Study on Flow Characteristics of Produced Fluid in Bohai Oilfield Cycle Steam Stimulated Heavy Oil Reservoir

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Abstract. It is helpful to better understand the flow state of produced fluid in different stages by studying the flow characteristics of produced fluid of cycle steam stimulation (CSS in short) heavy oil reservoirs from the reservoir to the wellhead, and to provide more research for the CSS replacement technologies for a clear direction. However, there are few studies on the flow state of produced fluids, and the mechanism understanding is not very clear. This article starts with laboratory experiments to study the factors that affect the fluidity of heavy oil in the Bohai Oilfield. It is found that temperature, water content of W/O emulsion, and shear rate have a greater effect on the viscosity of produced fluid in heavy oil reservoirs in Bohai Oilfield, while pressure and N₂ dissolution have less effect on the produced fluid viscosity. Due to the different flow speeds of the produced liquid in different flow stages, the equivalent shear rates are different. Therefore, when studying the flow characteristics in different flow stages, it is necessary to consider the effect of the difference in flow velocity. The effect of pressure and nitrogen dissolution on the viscosity change of produced fluid is very small. And then, based on high-precision historical fitting by using reservoir numerical simulation, the CSS development of Bohai Oilfield was predicted. Finally, combined with the numerical simulation results and the results of laboratory experiments, a wellbottom temperature calculation plate, a viscosity plate of produced fluid flowing from reservoir to wellbore, a viscosity plate of produced fluid flowing in horizontal wellbore and a viscosity plate when produced fluid flows to the wellhead. According to the chart, the viscosity of the produced fluid at different development stages and different flow positions can be judged and predicted, so that the fluidity difference of the produced fluid at different positions can be obtained, and it can provide guidance for the research on replacement technology after CSS in Bohai Oilfield.

1. Introduction
Cycle steam stimulation (CSS in short) is one of the most effective method for heavy oil production which can make a remarkable enhanced heavy oil recovery [1]. However, during the development of heavy oil reservoirs by CSS, the water contacted with the heavy oil and emulsified to form a W/O emulsion by the action of emulsifying components in the heavy oil [2]. The viscosity of W/O emulsion increases with increasing of water content in the W/O emulsion. With the development of CSS, the emulsification phenomenon becomes serious, and the viscosity of the W/O emulsion rises, which leads to the poor development effect [3-6].

There are more comprehensive studies on the preparation of emulsions, macroscopic stability and stabilization mechanism. The factors that affect the W/O emulsification state are mainly related to the nature of the heavy oil, the type of emulsifier, the water content, the temperature, and the shear rate [7-10]. As the water content changes, the viscosity of the oil-water emulsion changes accordingly, and for different heavy oils, the change trend is different, which depends on the composition of the heavy oil.
Since resin and asphaltene are good natural emulsifiers, they can easily adhere to the oil-water interface to form a stable W/O type heavy oil emulsion, thereby increasing the viscosity of heavy oil [10]. The effect of water content on the viscosity of emulsions has two aspects. If oil-water emulsion forms a W/O emulsion, the viscosity increases, and if oil-water emulsion forms an O/W emulsion, the viscosity decreases significantly [7]. In a certain range of temperature, the temperature increase helps oil-water emulsification, because the molecular cohesion weakens with temperature increase, it helps to reduce the accumulation of resin and asphaltene in heavy oil, and it helps to form water-in-oil emulsion [4]. When the temperature continues to increase, the temperature would cause large-area damage to the accumulation of resin and asphaltene, causing the resin and asphaltene attached to the W/O emulsion interface film to lose their emulsification and then the effect of demulsification occurs. The viscosity of the emulsion is affected by the shear rate, but there are few studies on the proportion and trend of the effect of the shear rate on the viscosity.

The current research on the harm caused by the emulsion formed by the produced fluids in heavy oil reservoirs has mainly focused on transportation, storage, and refinery processing [11]. Mainly manifested in: (1) the increase in power consumption during the gathering and transmission process [12, 13]; (2) the increase of fuel cost during the heating process [14, 15]; (3) the increase in fluid volume, which reduces the effective utilization of equipment and pipelines [16]; (4) the increase in costs during the refinery process [17, 18]. However, there are few studies on the effect of emulsification on the production fluid during the development process, especially in the reservoir conditions. Because for the heavy oil reservoirs developed by using the CSS method, as CSS progresses, the water content in the heavy oil reservoir gradually rises, and the injected water would emulsify with the formation heavy oil to formed an W/O emulsion, which increases the viscosity of the produced fluid and weakens the fluidity [19-21].

