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Experimental study on horizontal-well multi-thermal fluid stimulation process in offshore heavy oil reservoirs

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Abstract
The development of offshore heavy oil is sensitive and complex, which is limited by factors such as platform space, economy, pollution and security, so conventional thermal recovery techniques such as cyclic steam stimulation and steam flooding have difficulty in achieving favorable development effect for offshore heavy oil reservoirs. Horizontal-well multi-thermal fluid stimulation (HW-MTFS) process is a relatively new thermal recovery technique, which combines the multiple advantages of gas injection, horizontal well and thermal recovery process. In this paper, the HW-MTFS physical model was firstly designed. Thereafter, the influences of different factors on steam absorption along horizontal wellbore were studied by sand-packed model experiments. Finally, the development performance of horizontal-well cyclic steam stimulation (HW-CSS) process and horizontal-well multi-thermal fluid stimulation process was compared by two groups of physical experiments. The results indicate that different injection factors significantly influenced the steam absorption along horizontal wellbore. Compared with steam injection, the multi-thermal fluid injection could effectively improve the steam absorption along horizontal wellbore. The HW-MTFS process had a higher oil rate and production, and the recovery of HW-MTFS process was 42% higher than that of HW-CSS in three cycles.

Keywords Offshore heavy oil · Cyclic steam stimulation · Multi-thermal fluid · Thermal recovery · Development performance

List of symbols

ρ	Oil density, kg/m^3
g	Acceleration of gravity, m/s^2
L	Length, m
w	Width, m
h	Thickness, m
Φ	Porosity, f
S_o	Oil saturation, f
K	Permeability, μm^2
μ	Oil viscosity, Pa s
α	Thermal diffusivity, m^2/s
γ	Apparent velocity, m/s
X	Steam quality, %
L_v	Steam latent heat, J/kg
C_w	Specific heat capacity of water, J/(kg K)
ΔT	Temperature variation, K

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Introduction

With the development of global economy and the exhaustion of onshore oil and gas resources, offshore oil and gas resources have recently attracted more and more attention (Sheikholeslami et al. 2017; Sheikholeslami and Rokni 2017; Sheikholeslami and Shehzad 2017). Offshore heavy oil as an important part of offshore resources has played an increasingly important role in industry (Yang et al. 2014). Heavy oil resources are abundant in the Bohai Bay of China which has approximately 2.3 billion tons of heavy oil resources (Gu et al. 2007). For heavy oil, viscosity is the key factor determining the development regimes. Heavy oil with the viscosity of less than 350 mPa•s can be effectively developed by water flooding as well as a series of techniques such as chemical flooding, well pattern thickening, and so on (Ji 2012). However, just limited reserves could be developed by the cold recovery technology for heavy oil with the viscosity greater than 350 mPa s; at this time, steam injection will show its unique advantages and high recovery (Fengrui et al. 2017a, b, c; Fan et al. 2016).

In the process of conventional thermal recovery such as cyclic steam stimulation, steam flooding and steam-assisted gravity drainage, steam as heat carrier is injected to heat formation, so the principal mechanisms of thermal recovery consist of oil thermal expansion, viscosity reduction and steam distillation. However, two significant problems exist in the steam injection process for developing heavy oil reservoirs. One is known as steam override caused by gravity segregation between steam and oil/water. The other is known as steam channeling resulting from the formation heterogeneity. Many studies have shown that the efficiency of steam injection can be improved by using additives such as CO_2, N_2, flue gas, air and solvent. Stone and Malcolm (1985) carried out a 1.5-m-diameter physical simulator packed with Athabasca oil sand to discuss the merits of steam–CO_2 injection process relative to steam injection alone. Bagci and Gumrah (2004) used 1D and 3D experiments to study the effect of simultaneous injection of CO_2 and CH_4 together with steam to develop the Kozluca heavy oil. The results indicated that gas–steam injection was a promising technique and gas–steam ratio was a significant factor on the heavy oil recovery. Canbolat et al. (2002) indicated that CO_2 accumulated at the top of reservoir and provided a thermal and pressure insulation to limit the front spreading rate at the corners of steam chamber. Li et al. (2011) asserted that in the process of CSS, CO_2 injection could increase the displacement efficiency. Zhang et al. (2014) carried out 2D physical experiments to study the feasibility of CO_2 injection in the SAGD process. The results indicated that injected CO_2 had dual effect of noncondensable gas and solvent during SAGD process in extra-heavy oil reservoirs, CO_2 injection not only improved the volume of steam chamber, but also increased the oil rate. Wang et al. (2018a) carried out the high-temperature PVT tests beyond 150 °C and coreflood experiments; it was found that CO_2 injection could effectively reduce the density and viscosity of extra-heavy oil under high-temperature and high-pressure conditions; CO_2 was a good potential agent to improve the development performance of SAGD process for developing extra-heavy oil. Harding et al. (1987) demonstrated the relative importance of CO_2 and N_2 injection during the steam flooding process through the numerical model. Du et al. (2013) carried out the N_2-assisted CSS experiments. The results indicated that N_2 injection reduced heat loss and increased the heating radius of steam in the CSS process.

