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Simulating CO_2 and Viscosity Dissolver Assisted Steam Flooding Technology in Extra-Heavy Oil Reservoir by Using 3-D Physical Modelling

WANG Chunzhi[a],*; LI Zhaomin[a]; LI Songyan[a]; LI Binfei[a]; LIU Wei[b]

[a] School of Petroleum Engineering, China University of Petroleum, Qingdao, China.
[b] College of Energy Resource, Chengdu University of Technology, Chengdu, China.
*Corresponding author.

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Abstract
The macroscopic fluid flow mechanism of enhanced oil recovery (EOR) by CO_2 and viscosity dissolver assisted steam flooding technology for horizontal well (HDCS) is studied using "the 3-D physical modeling system of a complicated driving system under the realreservoir condition (high temperature and high pressure conditions) for EOR". The production performance, pressure field and saturation field are measured with a differential pressure unit and saturation measuring probes. The resistance increased, the pressure increased and the flow direction changed under the physical and chemical actions of adsorption and the retention of the tannin extract. The tannin extract changed the flow direction from the main stream to the remaining oil regions on either side and displaced the remaining oil. The steam flooding not only displaced the residual oil in the main stream but also displaced the oil on either side by enlarging the swept volume from the main stream to the side.

Key words: Horizontal wells; Steam flooding; Enhanced oil recovery (EOR); Pressure field; Saturation field; Fluid flow mechanism; 3-D physical mode; Tannin extract

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INTRODUCTION
The production of conventional crude oil has been decreasing because of its depletion in reservoirs and the world-wide increasing oil demand. As an alternative oil resource, unconventional oils, such as extra-heavy oil, bitumen, oil sand and oil shale, have been investigated. Heavy-oil and bitumen resources have a significant effect on meeting this demand because of their large but almost untouched volume. Thermal recovery methods are the most appropriate for increasing the production from heavy oil reservoirs because thermal methods reduce the viscosity of heavy oil and increase its mobility. The economical use of heavy oil reservoirs is therefore possible[1-8]. Steam injection is currently used as one of the most successful enhanced oil recovery methods for heavy oil reservoirs. However, the recovery efficiency and effectiveness of this method are often limited by early gas break-though at a producing well because of overriding and steam channeling.

China has abundant heavy oil resources and recently discovered massive extra heavy oil reservoirs in the Shengli and Liaohe oilfields. Many super-heavy oil reservoirs are deeply buried and thin, with a high oil viscosity and poor mobility[1]. When the oil viscosity exceeds 100,000 mPa·s, conventional steam huff-and-puff displays poor economic returns. Since 2008, the Zheng-411 oil-block well-group throughput cycle has generally had more than 8 cyclic steam stimulation productions. This process has faced several issues: (a) After many repeated courses of throughput, the wellbore region has high degree of recovery, but a large quantity of oil remains in the inter-well; (b) The formation pressure displays a large decrease; (c)The drainage has a long period and the multi-composite stimulation exhibits poor performance; and (d) The speed of production declines faster[2-6].

According to the throughput stage production data (up to July 8, 2012) obtained by a numerical simulation cyclic steam stimulation production trends, the production data for each production well and the digital-analog temperature field analysis, we found that the block reasonably transfers

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into steam stimulation production using steam flooding. This process conducted 6 courses of a steam huff-and-puff experiment before steam flooding, and the recovery factor was reduced to less than thirty percent.

Steam flooding has been extensively implemented in heavy oils, but the application of this method to improve the oil recovery in deep and thin reservoirs is rare. In this study, steam flooding and steam+foam/tannin extract flooding were performed in a three-dimensional radical core-flood apparatus.

1. EXPERIMENTAL SECTION

1.1 Experimental Apparatus

The experimental apparatus is shown in Figure 1. The fundamental parameters are as follows: The size of the model is 500 mm × 1,000 mm; the total volume of the three-dimensional model is 196.35 L; the injection pressure is 4.3~5 MPa; and the temperature is constant at 250~280 ºC.

