Experimental study on percolation mechanism and displacement characteristics of cold recovery in offshore heavy oil field

Ying-xian Liu¹ · Jie Tan¹ · Hui Cai¹ · Gong-chang Wang¹ · Song-ru Mou¹

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Abstract

The heavy oil reservoir is a special kind of oil and gas reservoir that differs from the conventional reservoir in many ways. Due to the high viscosity of crude oil, it is not easy to recover. When the viscosity of underground crude oil exceeds 150 cp, the land heavy oil field is generally developed by thermal recovery. S.Z. oilfield is a heavy oil reservoir in the Bohai Sea, with surface crude oil viscosity of 3000–25,000 cp and underground crude oil viscosity of 400–1000 cp. Limited by offshore equipment, the development strategy of land oilfields can't be directly applied. High production capacity is obtained through the cold production development of horizontal branch experimental wells, and the water drive production capacity can reach 40–70 m³/day. At present, there is a lack of research on cold recovery development under the viscosity of crude oil. The existing primary research and common knowledge are challenging to support efficient development technology for effectively producing heavy oil reservoirs. In this paper, through physical simulation experiments, the phase behavior and rheological properties of crude oil in the target block are studied, and the rheological properties of crude oil are clarified. Then, the depletion production and water flooding experiments are carried out, and the displacement characteristics and laws of water flooding cold production are analyzed. Finally, the indoor experiments of water flooding sweep efficiency and oil displacement efficiency in the target block are carried out. Clear its micro and macro spread. It provides technical support for the effective production of offshore heavy oil fields.

Keywords Offshore oilfield · Heavy oil · Cold recovery · Seepage mechanism · Displacement characteristics

Preface

Factors affecting cold heavy oil recovery

Heavy oil viscosity

The researchers' analysis shows that due to the viscosity anomaly of heavy oil, the oil recovery rate of the heavy oil reservoir is much lower than that of the reservoir without abnormal viscosity under seepage conditions because of the abnormal viscosity of heavy oil, which destroys Newton law and Darcy seepage law. In 1960, former Soviet scholar B. H. Sultanov proposed that crude oil belongs to non-Newtonian fluid, and many scholars at home and abroad have carried

out experiments and numerical studies (Mai and Kantzas 2009; Liu et al. 2013).

Through experiments, it is concluded that the underground seepage of heavy oil meets the seepage law of Bingham fluid in the non-Newtonian fluid. There is an initial pressure gradient in the seepage process, and its value is about 104 kPa/M. Although the concept of starting pressure is proposed in this paper, there is no quantitative study and description due to the difference of reservoir types in the study of the starting pressure gradient. In 1997, Huang Yanzhang and Bai Baojun deduced the expression of initial pressure gradient, respectively, based on experiments (Sheng et al. 1997; Adams 1982; Zheng and Yang 2013).

In the 1960s, non-Newtonian fluids were used in oil fields, such as polymer solution, micelle solution, foam liquid, and emulsion as oil displacement agents. These are non-Newtonian fluids. With the development of the global economy, the demand for oil in the world is increasing rapidly. The heavy oil resources attract the attention of the world with their abundant reserves. Therefore, people began to study

✉ Jie Tan
4687610@qq.com

¹ Bohai Petroleum Research Institute, Tianjin Branch of CNOOC Ltd., Tianjin, China

the characteristics and seepage law of heavy oil. Heavy oil, as a kind of non-Newtonian fluid, has its unique flow and rheological characteristics. Rheology refers to the deformation or flow of material or a material system under the force or force system, flow deformation. The equation describing the rheological behavior is called the constitutive equation or rheological equation of state. Non-Newtonian fluid can be divided into pure viscous and viscoelastic; pure viscous non-Newtonian fluid refers to any fluid that cannot be recovered after the shear force is removed, including pure viscous fluid independent of time. This fluid has pseudo-plasticity, expansibility, Bingham, quasi yield plasticity, and yield expansion. The time-related pure viscous fluid has thixotropic (thixotropic) and shock condensation (thixotropy). Viscoelastic non-Newtonian fluid is a fluid that can be partially recovered after the shear force is removed (Singhal 2009; Zheng 2015; Guo 2014; Zhang 2007).