Bohai Oilfield conducted a pilot test area for CSS and achieved good development results [22]. However, with the development of CSS, especially in the middle and late stages of CSS, heavy oil and water are prone to form W/O emulsions during thermal recovery, which causes serious reduction in development [23]. Figure 1 is the dynamic curve of development of Well-1. The Well-1 was cold-produced before CSS and the Well-1 is undergoing the cycle steam stimulation. For offshore oilfields, it has entered the middle and late stages of CSS. With the progress of steam throughput, the water content rate rises rapidly, and the liquid production volume decreases severely. It severely restricts the efficient development of CSS in Bohai Oilfield, and it is urgent to study the replacement technology of CSS in the middle and late stages.

![Figure 1 Dynamic curve of development of Well-1](image_url)

Because the produced liquid flows through different flow media throughout the flow process, the flow state is also different, as shown in Figure 2. When the produced fluid flows from the reservoir to the wellbore, the medium flowing through is the reservoir, and the area flowing through is the pores on the wellbore surface of the entire completion section. When the produced fluid flows in the wellbore, the flowing area is the cross-sectional area of the wellbore. After the produced fluid flows into the tubing, the flowing area is the cross-sectional area of the tubing. During the flow of the produced liquid, the flow velocity also varies due to the different cross-sectional areas. When entering the tubing to the wellhead for production, although the
flow velocity is the same, the temperature of the produced fluid is different. A clear understanding of the fluidity differences of produced fluids in heavy oil reservoirs at different stages of the CSS would help the research on the replacement technology of heavy oil reservoirs after the CSS, and determine the technological research focus of CSS replacement technology at different times and different flow stages.

Figure 2 Schematic diagram of produced liquid flow state

This study mainly analyzes the influencing factors of heavy oil fluidity in Bohai Oilfield, and then establishes a numerical simulation model for Bohai Oilfield reservoirs by using the STARS module of CMG. Based on high-precision matching, it predicts the effects of CSS in Bohai Oilfield. Based on lab experiments and reservoir numerical simulation, a production fluid flow model for heavy oil reservoirs of Bohai Oilfield is established and the model is solved. Finally, a produced fluid temperature calculation plate in well-bottom, a production fluid viscosity plate flow from the reservoir to wellbore, a viscosity plate when the produced fluid flows in a horizontal wellbore and a viscosity plate when the produced fluid flows to the wellhead are established. According to the temperature, water content, and viscosity of the produced fluid at the wellhead, the viscosity of the produced fluid at different periods and at different positions can be calculated through the plate, so that the fluidity of the produced fluid at different positions can be judged which can provide guidance for the study of replacement technology of CSS for heavy oil reservoir of Bohai Oilfield.

2. Experimental

2.1. Experimental materials.
The oil for the experiment is from the degassed and dehydrated heavy oil which was provided by Bohai Oilfield. The heavy oil can easily generated W/O emulsion because the high composition of resin and asphaltene (total 21.4%) [24, 25], and the SARA compositions are listed in Table 1. The water is deionized water made by a Millipore1 Elix-10 purification apparatus. The purity of nitrogen is 99.9% and is produced by Beijing Beiwen Gas Manufacturing Company.

| Group Composition | Content |
|-------------------|---------|
| Saturated Hydrocarbon | 53.6 %   |
| Aromatic Hydrocarbon | 25.0 %   |
| Resin              | 20.5 %   |
| Asphaltene        | 0.90 %   |

2.2. Experimental apparatus.
The HAAKE MARS IV rheometer with highest test temperature is 300°C, the highest test pressure is 40 MPa is used for the viscosity measurement of emulsion. The Olympus BX53 electron microscope with magnification of 40-1000 times is used for micro status observation of emulsion. The SARA
tester was perchance from Dalian North Instrument Co., Ltd, and the Olympus SAII-2 Emulsifier test rotation is range of 0-28000 r/min.

2.3. Experimental procedures.

2.3.1. Heavy oil-water emulsification. Because heavy oil is extremely sensitive to temperature. The viscosity of heavy oil decrease as the temperature increase. The CSS is the most common development method for heavy oil reservoirs development. But as steam stimulation continues, water stayed in the formation increase, and a stable W/O emulsion could generated because resin, asphaltene and cycloalkane are good natural emulsifiers in the heavy oil which are easy to adhere to the oil-water interface. As the water in the W/O emulsion increase, the viscosity of the W/O emulsion would also increase. The water in the W/O emulsion would effect the development of heavy oil reservoir, so the viscosity of the W/O emulsion in different water content were tested. The water in the W/O emulsion was added by multiple times, so that it is more conform to actual emulsification of the oilfield.