Many studies also have pointed out that flue gas injection can obviously improve the development performance of thermal recovery. Nasr et al. (1987) indicated that the addition of flue gas to steam obviously improved both oil rate and ultimate recovery of bitumen compared with that obtained by steam-alone. Alnoaimi indicated that injecting noncondensable gas in steam flooding process not only increased the ultimate recovery slightly over steam-alone injection, but also accelerated oil production at early stage of steam flooding process (Alnoaimi 2010). Wang et al. also indicated that the addition of flue gas to steam could significantly improve the development performance of heavy oil compared with steam-alone injection (Wang et al. 2017b). Srivastava et al. (1997) investigated the most suitable gas injection strategy through coreflood tests with Senlac heavy oil. Srivastava et al. also carried out PVT tests and coreflood experiments to assess the suitability and effectiveness of three injection gases which included a flue gas (15 mol% CO_2 in N_2), a produced gas (15 mol% CO_2 in CH_4) and pure CO_2 for developing Senlac heavy oil. The results indicated that CO_2 was the best recovery agent, gas injection combined two competing mechanisms such as free-gas mechanism and solubilization mechanism, the latter predominated in the process of pure CO_2 injection, but in the flue gas and produced gas cases, the free-gas mechanism was more important (Srivastava et al. 1999). Liu et al. (2001) carried out the coreflood experiments with flue gas as an additive in the process of steam flooding; it was found that flue gas injection decreased the steam partial pressure and increased the steam quality, and then enhanced the steam distillation effect. Li et al. (2017) investigated the interface properties and viscosity reduction of heavy oil injected with flue gas by physical experiments, and it was found that flue gas injection reduced the viscosity and interfacial tension of heavy oil and improved the development performance of steam flooding. Air injection is also a potential method to improve the development performance of steam injection. After injecting air into the reservoir, O_2 will be oxidized with crude oil to form oxides of carbon. The heat produced by oxidation can increase the reservoir temperature and promote the evaporation of light components (Wang et al. 2017a; Wang et al. 2018b, c). Therefore, the gas which acts as direct displacement is not the air, but CO and CO_2 produced in the reservoir, and the flue gas composed of N_2 and light hydrocarbon (Yu 2013).

Multi-thermal fluid is a relatively new injection agent. The generation of multi-thermal fluid is based on the combustion and jetting mechanisms of rocket engine. In the combustion process, diesel oil (crude oil or natural gas) and high-pressure air are injected into the combustion cell, and water is injected at high-pressure condition (Ren 2013). Multi-thermal fluid mainly includes steam, CO_2, N_2, CH_4, CO, etc., and the steam of multi-thermal fluid is always in the superheated condition. Compared with conventional steam, multi-thermal fluid has higher temperature and enthalpy by the distinctive generation method. In 2009, MTFS process was firstly introduced into Shengli Oilfield of China and a typical CSS well, namely the GDN5-604 well, implemented the MTFS pilot tests. Half a year later, the comprehensive water cut decreased from 94.3 to 67.1% and the oil rate increased from 2.8 t/d to 10.1 t/d, with a cumulative oil increment of 1009 t (Liu et al. 2001). In 2010, MTFS process was introduced into Bohai Oilfield of China to develop the NB35-2S heavy oil block. The oil production was significantly improved after six stimulation cycles in four horizontal wells (Yu et al. 2014).

The recoverable reserves of vertical well for developing heavy oil reservoirs are lower, and the economic benefit of them is poorer compared with that of horizontal well. The utilization of horizontal well in the CSS process can increase the drainage area, reduce steam injection pressure and enhance oil recovery. In 1978, Esso Resources Company invested in establishment of the first horizontal well for thermal recovery with a horizontal section of 300 m in the Albert of Canada, and the initial effect of the test was satisfactory. In 1992, two horizontal wells were drilled to conduct the CSS pilot tests in Midway Sunset Oilfield. After two stimulation cycles, steam injection and oil rate were improved by 20–50% compared with vertical well, and oil production increased up to 3493 m^3 (Liu 1998; Ling and Huang 1996). Coats et al. (1984) proposed a physical simulation method and successfully simulated horizontal-well cyclic steam stimulation which increased crude oil production. Rial (1984) established a 3D geological model of Kern River Oilfield in California by numerical simulation and compared the effect of steam injection in vertical and horizontal wells for 15 a. The results show that horizontal well recovery was up to 71% due to its advantages of high sweep efficiency and large heat radius, so horizontal well was more suitable for thermal recovery of heavy oil reservoirs. Zhao put forward the economic and technical policy boundaries for the geological design of horizontal wells during thermal recovery in heavy oil reservoirs under the oil price and technical conditions through statistical analysis, numerical simulation and analytical method based on the actual data of eight blocks in Cao-20, Caonan, Shanjiasi and Gudao reservoirs of Shengli Oilfield (Zhao 2008). Hou et al. (2016) established an optimization method to solve the parametric design problem for CSS by horizontal well in heavy oil reservoirs. Zhang and Jiang (2013) simulated Du84 heavy oil reservoir and optimized injection steam volume, soaking time and well spacing of horizontal well during CSS process.

In recent years, many studies have been done on the MTFS process, but most of them mainly focus on the pilot tests and technological process. Meanwhile, the role of horizontal well in thermal recovery is becoming more and more important, but the inhomogeneity of steam absorption along horizontal wellbore is a prominent problem. Both the friction loss along horizontal wellbore and the heterogeneity of horizontal section lead to the inhomogeneity of steam absorption, and the development effect of horizontal well becomes more and more serious with the increase in the horizontal section length.

In order to make full use of the advantages of horizontal well and multi-thermal fluid, the paper further studied the horizontal-well multi-thermal fluid stimulation process by physical experiments. In this paper, a HW-MTFS physical model was firstly designed to study the influence of different factors on steam absorption along horizontal wellbore and compare the development performance of different stimulations by horizontal well. All the study results could provide theoretical support for the thermal recovery in offshore heavy oil reservoirs.