Natural of porous media

Unlike conventional thin oil, heavy oil has a high viscosity, significant molecular weight, and strong polarity, and the interaction force between crude oil and rock interface and between crude oil is large, which leads to the seepage of heavy oil deviates from Darcy law. This kind of seepage has the starting pressure gradient non-Darcy seepage. When the driving pressure gradient exceeds the initial pressure gradient, the heavy oil could flow (Sun 2017; Li 2016; Yu 2017).

Different scholars have different viewpoints on the causes of the starting pressure gradient. There are three primary schools: fluid theory, media theory, and absorbing water theory. According to the fluid theory, the rheological behavior of non-Newtonian fluid is the leading cause of starting pressure gradient. The medium theory holds that the nature of porous medium would affect the interaction force between fluid and porous medium. The influence of this force would form a stable gel film on the surface of crude oil and porous medium so that the gelatin membrane partly covers the pores of rocks, and the flow of fluid in the rock must be destroyed—the reason for the starting pressure gradient. According to the theory of water absorption, there is a water absorption layer on the surface of medium particles, which would produce resistance to fluid flow. The flow of fluid in the medium needs to overcome this resistance, which is why the generation of starting pressure gradient (Zheng 2013; Cheng 2020).

Alvaro praday has conducted single-phase experimental seepage research on artificially cemented cores and natural cores with different permeability. It is obtained that under low-speed seepage, the seepage curve presents a nonlinear relationship with the increase in seepage speed, the seepage curve transitions to a linear section. The same liquid shows different seepage characteristics in different media, which

fully shows that the pore structure characteristics of porous media have an important influence on the seepage velocity of low-speed non-Darcy flow (Wang 2015; Yan et al. 2015).

History of the previous studies and field applications

At present, the development of similar heavy oil reservoirs mainly adopts thermal production development, and there are few examples of cold production development results. Some heavy oil fields in Canada have achieved good development results through injection and production.

The viscosity of underground crude oil in the Niuxintuo oilfield is above 400 cp (65 °C). The comparison of data before and after cold production shows that the oil production volume of the well increases 148.1 m³/day and the oil production by 1.1 m³/day (Zhao 2019; Zhang 2017).

The permeability of the Chenjiazhuang oilfield is 2500 mD, the viscosity of surface degassing crude oil (50 °C) is 10,000–30,000 cp, and that of crude oil in formation is generally 400–800 cp. According to the physical properties of crude oil, the main production processes adopted are high-pressure filling sand control and electric heating rod pumping heavy oil, with a heating power of 50–70 KW. The lifting process adopts 12 beam pumping and 57 mm long barrel pumps, and the operating parameters are 4.2 m×0.5~2 r/min. The daily oil output is 5.4 m³ (Li 2014; Shi 2013).

The permeability of the Gudao oilfield is 1465 mD, and the viscosity of surface crude oil is 3300–5500 cp. Water injection is developed. The thin and single reservoirs and the viscosity of crude oil is significant. The development effect is poor. Therefore, it is adjusted to thermal production development, with a daily liquid production level of 2766 m³/day, unit oil production level of 207 m³/day, average single well daily production capacity of 86 m³/day, single well daily oil production capacity of 6.3 m³/day, extended water cut of 94.5%, and cumulative oil production of 147×10⁴ m³, cumulative water yield 1220×10⁴ m³, cumulative water injection 1274×10⁴ m³, recovery degree 18.7%, recovery 25.0%, oil recovery rate 1.0% (Wu 2007; Qu 2014).

The permeability of Lukeqin heavy oil field in Xinjiang is 98.7–493 mD, the viscosity of underground crude oil is 150–500 cp, and the water drive viscosity is seriously pointed in, and the output is 4m³/day. After nitrogen foam flooding, the average single well increased oil production by 252 m³. In the same year, the cumulative oil increased by 11,573 m³, the oil changing rate was 0.8 m³/100 m³, and the input–output ratio was 1:1.1. Therefore, it is estimated that the average cumulative increase of oil in the single well is 406 m³ in the effective period. Through the statistical relationship between daily oil increase and water cut before huff and puff in the initial stage of a single well, it is found that

the higher the water content is, the more oil increases in the initial stage, the higher the water content and the higher the water cut indicates that the formation pressure is good. Thus, the plugging water mechanism can be entirely played (Wei 2010; Liu 2008).