2.3.2. Viscosity and rheology test. During the CSS process, in order to ensure that the heat injected by the steam fully heats the formation, the method of thermal insulation development is usually accompanied by the injection of N$_2$. In order to study the influence of pressure and gas dissolution on the viscosity of the Bohai heavy oil. When studying the effect of gas dissolution on the viscosity of heavy oil, N$_2$ dissolved in heavy oil is used for testing. The experimental pressure range is 0-7 MPa, and the temperature is 50 °C. When considering the influence of pressure, N$_2$ is added to the closed system at a pressure higher than the test pressure of 4 MPa to pressurize, and after 10 hours of stabilization, the pressure was reduced to the test pressure for the experiment. Then reduce the pressure to the test pressure and continue stirring, and perform the experiment when the pressure stabilizes to the test pressure. The viscosity of the W/O emulsion or heavy oil in different shear rate conditions is determined after the sample in the closed system reaches a certain temperature and is stabilized. In order to ensure the accurate of test results, sufficient time (30 min) is required to allow uniform temperature and elastic recovery of the sample during warming or shearing conditions. The shear rate was 5 s$^{-1}$ during the viscosity test.

2.3.3. Study on micro-emulsification state of W/O emulsion. An Olympus BX53 microscope was used for the observation of microscopic emulsification, which can observe the difference in the emulsification state of the emulsion at different water content. The observed samples were prepared by using cell scraping. By observing the emulsified state of the emulsion, the effect of the emulsified state on the viscosity can be obtained. The water content of W/O emulsion with 10%, 30%, 50% and 70% were photograph the structure by electron microscopy.

3. Results and discussion

3.1. Effect of emulsification and temperature on flow property of oil and water system. The water content of W/O emulsion has a very big influence on its viscosity. It can be seen from Figure 3 that as the water content increases, the viscosity of the W/O emulsion increases. The viscosity of W/O emulsion with 70% water content is 21.05 times to the viscosity of the dehydrated heavy oil at 50 °C. As the water content increases, the viscosity of the W/O emulsion increases more significantly when the water content is greater than 40-50%, which is consistent with the situation in the oil field. The W/O emulsion water content late stage of steam stimulation is generally higher than 50%, and the viscosity of W/O emulsion is high at this time, which would severely restricts the efficient development of heavy oil reservoirs. In addition, when the W/O emulsion flows from the bottom of the well to the well head, its temperature would gradually decrease, so the viscosity would increase, and it will be difficult to lift.
From the micro-emulsification state of W/O emulsions with different water content (Figure 4), it can be seen that with the increase of water content, the size and number of water droplets in the W/O emulsion are changing. With a water content of 40-50%, the emulsification state is different. Under low water content conditions, as the water content increases, the diameter of the water droplets gradually increases. Under high water content conditions, as the water content increases, the particle size of the water droplets remains unchanged, but the number of water droplets increases. When the water content is higher than 40-50%, the oil phase film between the water droplets is very thin. When subjected to shear, the thinner the oil phase film, the greater the internal frictional resistance. Therefore, under high water content conditions, the viscosity of the W/O emulsion increases significantly.

3.2. Effect of pressure and N₂ dissolution on flow property of oil and water system

In order to conform to the existence of heavy oil in the formation, the HAAKE MRASIII rheometer closed system module was used to test the viscosity of heavy oil under different pressures and dissolved N₂, and to study the effect of pressure and dissolved N₂ on the viscosity of heavy oil. The test results are shown in Figure 5.

It can be seen from Figure 5 that the viscosity of the heavy oil increases as the pressure increases, and the viscosity of the dissolved N₂ heavy oil decreases. The viscosity of dehydrate heavy oil at 50°C is 3665.0 mPa·s when there is no pressure and N₂ dissolution. When the pressure is 7 MPa and no gas is dissolved, the viscosity of heavy oil is 3897.1 mPa·s, and the viscosity only increases by 6.33%; the viscosity of heavy oil is 3856.0 mPa·s when the pressure is 7 MPa and the N₂ is dissolved, and the viscosity is reduced by 3.13% compared to the case without the N₂ dissolved and the pressure is 7 MPa. Moreover, by comparing the test results in different water and test temperature conditions, it can be seen that as the temperature increases, the effect of pressure and N₂ dissolution on viscosity increases; as the water content increases, the effect of pressure and N₂ dissolution on viscosity increase. However, the viscosity of the heavy oil at the pressure is 7 MPa is only 1.15 times that no pressure (water content 50, 120°C).