Experiments

Experimental material

The crude oil was collected from the NB35-2 block of Bohai Oilfield in China, which is a heavy oil reservoir with the formation depth of 1100 m and original temperature of 56 °C. The crude oil was cleaned by using a centrifuge to remove any sand particles and brine. Figure 1 displays the viscosity–temperature curve. Density and viscosity of the crude oil were, respectively, measured to be 0.956 g/cm^3 at 20 °C by DMA 4200 M densitometer (Anton Paar, Austria) and 2907 mPa•s at 50 °C by MCR302 rheometer (Anton Paar, Austria). The formation water salinity was between 7200 mg/L and 7500 mg/L, with an average of 7300 mg/L, and the formation water belonged to Na_2SO_4 type. The experimental water was deionized water. The experimental packing sand is quartz sand.

Experimental design

Similarity theory is the basic theory guiding physical experiment. In order to reflect the real reservoir, the similarity theory was applied to design the physical model. In the

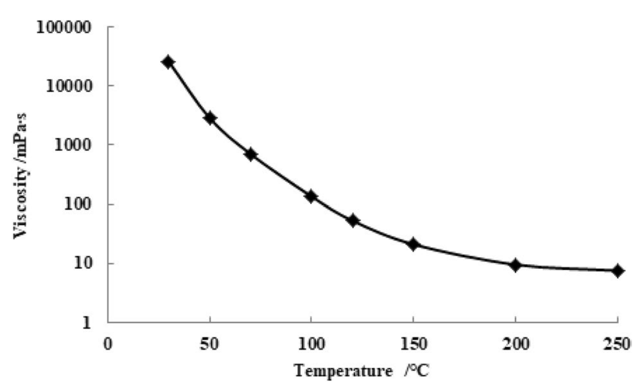


Fig. 1 Crude oil viscosity–temperature curve

Table 1 Parameters of similarity theory for physical experiment

Similarity criteria	Physical meaning	Parameter
L/w, L/h	Physical dimension	Length
$K\Delta\rho g/\gamma\mu$	The ratio of gravity to viscous force	Permeability
Φ	Porosity	Porosity
S_o	Oil saturation	Oil saturation
$\alpha/\gamma L$	The ratio of heat conduction to convection	Injection rate
$XL_v/C_w\Delta T$	The ratio of heat loss to heat injected	Steam quality

Table 2 Parameters conversion between reservoir and experiment model

Parameters	Reservoir	Experimental model
Wellbore diameter	0.2 m	1 cm
Thickness/width	40 m	20 cm
Length	180 m	90 cm
Porosity	28.7%	28.7%
Initial oil saturation	89.0%	89.0%
Permeability	2.365 μm^2	473 μm^2
Steam temperature	250 °C	250 °C
Initial temperature	56 °C	56 °C
Steam quality	55.0%	55.0%
Steam injection rate	336 m^3/d	100 mL/min

experiments, the parameters including the fluid properties, rock thermal properties and pressure temperature conditions of the physical model were considered to be the same as those of real reservoir. The similarity theory of Pujol and Boberg model was used in the experiments which is shown in Table 1 (Pujol and Boberg 1972; Tian 2006). The specific experimental parameters are shown in Table 2.

Experimental apparatus

The experimental apparatus is shown in Fig. 2 which mainly consists of four parts, namely injection system, variable mass flow simulator of horizontal wellbore, data acquisition system and output system. Injection system mainly consists

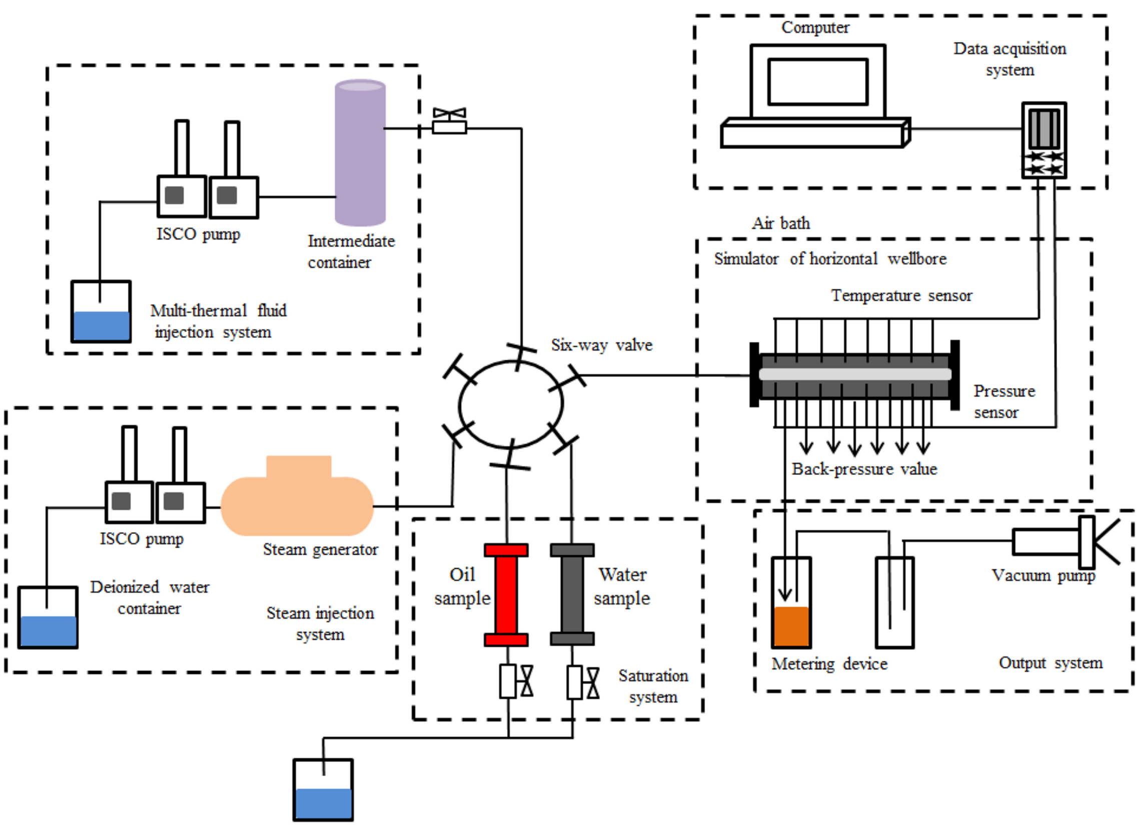


Fig. 2 Schematic apparatus of steam absorption along horizontal wellbore during multi-thermal fluid injection