WTG heavy oil field has a core permeability of 80.8–129.4 mD. The surface viscosity is 2000 cp, and the viscosity of underground crude oil is 500 cp. In the initial injection production and development stage, the daily oil production gradually decreases with the continuous production of production wells. As a result, the increase in cumulative oil production shows a decreasing trend, and the water content shows a gradual upward trend (Tong 2017; Fan et al. 2006).

Scholars have pointed out that the exchange of production wells with injection wells may help oil recovery. This production adjustment mode is called reverse water flooding. Some related experimental results show that when the water content of a heavy oil reservoir reaches a certain extent, the sweep coefficient of injected water can be expanded by adopting the reverse water flooding scheme, and the recovery rate of the reservoir can be further improved. After adopting the reverse water flooding, the sweep coefficient of the injected water in the oilfield has been improved to some extent, and the displacement effect of the water flooding is improved. As a result, the cumulative oil production increased by $0.42 \times 10^4 \text{ m}^3$ at the end of the forecast period, and the recovery degree increased by 0.33% (Dun et al. 1996).

Mendes et al. conducted a study in the Boskan oilfield in the west of Lake Malakaibo. The reservoir depth is more than 2400 m, the API value is 10.5, and the viscosity is between 150 and 350 cp. It is found that the secondary recovery of the reservoir is improved by using reverse seven-point well network water injection (Zhang et al. 1999; Liu 1999).

The Aberfeldy reservoir, big gully North oilfield, golden lake/Maidstone oilfield, tangled flags oilfield, wilder oilfield, Lloydminster oilfield, and soda lake oilfield in Canada were investigated. These oilfields are heavy oil reservoirs, with burial depth of 400–800 m, the permeability of 100–10,000 mD, dead oil viscosity of 800–80,000 cp, reservoir thickness of 3.5–7 m, and recovery degree failure exploitation of 0.1–1.8%. The horizontal well length of water injection development is 800–2000 m, the well spacing is 50–210 m, and the water injection development production is between 3 and 10 m³/day. After 0.5PV water is injected into the horizontal well, the recovery degree is 4–12%, and the expected recovery degree is 5–15% when 1 pv is injected. Thus, the recovery of water flooding can be increased by 0.4–19.7%, with an average of 8.5% (Qu 2013).

The heavy oil reservoir is a special kind of oil and gas reservoir that differs from conventional reservoirs in many ways.

Due to the high viscosity of crude oil, it is not easy to recover. When the viscosity of underground crude oil exceeds 150 cp, the land heavy oil field is generally developed by thermal recovery. S.Z. oilfield is a heavy oil reservoir in the Bohai Sea, with surface crude oil viscosity of 3000–25,000 cp and underground crude oil viscosity of 400–1000 cp. Limited by offshore equipment, the development strategy of land oilfields cannot be directly applied. Some scholars have explored the mechanism of heavy oil seepage, but the research is not systematic and in-depth. Some scholars have studied the mechanism of heavy oil seepage, but the research is not systematic and in-depth. In particular, the research on cold recovery development under the crude oil viscosity is relatively scarce, and the existing primary research and common understanding are challenging to support the establishment of efficient development technology for effectively producing heavy oil reservoirs. In this paper, physical simulation experiments are used to carry out depletion production and water displacement experiments, analyze the displacement characteristics and laws of water drive cold production and conduct indoor experiments on water drive sweep coefficient and oil displacement efficiency in the target block. Clarify its micro and macro spread. Provide technical support for effective production of heavy oil.

Reservoir physical properties and fluid properties

The S.Z. oilfield is a heavy oil reservoir in the Bohai Sea. It is a structural reservoir, delta sedimentary facies, depth – 1450 m, high porosity and permeability, and a normal temperature and pressure system. The viscosity of surface crude oil is as high as 3000–25,000 cp, and that of underground crude oil is 400–1000 cp (Table 1).

Viscosity test, viscosity-temperature test, and rheological properties of heavy oil

In this chapter, the PVT characteristics, viscosity-temperature characteristics, and rheological characteristics of crude oil are tested using oil samples from heavy oil reservoirs, and the effects of natural gas solubility, temperature, and shear rate on crude oil viscosity under different pressures are clarified.

PVT test of formation crude oil

Bubble point pressure test method

Experimental material: Degassed crude oil; petroleum ether; absolute ethanol; toluene.