In summary, Pressure and N₂ dissolution have little effect on the viscosity of heavy oil in Bohai Oilfield. Among the factors that affect the viscosity of heavy oil in Bohai Oilfield, pressure and N₂ dissolution are not the main influencing factors. Therefore, the influence on the viscosity of heavy oil in Bohai Oilfield is not considered in this study.
3.3. Effect of shear rate on flow property of oil and water system.

During the development of heavy oil reservoirs, the flow cross-sectional area of the produced fluid flowing from the reservoir to the wellhead is different, which makes the produced fluid flow speed, the shear force to which it is subjected, and the flow shear rate are different. In order to study the difference in viscosity of produced fluids at different flow stages, experiments were designed to study the effect of shear rate on produced fluid viscosity. The test results are shown in Figure 6.

It can be seen from Figure 6 that the influence of shear rate on the viscosity of heavy oil is relatively large. As the shear rate increases, the viscosity increases first, then decreases, and finally...
stabilizes. It can be seen that the viscosity increases 1.42 times when the shear rate has the greatest effect on the viscosity change (water content 50%, temperature 100°C). And the shear rate has the smallest effect on the viscosity change over 20%. Therefore, in studying the flow characteristics of the produced fluid during the produced process, the influence of the shear rate on the viscosity change must be considered. More elaborate experiments were designed to test the change in viscosity of W/O emulsions at different temperatures with shear rate in different water content conditions. It provides a data basis for the subsequent research on the fluidity differences of the produced fluids at different development stages.

### 3.4. Variation of flow property of oil and water system during production process

By studying the factors that affect the fluidity of heavy oil reservoir fluids, it can be found that temperature and water content have the greatest effect on the viscosity of production fluid; shear rate has a greater effect on the viscosity of production fluid, and pressure and N₂ dissolution have the smallest effect on the viscosity of production fluid. During the production of heavy oil reservoirs by CSS, fluid production rate, temperature and water content are constantly changing. The wellhead temperature, well bottom flow temperature, wellhead produced fluid flow rate, well bottom flow rate of produced fluid, and flow rate of produced fluid in the reservoir also constantly change. Therefore, the viscosity of the produced liquid is also different at different timings and different flow stages of CSS. It is necessary to establish a fluidity model of produced fluids in heavy oil reservoirs to further understand the viscosity changes of produced fluids in different CSS periods and different flow stages in oilfields, and to provide guidance for the study of CSS replacement technologies. The fluidity model of heavy oil reservoir produced fluid in this study is based on the following five assumptions: 1) The flow of produced fluid from the reservoir to the wellbore is an isothermal flow process. 2) Water content of produced fluid flowing from reservoir to wellhead does not change. 3) Friction resistance is not considered during the whole flow of produced fluid from reservoir to wellhead. 4) The production fluid flow process is oil and water two-phase flow, and the oil and water are emulsified. 5) Produced liquid is evenly distributed along the perforation section.

Based on the above five assumptions, the flow rate of the produced liquid in the three stages: produced fluid flows out of the reservoir, produced fluid flows from the horizontal section to the oil pipe and produced fluid enters tubing can be calculated according to Eq. (1) to Eq. (3).

\[
\begin{align*}
    v_1 &= \frac{Q}{86400 \phi g D_1} \quad (1) \\
    v_2 &= \frac{Q}{86400 \phi g \left( \frac{D_1}{2} \right)^2} \quad (2) \\
    v_3 &= \frac{Q}{86400 \phi g \left( \frac{D_2}{2} \right)^2} \quad (3)
\end{align*}
\]

\(v_1\) represents the flow velocity of the produced fluid when it passes from the reservoir into the wellbore; \(v_2\) represents the flow velocity of the produced fluid when it passes from the wellbore to the tubing; \(v_3\) represents the flow velocity of the produced fluid after entering the tubing, and their units are m/s. \(Q\) is the daily fluid production rate, m³/d; \(L\) is the horizontal section length, m; \(D_1\) is the diameter of the wellbore, m; \(D_2\) is the diameter of the tubing, m; \(\phi\) is porosity, decimal.