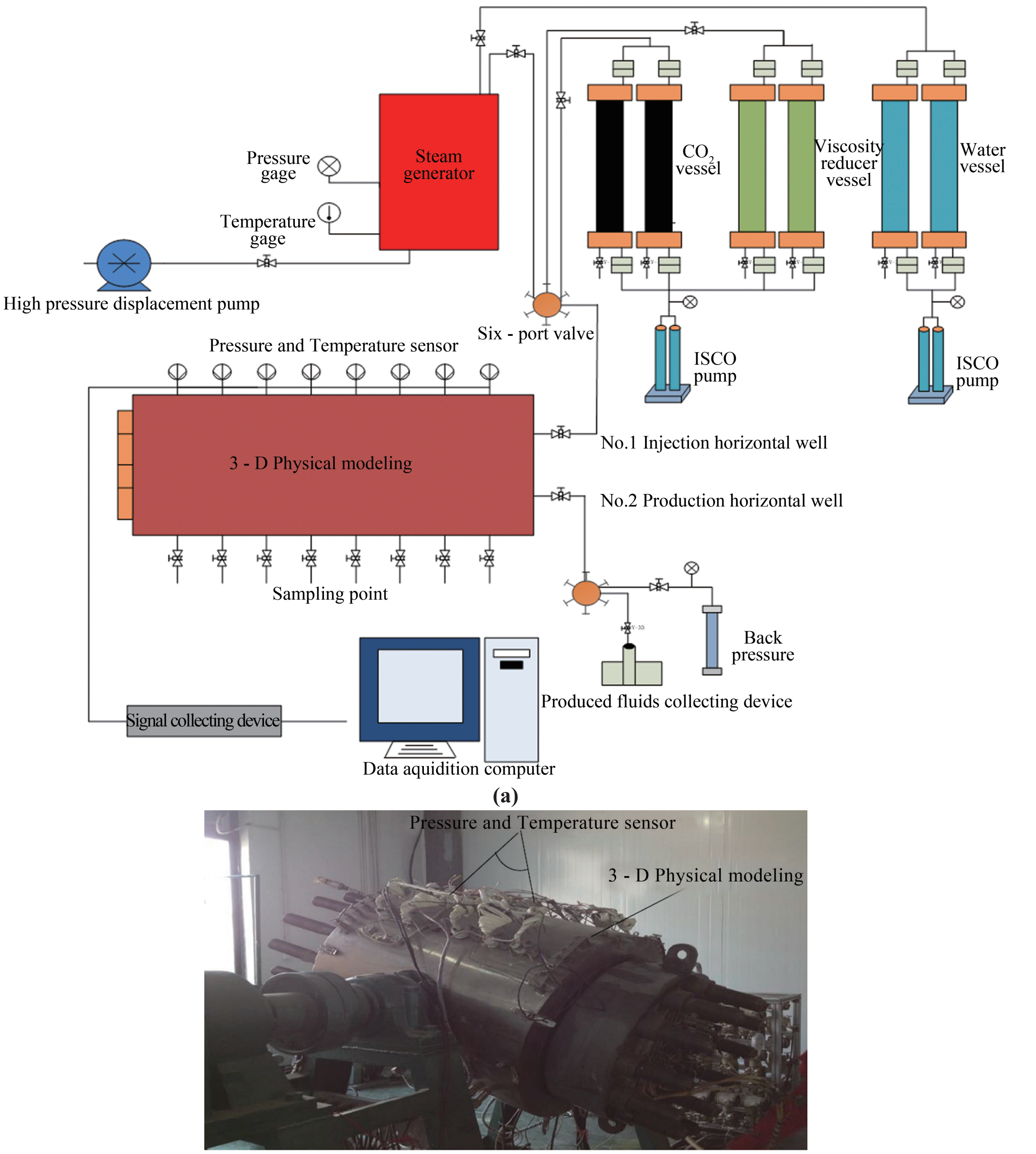

Figure 1
(a) Experimental Facility and Flow Diagram of the Experiment, (b) Picture Showing the Main Components of the 3-D Physical Model Setup

The core component in Figure 1 is a three-dimensional radical core-flood apparatus composed of stainless steel. Compared to a linear core-flood system, this apparatus has the distinctive advantage of better simulating the radial flow around a horizontal wellbore in an oil formation. The three-dimensional radial core-flood apparatus is composed of stainless steel; therefore, the apparatus can withstand pressures of up to 30 MPa. The core-flood apparatus is a cylindrical vessel with a diameter of 50 cm. The temperatures required for the experiments are achieved by placing the cylindrical simulator vessel in an air bath.