Experimental instrument: Ultra-high pressure full visual PVT test system, produced in France, model PVT 250/1500 FV, as shown in Fig. 1. The maximum working

Table 1 Table of oilfield physical properties and fluid properties

Oilfield name	Reservoir type	Sedimentary facies	Rock type	Reservoir depth (m)	Porosity (%)	Permeability (mD)	Original formation pressure (MPa)	GOR (m^3/m^3)	Formation temperature ($^{\circ}\text{C}$)	Formation crude oil viscosity (65 $^{\circ}\text{C}$, 15 MPa), cp	Surface crude oil viscosity (20 $^{\circ}\text{C}$, Atmospheric pressure), cp
S.Z	Structural reservoir	Delta	Sandstone	~ 1450	40–46	2500–3000	15	2–16 (Average is 4)	65	400–1000	3000–25,000

pressure of the instrument is 150 MPa, and the maximum working temperature is 200 $^{\circ}\text{C}$. It can test the temperature, pressure, and volume of different fluids under high temperature and high pressure and analyze the data. The device has a visual window, which can observe fluid state in a PVT cylinder in real-time.

Experimental purpose: Prepare the degassed crude oil and simulated gas into gas-bearing formation crude oil according to the production GOR, analyze the phase characteristics of crude oil under high temperature and high pressure, and clarify the physical properties of crude oil.

Experiment content

1. Preparation of gas-bearing crude oil in formation;
2. Single degassing experiment: test the GOR;
3. Constant mass expansion test: original GOR, dew point pressure, and P–V relationship;

Experiment steps

1. Check the tightness of the PVT kettle body. After ensuring good sealing, inject 40 mL of dehydrated crude oil into the PVT drum, and inject the required gas volume according to the GOR of 2:1.
2. Set the instrument temperature to 65 $^{\circ}\text{C}$ and place it for more than 4H to make the fluid in the PVT cylinder reach the formation temperature.
3. At 65 $^{\circ}\text{C}$, slowly increase the pressure in the cylinder and reduce the cavity to increase the volume of crude oil by 1–2 MPa each time. During the pressure rise, turn on the mixing function to thoroughly mix the gas and crude oil until the formation pressure reaches 15 MPa.
4. Depressurize by withdrawing the pump. During the depressurization process, the instrument can collect the temperature, pressure, and volume in real-time. The depressurization speed is 3 mL/h. The mixing function is turned off during the depressurization process.
5. Through the computer connected with the PVT instrument, the relationship curve between pressure and crude oil volume is directly drawn, and the relationship curve between volume and pressure is drawn on the coordinate axis. The change of volume and pressure should be two straight lines with different slopes, and the intersection is the bubble point pressure.
6. Repeat step (3) to remix the gas and oil in the PVT cylinder, gradually depressurize at the rate of 6 mL/h and process the data according to (5).
7. Repeat step (3), depressurize 1 MPa each time according to the balanced depressurization method, turn on the mixing function at the same time, keep the phase balance of the liquid in the cylinder, record the volume, and process the data according to (5).

Fig. 1 Ultra-high pressure full visual PVT test system

8. The GOR was changed to 4, 8, 12, and 16, and the (2)–(7) experiment was repeated.

Bubble point pressure test results

When the GOR is 2, the phase state change results of crude oil are shown in Fig. 2.

It can be seen from Fig. 2 that when the volume increases, the pressure first decreases rapidly and then decreases slowly. When the pressure is high, the fluid is in the liquid phase, the compressibility coefficient is small, and the pressure changes obviously with the volume. When the pressure drops to a specific value, the fluid becomes gas–liquid two-phase, the compression coefficient increases, and the pressure does not change obviously with the volume. At the same time, it can be seen that the curves of the three different depressurization modes do not wholly coincide. The bubble point pressure measured by balanced depressurization is 1.23 MPa, the bubble point pressure measured by rapid depressurization is 0.68 MPa, and the bubble point pressure measured by slow depressurization is 1.12 MPa. The faster the depressurization rate is, the gas dissolved in the crude oil would not have time to escape but exists in the crude oil in the form of bubbles, as shown in Fig. 3. Only when the pressure decreases to a certain value, the bubbles would escape forming gas. Therefore, the faster the pressure reduction speed is, the lower the bubble point pressure is.