of ISCO pump, intermediate container and steam generator. The maximum output steam temperature and pressure of steam generator were 350 °C and 30 MPa, respectively. Data acquisition system was used to real-timely record temperature and pressure data through temperature and pressure sensors. The main function of the output system which included back-pressure valve, high-pressure pipeline and gas–liquid-collecting bottle was to accurately measure the real-time production of outlet (Dong and Huang 2002; Jin et al. 2017).

Variable mass flow simulator of horizontal wellbore was the main body of experimental model. As shown in Fig. 3, the simulator mainly included 11 parts such as (1) model cylinder, (2) flange plate, (3) simulation wellbore, (4) packing sand, (5) adapter, (6) back-pressure valve, (7) temperature sensor, (8) pressure sensor, (9) high-pressure pipeline, (10) tubing injection switch valve and (11) casing injection switch valve. Figure 4 shows the physical diagram of variable mass flow simulator of horizontal wellbore.

The model cylinder was cylindrical whose size was 200 mm × 900 mm, and its maximum operating pressure and temperature were 35 MPa and 350 °C, respectively. Sixty temperature sensor threaded holes, ten pressure sensor threaded holes and 36 drainage threaded holes were distributed equidistantly on the cylinder wall. The simulation wellbore horizontally passed through the enclosed space of model cylinder, and the two ends of the simulation wellbore passed through the earholes in the middle of the flanges and formed a seal between the earholes. The diameter of simulation wellbore was 8 mm. The perforation number per unit length of simulation wellbore was 400 n/m. The packing sand was filled between the model cylinder and simulation wellbore. The high-pressure pipelines were used to simulate the injection pipelines. The back-pressure valves were connected with the drainage threaded holes on the model cylinder through the pipelines, so that the liquid in the model cylinder could be discharged out through the back-pressure valves, and the drainage pressure could be controlled by adjusting the pressure of back-pressure valves. Temperature and pressure sensors in the model cylinder were connected with data acquisition device to real-timely record the corresponding data.

Experimental procedure of steam absorption along horizontal wellbore

The experimental procedure includes the following steps: sand filling, gas-tightness test, water saturating, oil saturating and stimulation experiments.

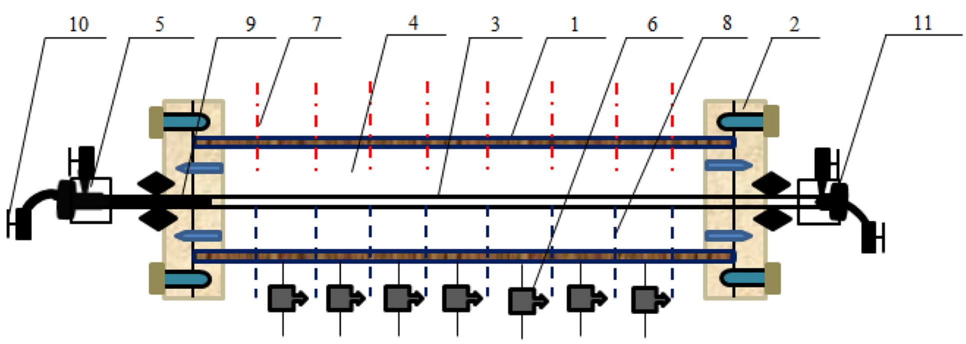


Fig. 3 Schematic diagram of variable mass flow simulator of horizontal wellbore

Fig. 4 Physical diagram of variable mass flow simulator of horizontal wellbore

(1) The experimental device such as simulation wellbore, temperature and pressure sensors, high-pressure pipelines were firstly fixed on the designed position. (2) The model cylinder was filled with quartz sands and equipped into the experimental system. (3) High-pressure N_2 was injected into the experimental system to carry out leak test. (4) The model was first saturated with water, after which a heated heavy oil sample was pressed into the model by an ISCO pump, thereby displacing the residual water through its pores and to saturate oil. During the process, about 7195 ml heavy oil was injected to obtain 89.0% initial oil saturation in the model. (5) Model cylinder was placed in the constant-temperature oven whose temperature was controlled at 56 °C for over 36 h until reaching isothermal conditions in the experimental model. (6) Different experiments were carried out; in the process of experiments, steam or multi-thermal fluid was injected into the model at a constant speed; meanwhile, the temperature and pressure along the horizontal wellbore were real-timely recorded.

Experimental scheme of steam absorption along horizontal wellbore

During the experiments, the high-pressure pipelines were used as the injection steam tubes. Different injection mode experiments were simulated by changing the position of high-pressure pipelines in the model cylinder. Different injection steam rate experiments were simulated by changing the injection rate. Different reservoir condition (homogeneity or heterogeneity) experiments were simulated by changing the permeability of model cylinder. Different injection fluid experiments were simulated by changing the injection fluids (steam or multi-thermal fluid). Different well completion technique experiments were stimulated by changing the perforation mode.

The specific experimental schemes were designed as follows to analyze the steam absorption along horizontal wellbore in heavy oil reservoir under different conditions.