The core-flood apparatus is equipped with multiple sets of temperature measuring points and wells. Figure 2 shows the distributions of the temperature measuring points and wells within the radial core-flood apparatus. Thirteen temperature measuring points monitor the middle layer temperature of the core-flood apparatus. One injection well is located in the center of the core-flood apparatus within one production wells. The length of the wells is 90 cm with a perforation length of 80 cm. The diameter of the well is 0.8 cm.

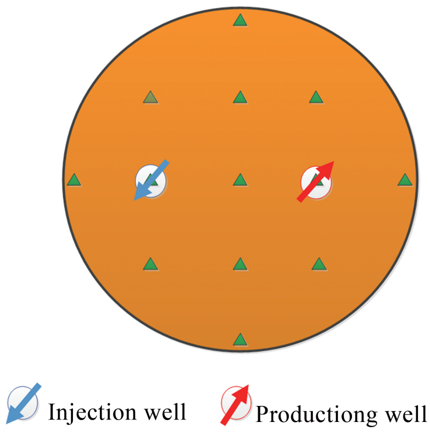

Figure 2
Distributions of the Temperature Measuring Points and Wells Within the Core-Flood Apparatus

1.2 Experimental Methods

The specific operating procedure is briefly described as follows: (a) The sand pack is evacuated for 72 hours and water is injected at the rate of 1 ml/min. The core-flood apparatus is filled with distilled water and positioned vertically, and fresh 100-120 mesh quartz sand is added in several increments to fill the vessel. During this process, the water surface is maintained above the top of the sand to ensure that air was not introduced into the sample. (b) The degree of the porosity is calculated, and the valve in the lower part of the 3D-model is opened. The sand is saturated with oil at the speed of 2 ml/min, and the volume of the saturated oil is then calculated. The temperature is maintained constant at 200 ºC for 24 hours. (c) The oil injection was continued until water production was ceased (the water content was less than 1%). After oil injection, the inlet was closed and the cyclic steam simulation was conducted. The oil-soluble viscosity-reducing agent SLKF (100 ml) was injected into the 3D-model through the injection horizontal well at 1 ml/min. CO_2 (300 ml) was then injected, and the temperature was maintained constant for 12 hours.

The injection and production horizontal wells began with the steam stimulation production and then 20 mL of the viscosity reducer (injection rate 2 mL/min) and 100 mL of CO_2 (injection rate of 2 mL/min) were injected. The wells were shut for 12 hours and then injected with 1,000 mL of steam (15 mL/min). The best soak time for the steam injection was 5 hours before opening the well to production. The oil sample was saved for a component analysis. Following the above process and after the end of the first six stages of the cycle, the throughput was incorporated into HDCS flooding.

After the DCS (viscosity reducer + CO_2 + steam stimulation) production stage, the oil wells produced a total of 3,621.68 g of crude oil. The recovery of this stage was 10.25%, and abundant oil was noted in the model.

At this time, the production well was turned into an injection well. The injection horizontal well was the producing well. The mode of production was changed from steam stimulation into steam flooding.

2. RESULTS AND DISCUSSION

2.1 The Effect of Steam Flooding

As Table 1 and Figure 2 show, nitrogen foam is injected when the cumulative injection reaches 2 PV. The steam and foam are then injected together, but the result does not perform well. The steam and foam, combined with the tannin extract, are injected when the cumulative injection is 8 PV. We also simultaneously increase the temperature of the model before the injection of the tannin extract.

From the change in the oil production and water ratio in Table 1, the tannin extract coupled with foam can contribute to control the profile efficiently. The oil production is greatly decreased, and the water ratio is reduced to its minimum value. Therefore, the tannin extract coupled with foam are applied to control the profile of a serious of steam channel models effectively.

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Table 1
The Injected Fluids in the HDCS Displacement Stage

RUN No.	Experimental scheme	Viscosity reducer/ml	CO_2/ml	STEAM/PV	N_2 foam/L	Tannin extract
1	Viscosity reducer+CO_2+steam	100	300	1.1	——	——
2	Viscosity reducer+CO_2+steam	100	300	1.2	——	——
3	Foam+viscosity reducer+CO_2+steam	100	300	1.3	1.0	——
4	Viscosity reducer+CO_2+steam/foam	100	300	1.4	0.6	——
5	Tannin extract + viscosity reducer + CO_2 + steam	100	300	1.4	——	0.5
6	Viscosity reducer+CO_2+steam/foam	100	300	0.5	0.6	——
7	Tannin extract + viscosity reducer + CO_2 + steam	100	300	0.5	——	0.5
8	Tannin extract+ viscosity reducer + CO_2 + steam/ foam	100	300	0.7	0.6	0.8
9	Tannin extract + viscosity reducer + CO_2 + steam	100	300	0.8	0.6	1.2
10	Tannin extract + viscosity reducer + CO_2 + steam	100	300	0.8	0.6	1.0