When the GOR is 4, the phase state change results of crude oil are shown in Fig. 4.

It can be seen from Fig. 4 that when the volume increases, the pressure first decreases rapidly and then decreases slowly. When the pressure is high, the fluid is in the liquid

Fig. 2 Crude oil P–V curve with GOR of 2

phase, the compressibility coefficient is small, and the pressure changes obviously with the volume. When the pressure drops to a certain value, the fluid becomes gas–liquid two-phase, the compression coefficient increases, and the pressure does not change obviously with the volume. At the same time, it can be seen that the curves of the three different depressurization modes do not wholly coincide. The bubble point pressure measured by balanced depressurization is 3.54 MPa, the bubble point pressure measured by rapid depressurization is 2.18 MPa, and the bubble point pressure measured by slow depressurization is 3.05 MPa. The faster the depressurization speed is, the lower the bubble point pressure is.

Fig. 3 Rapid depressurization liquid state of crude oil when GOR is 2

Fig. 5 Crude oil P-V curve when GOR is 8

Fig. 4 P-V curve of crude oil when GOR is 4

When the GOR is 8, the phase state change results of crude oil are shown in Fig. 5.

As shown in Fig. 5, when the volume increases, the pressure first decreases rapidly and then decreases slowly. When the pressure is high, the fluid is in the liquid phase, the compressibility coefficient is small, and the pressure changes obviously with the volume. When the pressure drops to a certain value, the fluid becomes gas-liquid two-phase, the compression coefficient increases, and the pressure does not change obviously with the volume. At the same time, it can be seen that the curves of the three different depressurization methods do not entirely coincide. The bubble point pressure measured by balanced depressurization is 5.15 MPa, the bubble point pressure measured by rapid depressurization is 3.63 MPa, and the bubble point pressure measured by slow depressurization

Fig. 6 P-V curve of crude oil when GOR is 12

is 4.65 MPa. The faster the depressurization speed is, the lower the bubble point pressure is.

When the GOR is 12, the phase state change results of crude oil are shown in Fig. 6.

It can be seen from Fig. 6 that when the volume increases, the pressure first decreases rapidly and then decreases slowly. When the pressure is high, the fluid is in the liquid phase, the compressibility coefficient is small, and the pressure changes obviously with the volume. When the pressure drops to a certain value, the fluid becomes gas-liquid two-phase, the compression coefficient increases, and the pressure does not change obviously with the volume. At the same time, it can be seen

that the curves of the three different depressurization modes do not wholly coincide. The bubble point pressure measured by balanced depressurization is 6.02 MPa, the bubble point pressure measured by rapid depressurization is 5.44 MPa, and the bubble point pressure measured by slow depressurization is 5.71 MPa. The faster the depressurization speed is, the lower the bubble point pressure is.

When the GOR is 16, the phase state change results of crude oil are shown in Fig. 7.

It can be seen from Fig. 7 that when the volume increases, the pressure first decreases rapidly and then decreases slowly. When the pressure is high, the fluid is in the liquid phase, the compressibility coefficient is small, and the pressure changes obviously with the volume. When the pressure drops to a certain value, the fluid becomes gas–liquid two-phase, the compression coefficient increases, and the pressure does not change obviously with the volume. At the same time, it can be seen that the curves of the three different depressurization modes do not wholly coincide. The bubble point pressure measured by balanced depressurization is 8.12 MPa, the bubble point pressure measured by rapid depressurization is 6.81 MPa, and the bubble point pressure measured by slow depressurization is 7.49 MPa. The faster the depressurization speed is, the lower the bubble point pressure is.

Figure 8 shows the solubility of the gas in crude oil under different pressures. It can be seen that the solubility of natural gas increases with the increase in pressure, which is approximately linear.

Fig. 7 P–V curve of crude oil with GOR of 16

Summary

According to the bubble point pressure experiment results, the larger the gas–oil ratio is, the greater the bubble point pressure is (see Table 2). The more dissolved gas, the greater the pressure required and the corresponding bubble point pressure. The faster the depressurization rate is, the gas dissolved in the crude oil would not have time to escape but exists in the crude oil in the form of bubbles. Only when the pressure decreases to a certain value, the bubbles would escape forming gas. Therefore, the faster the pressure reduction speed is, the lower the bubble point pressure is, as shown in Table 2. The faster the depressurization rate, the gas dissolved in the crude oil has no time to escape but exists in the crude oil in the form of bubbles. Only when the pressure decreases to a specific value, the bubbles would escape forming gas.