According to the actual wellbore parameters of Bohai Oilfield which substituted into Eq. (1) to Eq. (3), and the flow velocity calculation Equations of produced fluids at different flow stages can be calculated. Combining the relationship between the shear rate and the flow velocity (Eq. (4)), the equivalent shear rate of the produced liquid at different flow stages can be calculated, as shown in Eq. (5) to Eq. (7).
\[ \gamma \text{ (shear Rate)} = \frac{\text{Flow Velocity Difference}}{\text{Height of Flow Liquid Surface}} \] (4)

\[ \gamma_1 = \frac{Q_1}{6850} \] (5)

\[ \gamma_2 = \frac{Q_2}{383.67} \] (6)

\[ \gamma_3 = \frac{Q_3}{105.5} \] (7)

In Eq. (5) to Eq. (7), \( \gamma_1 \) represents the equivalent shear rate of the produced fluid when it passes from the reservoir into the wellbore; \( \gamma_2 \) equivalent shear rate of the produced fluid when it passes from the wellbore to the tubing; \( \gamma_3 \) equivalent shear rate of the produced fluid after entering the tubing, and their units are s\(^{-1}\).

From Eq. (5) to Eq. (7), the equivalent shear rate when the produced liquid flows to different positions in the same daily liquid production can be calculated. It provides a basis for studying the fluidity of produced fluid flowing from reservoir to wellhead.

Based on the geological model of the Bohai Oilfield, the STARS module of CMG was used to establish a numerical simulation model of the reservoir. The 3D view of the model is shown in Figure 7. According to the established numerical simulation model of the reservoir, combined with the field CSS and production dynamic data, the production dynamic history fitting of the numerical simulation model of the heavy oil reservoir in Bohai oil field was performed. Fitting curves of daily oil production, water content and well bottom flow pressure are shown in Figure 8 to Figure 10. The fitting accuracy is high. The subsequent numerical simulations of the reservoir were reliable.

**Figure 7** 3D view of numerical simulation model of the heavy oil reservoir in Bohai Oilfield

**Figure 8** History fitting curve of daily oil production
Based on the high-precision fitting numerical simulation model of the reservoir, the CSS development is continued to the 10th year according to the current development model of Well-1. Through the numerical simulation results of the reservoir, the effects of CSS in Bohai Oilfield are predicted. The development trend of CSS in Bohai Oilfield can be obtained, and statistics on the wellbottom temperature, wellhead temperature, daily fluid production rate, water cut and other data of the simulation results. The viscosity of the heavy oil in the Bohai Oilfield in different temperature, water content and shear rate conditions can be obtained through detailed laboratory experiments. Using the results of reservoir numerical simulation, a wellbottom flow temperature map for heavy oil reservoirs can be established. Combining the numerical simulation results of the reservoir with the results of laboratory experiments, the viscosity calculation plate for produced fluid flowing from the reservoir to the wellbore, the viscosity calculation plate for produced fluid flowing in the horizontal wellbore, and the viscosity calculation plate for produced fluid entering the tubing (The daily liquid production speed is 50m$^3$/d). The results of the plates are shown in Figure 11 and Figure 12.

In the case of high-precision historical fitting, reservoir numerical simulation is used to predict multi-round development of CSS in Well 1, as shown in Table 2. Using the results in Table 2 in combination with the plate, the viscosity of the produced liquid can be calculated from plates at different development periods and different flowing positions. The results are shown in Table 3. It can be seen that after multiple rounds of CSS, the water content of the produced liquid gradually increases. Although the temperature is also rising, the viscosity is still increasing significantly. When the reservoir was developed to the ninth cycle, the wellhead viscosity was still as high as 2953.84mPa•s even at the early stage. Therefore, research on CSS replacement technology is very necessary and urgent.

In the field application of the oilfield, the wellbottom flow temperature can be obtained from the wellbore flow temperature calculation plate (Figure 11) according to the temperature of the produced fluid at the wellhead. By testing the water content of produced fluid at the wellhead, the viscosity of the produced fluid flowing from the reservoir to the wellbore, flowing in the horizontal wellbore, and flowing in the tubing can be obtained using Figure 12. The plates can be used to judge the fluidity of the produced liquid at different periods and positions. It provides a basis for the targeted research of CSS replacement technology of Well-1 in oil fields in different periods and different positions.
Figure 11 Bottomhole flow temperature calculation plate of Well-1

Figure 12 Viscosity plate production fluid flows of Well-1 (a. from the reservoir to the wellbore; b. in the horizontal wellbore; c. flowing in the tubing)