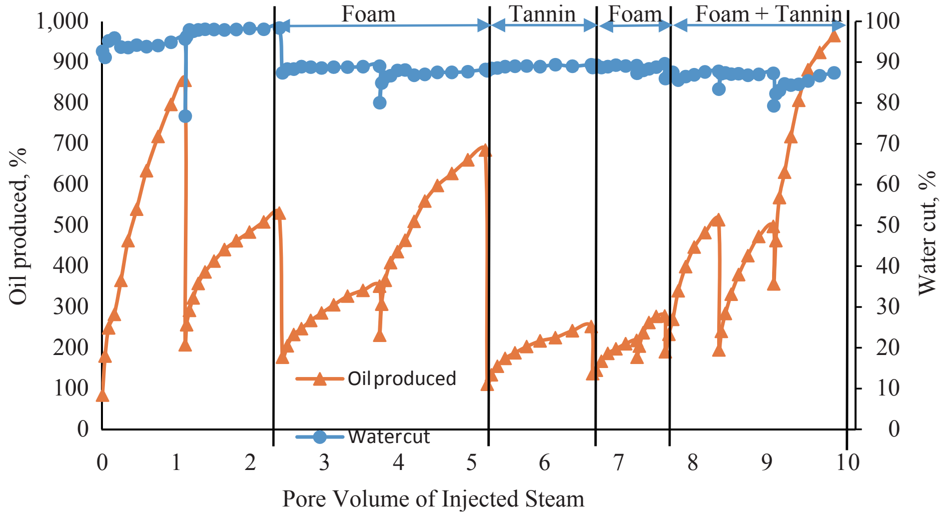

Figure 3
Oil Produced/Water Cut as a Function of the Pore Volumes of the Injected Steam

From Figure 3, the oil production and water ratio increase in steam flooding. Although the water ratio has a large fluctuation when the cumulative water injection reaches 4 PV, the decreased degree is limited because it maintains a high water-cut stage.

Because of the gas channeling of steam, we utilize different methods to address the different slugs in the HDCS flooding. The orders of the injected fluids and oil production and the change of average water ratio in the flooding stage are shown in Table 1 and Figure 3, respectively.