Crude oil viscosity measurement

Experimental instrument: falling ball viscometer, as shown in Fig. 9.

Fig. 8 Solubility curve of gas in crude oil

Table 2 Bubble point pressure under different pressure drop modes

Mode of pressure drop	Bubble point pressure				
	GOR 2	GOR 4	GOR 8	GOR 12	GOR 16
Balanced depressurization	1.23	3.54	5.15	6.02	8.12
Rapid depressurization	0.69	2.18	3.63	5.44	6.81
Slow depressurization	1.12	3.05	4.65	5.71	7.49

Fig. 9 Falling ball viscometer

Experimental steps:

1. Transfer the standard solution GBW13608 to the standard tube of the falling ball viscometer, the temperature is 20 °C, and the experimental angle is 90°;
2. Turn the falling ball viscometer so that the end (upper part) with the valve faces down, press the "ball suction" switch to make the steel ball suck onto the upper magnet;
3. Rotate the falling ball viscometer so that its upper part faces down and is fixed at a certain angle. Press the "drop ball" switch, the steel ball begins to fall, and the timing starts simultaneously. When the steel ball falls to the bottom, it would automatically stop timing and record the falling time of the steel ball. Repeat more than 3 times until the measured time is the same;
4. Replace standard solutions GBW13609 and GBW13611, repeat (2)~(3);
5. Take the viscosity value of the three standard solutions as the ordinate ($\rho_{ball} - \rho_{liquid}$) t is the abscissa, draw the points of each angle in the coordinate system, and the slope is the viscometer constant K;
6. After the oil sample is prepared according to the GOR of 4, transfer it to the standard tube of the falling ball viscometer, control the pressure at 15 MPa, repeat (2)–(3), and measure the viscosity at 65 °C, 75 °C, 85 °C, 95 °C and 105 °C, respectively;
7. Change the GOR to 8 and 16 and repeat the experiment (5).

Table 3 Standard solution parameters

Name of standard solution	Temperature (°C)	Angle (°)	Dynamic viscosity (mPa s)	Density (cm ³)
GBW13608	20	90	538.34	0.9726
GBW13609	20	90	955.21	0.9729
GBW13611	20	90	4827.50	0.9715

Experimental result

The parameters of the standard solution used in the experiment are shown in Table 3. The calibration results are shown in Fig. 10. It can be seen that after calibration with the standard solution, the calibration curve is approximately a straight line. When the falling angle of the falling ball viscometer is 90°, the viscometer constant of the curve is 1.4676.

The variation of crude oil with GOR and temperature is shown in Fig. 11. It can be seen from Fig. 11 that under the same GOR, the crude oil viscosity first decreases rapidly with the increase in temperature and then decreases slowly when the temperature is higher than 85 °C, indicating that the crude oil viscosity is sensitive to temperature. At the same temperature, the crude oil viscosity decreases with the increase in GOR.

The experiment shows bubbles in crude oil, showing the "foam oil" phenomenon, as shown in Fig. 12.

Fig. 10 Calibration curve of standard solution

Fig. 11 Variation curve of crude oil viscosity with temperature

Viscosity-temperature test

Experimental material: Degassed crude oil.

Experiment method

1. Put a certain volume of crude oil into the crude oil electric dehydrator, as shown in Fig. 13, set the temperature of the dehydrator to 105 °C and dehydrate for 24 h;
2. Take a certain amount of dehydrated crude oil and put it into the MCR302 ANTONPA rheometer. As shown in Fig. 14, heat the crude oil to the target experimental temperature and measure the crude oil viscosity at different shear rates;

3. Change the temperature and measure the crude oil viscosity at different temperatures. The temperature range is 40–110 °C.

Experiment result

The viscosity of dehydrated crude oil at different temperatures and shear rates is measured, and the results are shown in Figs. 15 and 16.