(1) Different injection rates: 70 mL/min, 110 mL/min and 150 mL/min.
(2) Different injection fluids: steam, multi-thermal fluid.
(3) Different injection modes: heel injection, toe injection, middle injection and two-end injection.
(4) Different reservoir conditions: homogeneity reservoir, heterogeneity reservoir (the 1/3 middle part was high-permeability/low-permeability zone).
(5) Different well completion techniques: perforated completion, slotted completion.

In the process of experiments, the average porosity and permeability were 28.7% and 473 D, respectively. The initial oil saturation was 89%. The basic injection rate, injection temperature, injection mode and well completion technique were 110 mL/min, 250 °C, heel injection and perforated completion, respectively.

Stimulation experiment procedure

For the stimulation experiments, the experimental materials, design, apparatus and procedure were similar to the experiments of steam absorption along horizontal wellbore shown in Fig. 2. The experimental procedure mainly included sand filling, leak test, water saturating and oil saturating. After that, the stimulation experiments were carried out. Three stimulation cycles were conducted in the process of experiments. During each cycle, firstly, filled the sand pack with steam/multi-thermal fluid at 200 mL/min for 10 min, then soaked for 2 min, finally produced for 100 min.

The results and discussion of experiments

Variation characteristics of steam absorption along horizontal wellbore under different injection rates

The temperature and pressure data recorded in the data acquisition device were extracted, and the characteristic curves of pressure drop and temperature along horizontal wellbore with different steam injection rates are drawn as shown in Figs. 5 and 6.

As can be seen from the above figures, no matter how high the injection rate was, both pressure and temperature gradually decreased along the horizontal wellbore because of friction loss. However, the loss of pressure and temperature along the horizontal wellbore decreased smoothly with the increase in steam injection rate. When the steam injection rate was 150 mL/min, the pressure decreased from 10.5 to 8.6 MPa and decreased by 18.1% from heel to toe

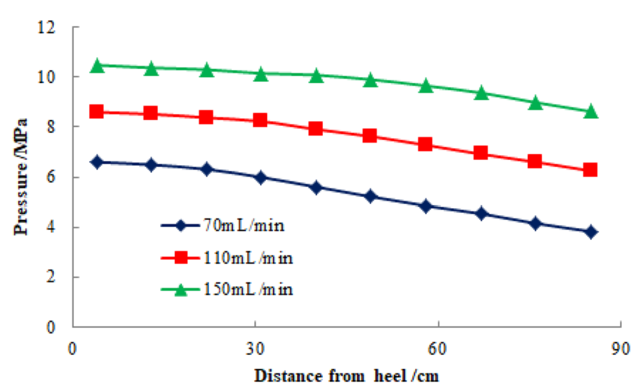


Fig. 5 Characteristic curves of pressure along horizontal wellbore under different steam injection rates

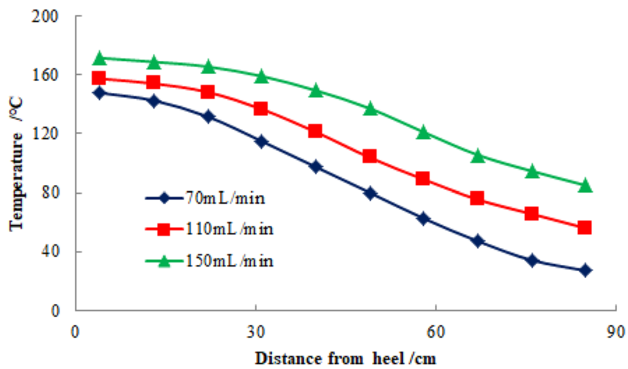


Fig. 6 Characteristic curves of temperature along horizontal wellbore under different steam injection rates

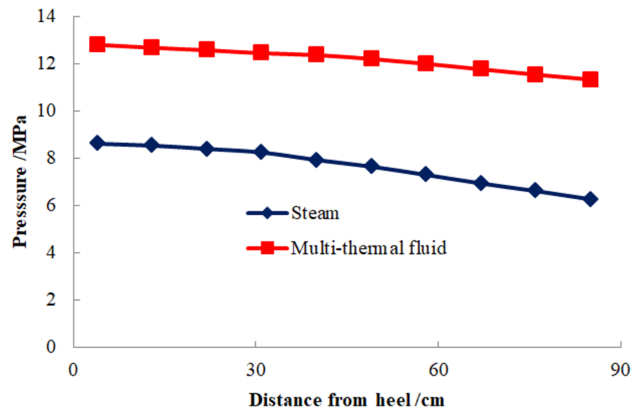


Fig. 7 Characteristic curves of pressure along horizontal wellbore under different injection

of horizontal wellbore and the temperature decreased by 50.5% from 214.6 °C. The pressure decreased by 42.4% and 27.3%, respectively, at 70 mL/min and 110 mL/min of steam injection rate, and the temperature decreased by 81.7% and 64.5%, respectively.

The steam injection rate had a great influence on the total injection heat of the formation when other parameters kept unchanged. The larger the steam injection rate was, the greater the total injection heat was. With the increase in steam injection rate, the average steam absorption rate per unit length of horizontal wellbore decreased slightly; meanwhile, considering the limited steam absorption capacity of the reservoir, therefore, the inhomogeneous characteristic of steam absorption along horizontal wellbore in reservoir could been improved by higher injection rate.

Variation characteristics of steam absorption along horizontal wellbore under different injection fluids

As shown in Figs. 7 and 8, the characteristic curves of pressure drop and temperature along horizontal wellbore with different injection fluids are drawn.