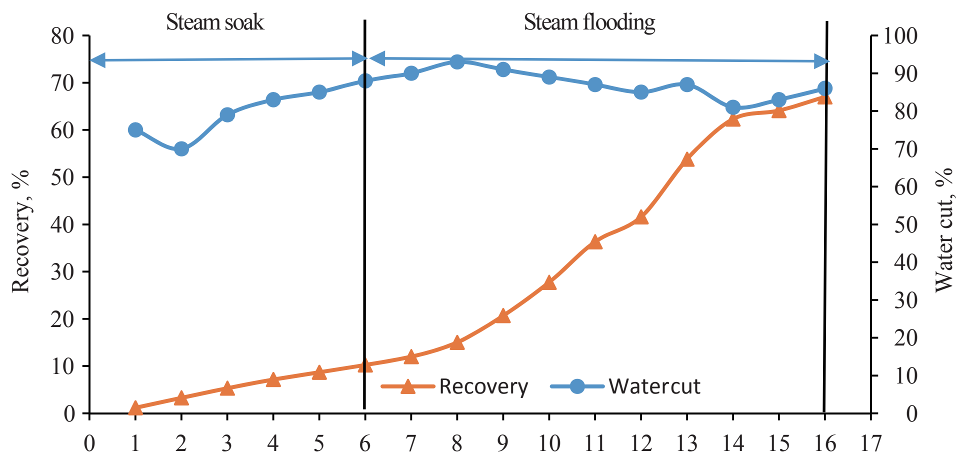

Figure 4
The Exploitation Curve of the Effect of HDCS Technology

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From Figure 4, under the conditions of this experiment, the steam huff-and-puff recovery rate was 10.08%. At the end of steam flooding, the recovery was 59.8%. The final recovery of polymer flooding was 67%. From the water cut curve, the water entered into the steam at approximately 0-1 PV. At the end of the steam flooding, the water rate reached approximately 86%. The steam flooding stage of the water cut increased rapidly, and the water cut rose to the highest point (98%). A funnel was noted in the water cut curve; the main reason for this funnel was the retention of the extract by adsorption and the production of retention in the porous rocks, thereby reducing the effective permeability of water. From the recovery curve, the recovery rate displayed rapid increases during the steam drive stage. By comparing the moisture contents and recovery rate curve, the moisture content decreased and the rising phase recovery was concentrated in the steam flooding stage. In the subsequent stages, the water content increased rapidly and the recovery increases slowly, finally remaining unchanged.

2.2 The Change in the Temperature Field During Steam Flooding

The horizontal well row pattern of the steam flooding time temperature contour line is shown in Figure 5. By analyzing the temperature of the homogeneous experimental model contour map, the steam from the steam injection well after the injection of the steam chamber gently pushes to the proceeding well, and the steam cavity shape is at its highest. The horizontal well with an end temperature along the horn process is gradually reduced. Using the heterogeneous models to produce temperature contour maps, the steam from steam injection well (after the first injection) break through along the high permeability zone. Because of steam channeling resulting in horizontal wells of low permeability with toe end temperature, the heat loss is largely heterogeneous.

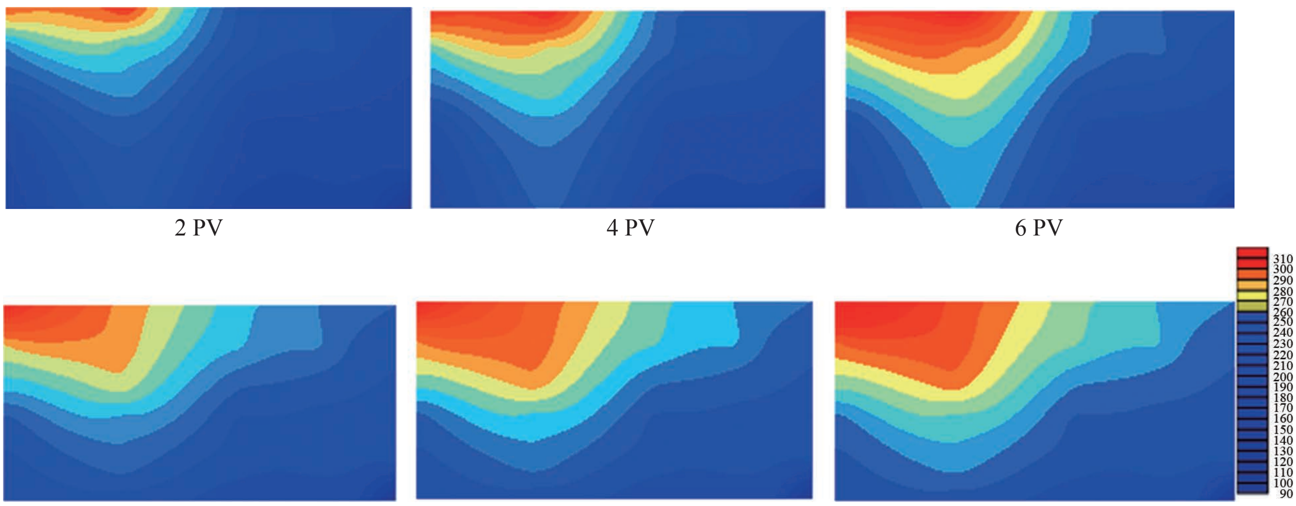

Figure 5
The Changes in the Temperature Field During Steam Flooding

2.3 The Change in the Pressure Field During Steam Flooding

Using Darcy's law for the potential field distribution of the pressure change, the dynamic reservoir fluid flow was reflect and the reservoir fluid flow was able to be used to analyze the change of pressure. Based on the production wells, injection wells mainstream line, and non-mainstream line, the degree of pressure change of each point was analyzed and the DCS (viscosity dissolver+CO_2+steam) flooding enlarged the sweep volume. Therefore, the macroscopic percolation mechanism of steam flooding was analyzed. The physical model pressure change curve shows that in the steam injection stage, the injection pressure rapidly increased.

