle, the steam proportion of the second zone has reached 53% and the fifth zone did not absorb steam.

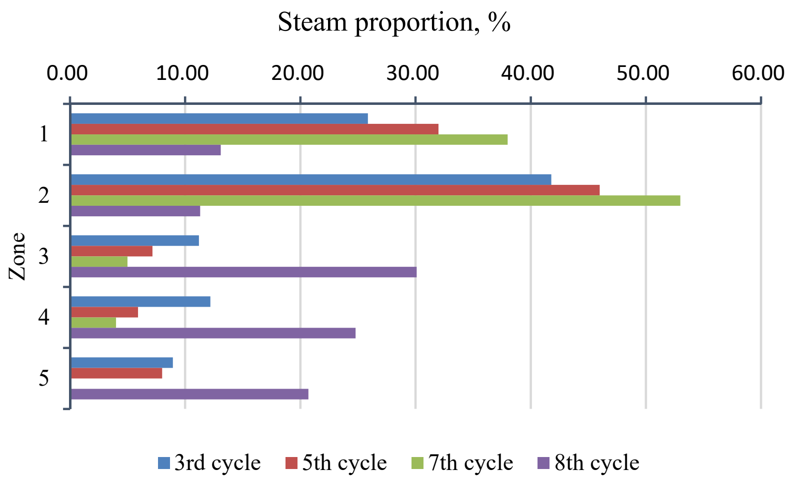


**Figure 10.** Steam proportion profile at different cycles.

During the injection strategies determination of the plugging agent, the literature proposed that the multi-stage plugging method can effectively solve the problem of steam channeling, which provided guidance to the field injection process [25]. At the eigth cycle, the optimized plugging agent, HTP, was injected into the formation, and the steam profile after that was encouragingly improved [3]. The steam proportion of the upper two zones declined to 13.1% and 11.3, and most steam entered into the lower zones, contributing to a steam proportion of 20.7% to 30.1% for each zone. Due to the steam profile improvement, the cyclic oil production was 217.6% that of the seventh cycle. It is predicted that the incremental oil recovery factor could reach 3–5% on the basis of 18.8% by conventional commingling steam injection.

## 4. Conclusions

Apart from the reservoir sedimental heterogeneity, high-speed and high-pressure steam injection induced formation dilation and mini-fractures are the main factors in steam channeling during the CSS process.

The real super-heavy oil reservoir core samples were acquired to carry out the three-tube coreflooding experiments, which indicates that the formation heterogeneity deteriorates in the long-term steam injection process, and the dynamic permeability ratio (max/min) is much higher than the initial condition. Thus, the dynamic change in permeability should be considered when devising steam injection strategies.

Due to the harsh pressure and temperature conditions in the steam injection periods of CSS, the plugging agent is a much stronger and more practical candidate than gas foam or FCD/ICD to improve the steam conformance, particularly after severe steam channeling in multi-cycles of CSS.

The optimized plugging agent, HTP, could resist high temperatures over 260 °C and its compressive strength was 13.14 MPa, which is higher than maximal steam injection pressure in the Xinjiang oilfield. The field test validated its profile improvement feasibility, showing significant potential for similar CSS reservoirs.

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## Nomenclature

| | |
|---|---|
| CSS | Cyclic steam stimulation |
| CWE | Cold water equivalent |
| O/W | Oil/water |
| FCD/ICD | Flow control device/Inflow control device |
| TDS | Total dissolved solids |
| HTHP | High-temperature–high-pressure |
| HT | High-temperature |
| HTP, HTE, HTF, and HTG | Names of the plugging agents |

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