From Figs. 7 and 8, it can be seen that compared with injection steam, the advantages of injection of multi-thermal fluid were mainly manifested in the reduction in heat loss, lower pressure drop, longer heat length and effective improvement of injection effect. When the injection rate was same, the pressure decreased by 11.6% from 12.8 MPa and the temperature decreased from 155.3 to 73.8 °C and decreased by 52.5% with multi-thermal fluid injection from heel to toe of horizontal wellbore. However, the pressure and temperature decreased by 27.3% and 64.9% from 8.6 MPa and 158.7 °C, respectively, when the injection fluid was steam.

This was mainly due to the fact that noncondensable gas in multi-thermal fluid could improve the thermophysical properties of fluids. Compared with injection steam, the density and viscosity of fluids were lower and the loss of pressure drop in wellbore was smaller after injecting multi-thermal fluid. In addition, N_2 had good thermal insulation performance, which could reduce the heat loss between fluids and wellbore/formation.

Variation characteristics of steam absorption along horizontal wellbore under different injection modes

Figure 9 shows the variation characteristics of pressure drop along horizontal wellbore with different steam injection modes. Figure 10 shows the variation characteristics of temperature along horizontal wellbore with different steam injection modes.

As shown in the above figures, different injection modes obviously influenced the distribution of pressure and temperature along horizontal wellbore. The highest pressure appeared at the injection steam point and decreased

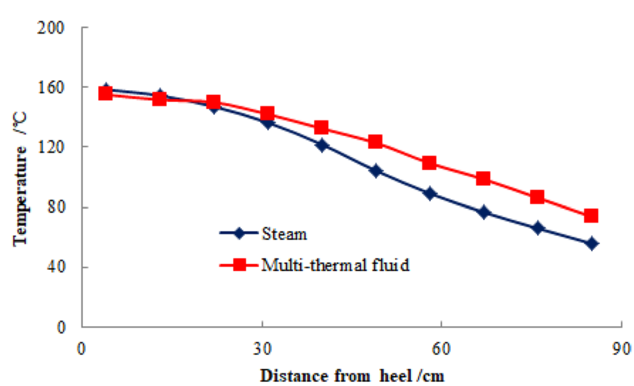


Fig. 8 Characteristic curves of temperature along horizontal wellbore under different injection fluids

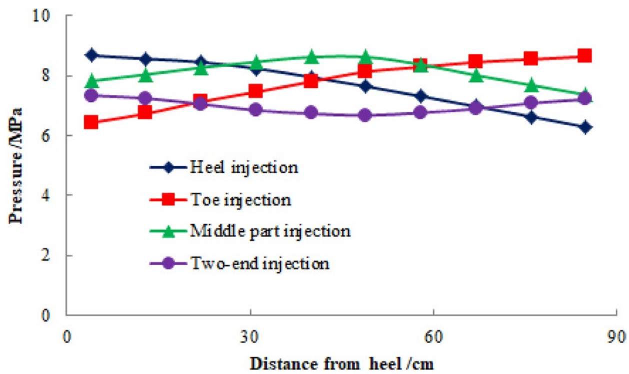


Fig. 9 Characteristic curves of pressure along horizontal wellbore under different steam injection modes

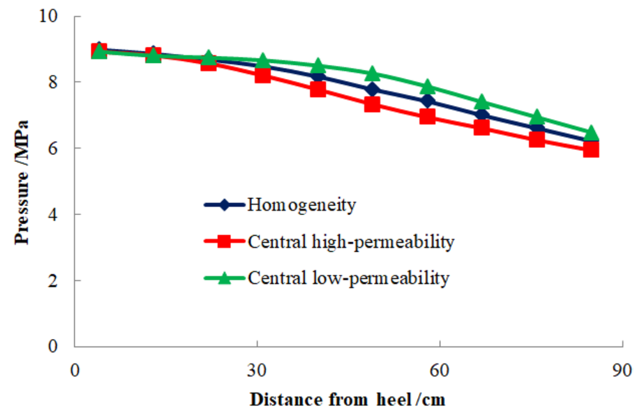


Fig. 11 Characteristic curves of pressure along horizontal wellbore under different reservoir conditions

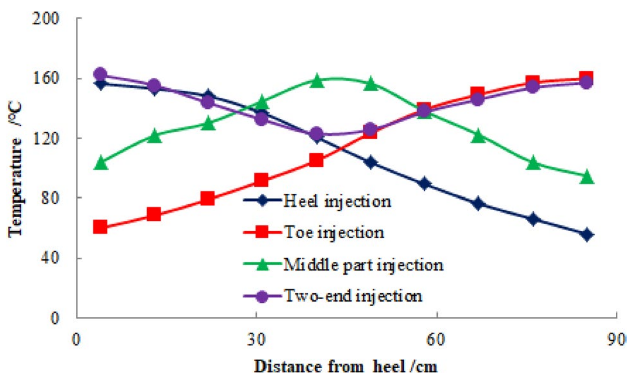


Fig. 10 Characteristic curves of temperature along horizontal wellbore under different steam injection modes

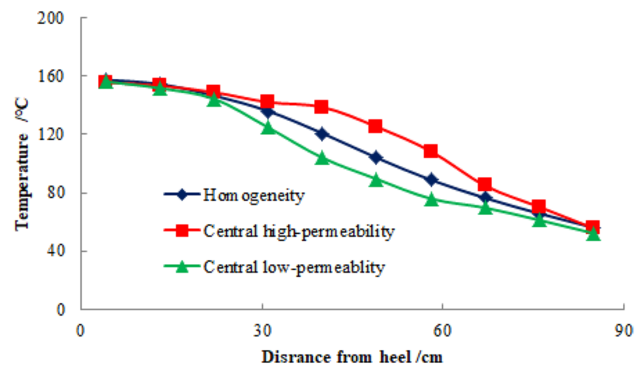


Fig. 12 Characteristic curves of temperature along horizontal wellbore under different reservoir conditions