It can be seen from Fig. 15 that at the same temperature, the viscosity of crude oil decreases with the increase in shear rate, showing the characteristics of shear thinning. At the formation temperature of 65 °C, with the increase in shear rate, the crude oil viscosity decreases from 3250 to 1660 cp. Figure 16 shows the crude oil viscosity at different temperatures at the same shear rate. It can be seen that the crude oil viscosity first decreases rapidly with the increase in temperature, from 9340 to 724 cp. When the temperature is higher than 80 °C, the reduction range of crude oil viscosity decreases.

Rheological test

Experimental materials: Degassed crude oil, methane, and ethane.

Experimental instruments: High temperature and high-pressure capillary viscosity measuring device and crude oil sampler, as shown in Fig. 17.

Experimental Objective: Analyze the viscosity characteristics of heavy oil at different temperatures and pressures and determine its influencing factors.

Experiment content

1. Crude oil viscosity at different temperatures;
2. Viscosity of crude oil at different shear rates;
3. Crude oil viscosity under different dissolved GOR.

Prepare live oil according to the GOR. The test steps of live oil viscosity are as follows:

1. Prepare live oil under a certain saturation pressure;
2. Set the temperature of the incubator to the test temperature (65 °C), keep it constant for 4 h, and place the prepared live oil in the sample cylinder;
3. Adjust the pressure of the backpressure valve to the saturation pressure, set the pump flow rate to 0.2 mL/min and 0.5 mL/min, respectively, test the stable differential pressure at both ends of the capillary at different temperatures (65 °C, 75 °C, 85 °C, 95 °C, and 105 °C) from low to high, measure the gas content in the crude oil and accurately measure the GOR;
4. Prepare live oil under different saturation pressures and repeat steps (2) and (3) to obtain the relationship

Fig. 12 Foam oil phenomenon photos

Fig. 13 Crude oil dehydrator

between capillary stable differential pressure and flow rate to obtain the viscosity of live oil.

In the degassing crude oil rheology experiment, the thermostat's temperature is set to the test temperature and constant temperature 4 h. The degassing crude oil is used as the oil sample tube; then, the pressure of the return valve is adjusted to the test pressure. The relationship between the capillary pressure and the flow rate under different flow rates (1 mL/min, 2 mL/min, 3 mL/min, 4 mL/min) and pressure is tested, and the viscosity of degassing crude oil is obtained.

Fig. 14 MCR302 ANTONPA rheometer

Experiment results

Through the thin tube viscosity measuring device, the change of crude oil viscosity measured when the GOR is 4 is shown in Fig. 18.

It can be seen from Fig. 18 that when the GOR is 4, the speed is 0.2 mL/min, the viscosity is between 3540 and 991 cp, the speed is 0.5 mL/min, the viscosity is between 2815 and 226 cp, the temperature increases, the viscosity decreases, the shear rate increases, the viscosity decreases, the temperature is higher than about 85 °C, and the decreasing amplitude of viscosity decreases with the increase in temperature.

Fig. 15 Viscosity-temperature curve of crude oil

Fig. 16 Variation of crude oil viscosity with temperature

Through the thin tube viscosity measuring device, the change of crude oil viscosity measured when the GOR is 6 is shown in Fig. 19.

It can be seen from Fig. 16 that when the GOR is 6, the speed is 0.2 mL/min, the viscosity is between 3369 and 240 cp, the speed is 0.5 mL/min, the viscosity is between 2768 and 140 cp, the temperature increases, the viscosity decreases, the shear rate increases, the viscosity decreases, the temperature is higher than about 85 °C, and the decreased amplitude of viscosity decreases with the increase in temperature.

Through the thin tube viscosity measuring device, the change of crude oil viscosity measured when the GOR is 12 is shown in Fig. 20.

As shown in Fig. 20, when the GOR is 12, the speed is 0.2 mL/min. The viscosity is between 2719 and 220 cp.

The speed is 0.5 mL/min. The viscosity is between 1647 and 126 cp, the temperature increases, the viscosity decreases, the shear rate increases, and the viscosity decreases. When the temperature is higher than 85 °C, the viscosity decreases with the increase in temperature.

Figure 21 shows the viscosity of degassed crude oil and crude oil with the GOR of 30 under different shear rates. The viscosity of gas containing crude oil is 258–377 cp, significantly lower than that of degassed crude oil under the same conditions.