It can be founded from Figure 6 that the steam flooding model reflects the pressure field. After injection of the tannin extract, the formation model of the pressure field changes. The hypertonic channel is effectively controlled. The pressure field distribution is greatly improved and the swept area is significantly expanded. From analyzing the pressure field during steam flooding, the main stream line (diagonal) on both sides of the pressure value was significantly higher than that of the non-main stream line area pressure value. Additionally, an isoline dense band was noted along the high pressure gradient belt. The high pressure gradient band stretched gradually from the main stream line to both sides of the non-main stream line in the residual oil zone, improving the scope. In the reservoir, a high pressure gradient displayed a formation time, motion velocity, oil wall formation time and a speed that were basically identical. Therefore, the reservoir pressure gradient of different times also reflects the change of oil and wall motion.

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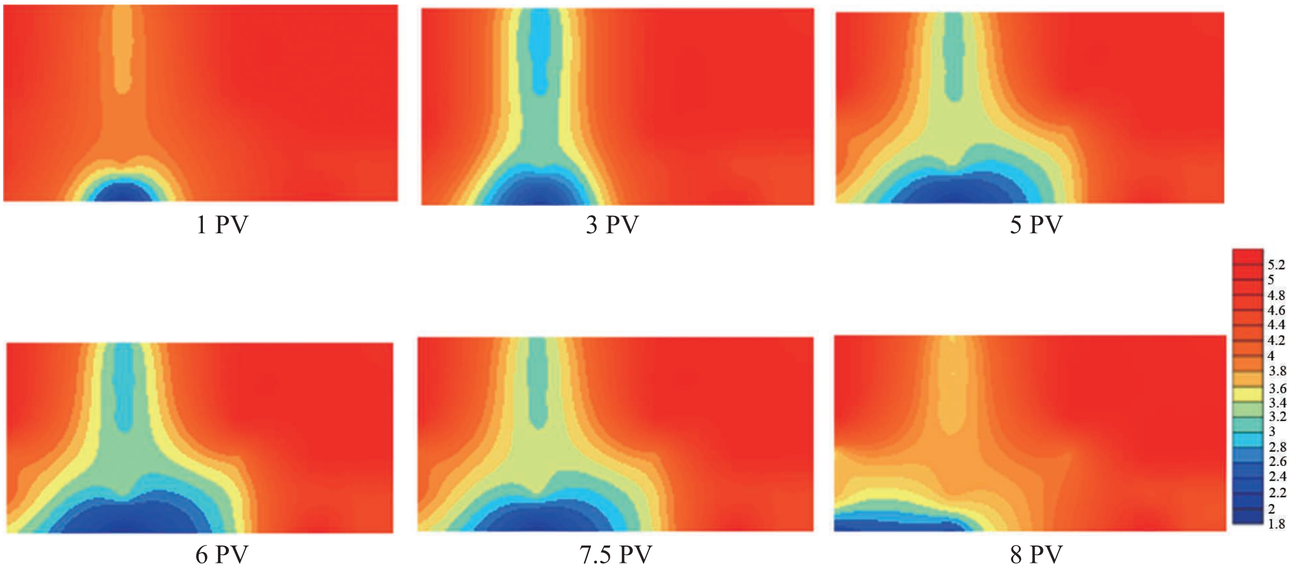

Figure 6
The Changes of the Pressure Field of Steam Flooding Between Injection and Production Well

CONCLUSION

Three-dimensional radial core-flood tests were performed to evaluate the potential of HDCS technology (horizontal well + viscosity dissolver + CO_2 + steam) to enhance heavy oil recovery. The results indicate the following:

(a) Through the use of the three-dimensional physical model, an experimental study was successfully performed for steam flooding oil in a large-sized 3-D consolidated reservoir physical model. The pressure HDCS exploitation effect and the temperature field were measured. The HDCS technology is used to improve the macroscopic percolation mechanism of recovery.

(b) For the three-dimensional physical models, the adsorption and retention of tannins in the reservoir increases the flow resistance and pressure and diverts reservoir fluids. Steam displaces the remaining oil along the main streamline and elsewhere. By increasing the sweep range, the steam displaces the remaining oil on both sides of the streamline, forming an extended mainstream line on both sides of the wall to the oil in the reservoir. This increased displacement range improves the macro swept volume.

(c) The steam flooding process will produce a certain pressure gradient belt that is basically identical to the formation pressure gradient time and oil wall forming time. Therefore, the pressure gradient changes in the reservoir and reflects the changes of the oil and wall motion.

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