Table 2 Development prediction of Well-1 by reservoir numerical simulations

| Cycle | Early Stage of CSS | | Middle Stage of CSS | | Late Stage of CSS |
|-------|------------------|------------------|------------------|------------------|
|       | Water Content /% | Wellhead Temperature /℃ | Wellbottom Temperature /℃ | Water Content /% | Wellhead Temperature /℃ | Wellbottom Temperature /℃ | Water Content /% | Wellhead Temperature /℃ | Wellbottom Temperature /℃ |
| 1     | 2                | 50                | 87                | 2.5              | 42                | 70                | 2.51              | 35.2                | 55                |
| 2     | 20.24            | 52                | 91                | 15.65            | 45.6              | 76                | 10.09             | 38.2                | 67                |
| 3     | 34.38            | 57.3              | 103               | 18.71            | 47.4              | 80.2              | 14.23             | 40.3                | 69.3              |
| 5     | 47.33            | 64.3              | 108.5             | 33.24            | 48.6              | 86.68             | 21.45             | 42.7                | 75.49             |
| 7     | 59.7             | 66.8              | 120.05            | 44.46            | 54.4              | 89.31             | 25.76             | 46.8                | 82.22             |
| 9     | 68.74            | 67.2              | 130.54            | 47.39            | 57.1              | 93.41             | 32.14             | 46.2                | 88.25             |

Table 3 Viscosity of Well-1 of produced liquid calculated by plates

| Cycle | Early Stage of CSS/mPa·s | Middle Stage of CSS/mPa·s | Late Stage of CSS/mPa·s |
|-------|--------------------------|---------------------------|-------------------------|
|       | 1 | 2 | 3 | 1 | 2 | 3 | 1 | 2 | 3 |
| 1     | 316.2 | 379.4 | 8904.1 | 711 | 831.9 | 12914.3 | 676.1 | 716.7 | 13596.4 |
| 2     | 354.8 | 436.4 | 9669.3 | 751.1 | 848.7 | 13822.1 | 787.9 | 854.9 | 15587.8 |
| 3     | 380.2 | 479.1 | 10322.7 | 862.6 | 1000.6 | 15717.9 | 954.9 | 1021.7 | 17909.9 |
| 5     | 501.2 | 633 | 12822.5 | 1294.3 | 1501.4 | 17228.4 | 1202.3 | 1298.5 | 20143.4 |
| 7     | 794.3 | 1003.2 | 14926 | 1459.7 | 1678.7 | 21228.4 | 2558.9 | 2738.0 | 25698.3 |
| 9     | 1412.5 | 1784 | 25938.4 | 1711.4 | 1951.0 | 40618.6 | 3430.0 | 3704.4 | 49963.9 |

*Position 1 means production fluid flows from the reservoir to the wellbore; Position 2 means production fluid flowing in the horizontal wellbore; Position 3 production fluid flowing in the tubing.
4. Conclusions
1) After entering the third cycle of CSS, Well-1 of Bohai Oilfield has a rapid decline in fluid production and a significant increase in water content. This is due to the low water recovery rate during the first two cycles, which caused more water to be deposited in the formation. Emulsion of heavy oil and water to form a W/O emulsion causes the viscosity of the produced liquid to increase, which makes the development effect of CSS worse.

2) Through laboratory experiments, factors affecting the viscosity of the produced fluid in the heavy oil reservoirs of the Bohai Oilfield were clarified. Temperature and water content have the greatest influence on the viscosity of the produced fluid. Shear rate has a significant effect on the viscosity of the produced fluid. Pressure and N₂ dissolution affect the effect of produced fluid viscosity very small.

3) A mathematical model for the fluidity of produced fluids in the heavy oil reservoirs of the Bohai Oilfield was established, which provided a basis for a clearer understanding of the produced fluid's flow state in different periods and different positions.

4) Based on the numerical simulation results of high-precision fitting reservoirs and detailed laboratory experimental data, a wellbottom flow temperature plate for Well-1 of heavy oil in Bohai Oilfield was established. The flow temperature and near-well reservoir temperature can be quickly estimated through the wellhead temperature data.

5) Viscosity plate of produced fluids from heavy oil reservoirs in Bohai Oilfield from the reservoir to the wellbore, flowing in the horizontal wellbore, and flowing in the tubing are established. According to the wellhead temperature, water content and temperature, the viscosity charts can be used to quickly obtain the viscosity of different CSS periods and different positions.

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