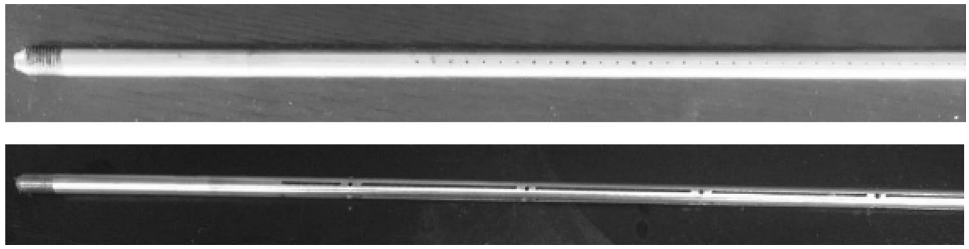
gradually as away from the injection point due to pressure loss. The thermal-affected part along the horizontal wellbore was also closed related to the injection mode. The heel of the wellbore was obviously effective when the injection steam position was at the heel end, and the injection mode at the toe, middle part and two ends of the wellbore had the same rule. In the process of actual production, the steam absorption profile along the horizontal wellbore could be effectively balanced by periodically changing the injection position, so that the horizontal wellbore could be uniformly heated to improve the development performance. In addition, the pressure loss along the horizontal wellbore was reduced and the heating range of the formation along the horizontal wellbore was increased by the two-end injection mode compared with the single-end injection mode. Therefore, the heating effect along the horizontal wellbore could be effectively improved by concentric or parallel two-pipe section injection steam technique in the production process of actual reservoir.

Variation characteristics of steam absorption along horizontal wellbore under different reservoir conditions

Figures 11 and 12 display the variation characteristics of pressure drop and temperature along horizontal wellbore with different reservoir conditions.

As can be seen from the above figures, the effect of injection steam along horizontal wellbore was greatly affected by the permeability of the formation. It was because the permeability directly affected the seepage ability of injected fluids in formation. The higher the formation permeability along the horizontal wellbore was, the larger the steam absorption capacity and the better the heating effect were. If the toe of the horizontal well was in the high-permeability zone, the increase in steam absorption could effectively balance the inhomogeneity of the steam absorption profile in formation, but if the injection point was in the high-permeability zone, it might aggravate the inhomogeneity of the steam absorption profile along the horizontal wellbore.

Fig. 13 Model of perforation well and slotted well



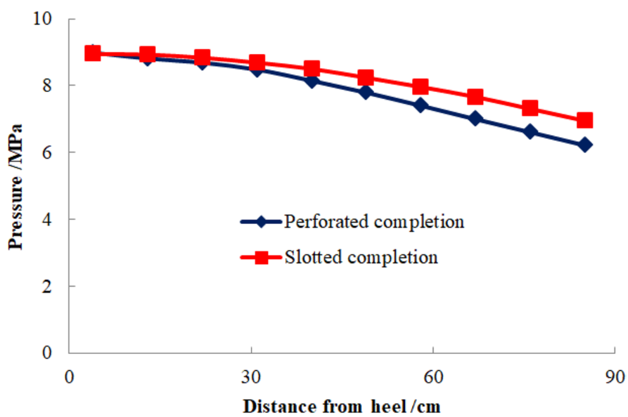


Fig. 14 Characteristic curves of pressure along horizontal wellbore under different well completion techniques

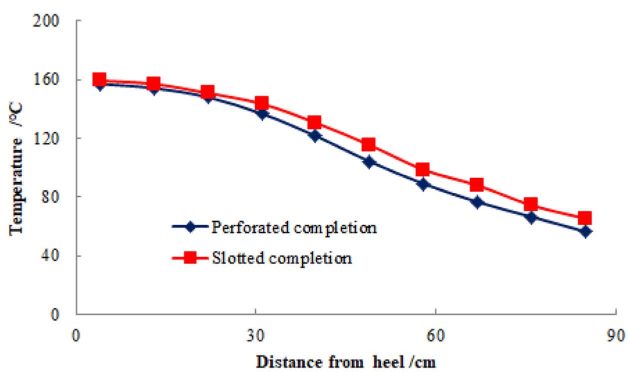


Fig. 15 Characteristic curves of temperature along horizontal wellbore under different well completion techniques

Variation characteristics of steam absorption along horizontal wellbore under different well completion techniques

Figure 13 displays the model of perforation well and slotted well. As shown in Figs. 14 and 15, the characteristic curves of pressure drop and temperature along horizontal wellbore with different well completion techniques are drawn.

From Figs. 14 and 15, it can be seen that compared with perforated completion, slotted completion could effectively reduce pressure loss along the horizontal wellbore, expand heating range and balance heating effect of reservoir.

Table 3 Basic parameters of stimulation experiments

Case	Porosity (%)	Permeability (D)	Initial oil saturation (%)	Injection temperature (°C)
CSS	28.3	471	88.7	250
HW-MTFS	28.9	466	89.1	250

Development performance of different stimulation experiments

Table 3 displays the basic parameters of two groups of stimulation experiments.

Figure 16 shows the oil rate and cumulative oil production of two groups of stimulation experiments. As shown in Fig. 16, the oil rate of HW-MTFS process was higher than that of CSS process in each cycle. As can be seen from Table 4, the average oil rate per cycle in CSS experiment was 2.55 mL/min, 2.07 mL/min and 1.5 mL/min, respectively, and the corresponding cumulative oil production was 254.5 mL, 207.1 mL and 149.7 mL. The average oil rate per cycle in HW-MTFS experiment was 3.21 mL/min, 2.98 mL/min and 2.45 mL/min, respectively, and the corresponding cumulative oil production was 320.9 mL, 298.1 mL and 244.7 mL. The cumulative recovery of CSS and HW-MTFS after three cycles was 8.49% and 12.06%, respectively. The recovery of three HW-MTFS cycles was 42% higher than that of CSS process. From Fig. 16, it can also be seen that with the increase in stimulation cycle, the periodic recovery of CSS decreased greatly, but that of HW-MTFS decreased relatively smoothly. It means that more oil could be produced by HW-MTFS process in limited time, it is very important for developing offshore heavy oil. The reason might be that in the process of CSS, with the increase in injection steam, friction loss and heat loss increased gradually that enhanced the inhomogeneity of steam absorption profile and obviously reduced the periodic oil production. However, during HW-MTFS process, the generated gas such as CO_2, N_2 and CH_4 effectively improved the steam absorption profile and development performance.

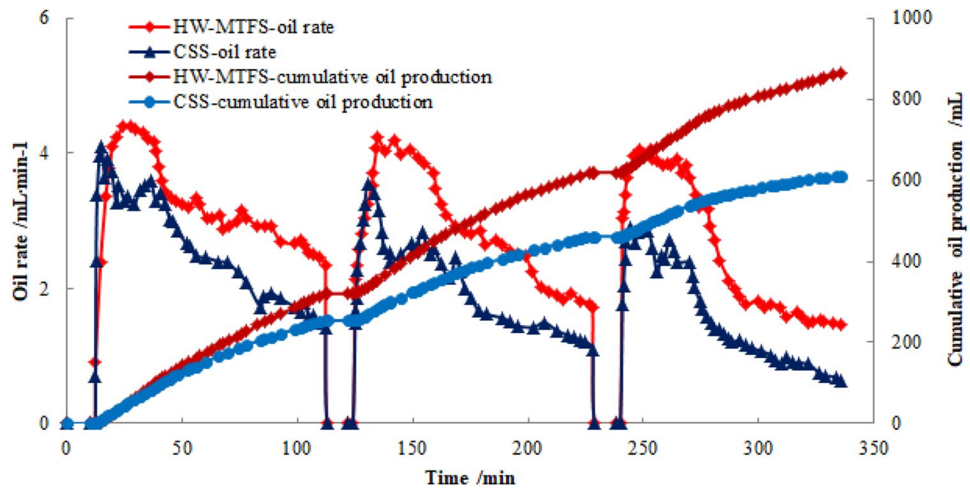


Fig. 16 Oil production rate and cumulative oil production of the experiments

Table 4 Development data of the huff-puff experiments

Experiment	Cycle	Average oil production rate (mL min^{-1})	Cycle oil production (mL)	Cycle recovery (%)	Recovery reduction extent (%)
CSS	1	2.55	254.5	3.54	–
	2	2.07	207.1	2.87	18.67
	3	1.5	149.7	2.08	27.64
HW-MTFS	1	3.21	320.9	4.48	–
	2	2.98	298.1	4.16	7.12
	3	2.45	244.7	3.42	17.87

In summary, compared with CSS, HW-MTFS is a more effective EOR method for developing offshore heavy oil. It combines the multiple advantages of gas injection, horizontal well and thermal recovery processes. In the process of HW-MTFS, with the exception of the conventional mechanisms of injection steam such as reducing oil viscosity, heat expansion, steam distillation and improving relative permeability, it also has other EOR mechanisms. (1) Horizontal wellbore increases the drainage oil area and decreases the production pressure difference. (2) Generated CO_2 has high solubility in heavy oil, the dissolution of CO_2 can increase the oil volume and flowing capacity. (3) The dissolution of CO_2 can further decrease the oil viscosity and improve the oil relative permeability. (4) The dissolution of N_2 is lower than that of CO_2 in heavy oil, but it can recover the reservoir pressure and play a role of auxiliary cleanup. (5) N_2 is an insulation gas, which can reduce the heat loss of injection steam. (6) The dissolution of generated gas can form foamy oil which also improves the development performance of heavy oil. For these reasons, HW-MTFS process has higher oil rate and production than CSS process in limited time, and it will become an effective and important technique for developing offshore heavy oil reservoirs.

Conclusions

(1) In the injection steam process of horizontal well in heavy oil reservoir, the pressure and temperature along horizontal wellbore gradually decreased due to friction loss and heat loss.
(2) Increasing steam injection rate could effectively increase the thermal effective range of steam. Noncondensate gas in multi-thermal fluid could improve the thermophysical properties of fluids and reduce the heat loss and pressure drop along the horizontal wellbore. The distribution of pressure and temperature along horizontal wellbore was also closely related to the position of injection steam. The injection steam position of horizontal well had larger heating range, faster fluid flow and better heating effect. Permeability directly affected the seepage ability of injected fluid in formation. The higher the formation permeability along the horizontal wellbore was, the stronger the steam absorption capacity and the better the heating effect were. The steam absorption profile of horizontal slotted wells in the heavy oil reservoir was more uniform and effective than that of horizontal perforated wells.

(3) In the production process of actual reservoir, in order to attain the uniform steam absorption profile along the horizontal wellbore, the position of injection steam could be changed periodically. In addition, the heating effect and steam absorption profile could be improved by concentric or parallel two-pipe section injection technique.
(4) Compared with CSS process, in addition to the conventional thermal recovery mechanisms, HW-MTFS process also had some other mechanisms such as gas dissolution, energy recovery, heat insulation and auxiliary cleanup. Therefore, HW-MTFS process had higher oil rate and recovery than CSS process in limited time. In view of the special requirements of developing offshore heavy oil, HW-MTFS process will become an effective and important technique for developing offshore heavy oil reservoirs.

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