Summary

The viscosity-temperature test shows that the viscosity of crude oil decreases with the increase in shear rate at the same temperature, showing the characteristics of shear thinning. With the increase in temperature, the crude oil viscosity first decreases rapidly. When the temperature is higher than 80 °C, the decrease range of crude oil viscosity decreases.

Core seepage characteristic test

Experimental materials: Degassed crude oil, methane, and ethane; Quartz sand.

Experiment method

By measuring the pressure difference of stable seepage of crude oil in sand-filled pipe, the seepage characteristics of crude oil are analyzed. The main experimental steps are as follows:

1. Wash the two cores sampled on-site, as shown in Fig. 22. Measure the basic parameters after oil washing, as shown in Table 4. Then measure the water permeability and gas permeability, respectively, and the results are shown in Tables 5 and 6. It can be seen that the gas logging permeability is 2–3 times that of the liquid logging permeability, and the formation gas logging permeability is 3000 mD, so the liquid logging permeability of the sand filling pipe should be 1000–1500 mD.
2. Wash the formation sand. The comparison before and after oil washing is shown in Fig. 23. The laser particle size analyzer is used for particle size analysis. The analysis results are shown in Table 7.
3. Fill the sand filling the pipe with the particle size combination shown in Table 7, and then vacuum the saturated kerosene to determine the porosity and permeability.
4. Inject the crude oil into the sand filling pipe. Keep the backpressure higher than the bubble point pressure to avoid crude oil degassing during the injection process.

Fig. 17 High temperature and high-pressure capillary viscosity measuring device

Fig. 18 Viscosity of crude oil with GOR of 4

Measure the outlet GOR. When the outlet GOR is equal to the GOR of the injected crude oil, continue to inject 1PV.

- The temperature is set at 65 °C. After the sand filling pipe is aged 24 h, set different injection speeds and conduct a seepage experiment. After each injection speed is stable, measure the differential pressure at both ends of the sand filling pipe, and proceed to the next speed.

Fig. 19 Viscosity of crude oil with GOR of 6

- Draw the relationship curve between differential pressure and injection velocity, and analyze the characteristics of crude oil seepage.

Experiment result

The percolation characteristics of formation crude oil at different temperatures are tested.

(1) Seepage characteristics at 65 °C

The seepage characteristics at the formation temperature of 65 °C are shown in Fig. 24. It can be seen that when the

Fig. 20 Viscosity of crude oil with GOR of 12

Fig. 21 Viscosity of degassed crude oil and crude oil with GOR of 30 under different shear rates

Fig. 22 Core 1 (left), core 2 (right)

pressure gradient is small, the seepage velocity increases slowly with the increase in the pressure gradient. A curve relationship between seepage velocity and pressure gradient indicates that oil seepage would occur under a small pressure gradient. However, in this case, the seepage velocity is much smaller than that under Darcy's law. With the increase in pressure gradient, the seepage velocity also increases. When the pressure gradient reaches a certain value, the seepage velocity and pressure gradient gradually become linear.

Figure 24 shows the relationship between viscosity and flow rate. It can be seen that with the increase in flow rate, the viscosity decreases from 1125 to 349 cp, first decreases rapidly and then tends to be flat, which is approximately a power function, showing the characteristics of shear thinning. When the output of well c44h1 is 50–70 m³/day, according to Fig. 24, the viscosity is 600–730 cp.

(2) Seepage characteristics at 95 °C

The seepage characteristics at the formation temperature of 95 °C are shown in Fig. 25.

It can be seen that similar to the results at 65 °C, when the pressure gradient is small, the seepage velocity increases slowly with the pressure gradient increase. The relationship between the seepage velocity and the pressure gradient is a curve of the concave velocity axis, which indicates that oil seepage would occur under a small pressure gradient. However, in this case, the seepage velocity is much smaller than that under Darcy's law. With the increase in pressure gradient, the seepage velocity also increases. When the pressure gradient reaches a certain value, the seepage velocity and pressure gradient gradually become linear.

Figure 25 shows the relationship between viscosity and flow rate. It can be seen that with the increase in flow rate, the viscosity decreases from 450 to 112 cp, which is approximately a power function, showing the characteristics of shear thinning. At the same time, the viscosity at 95 °C is lower than that at 65 °C.

(3) Seepage characteristics at 110 °C

The seepage characteristics at formation temperature of 110 °C are shown in Fig. 26. It can be seen that the relationship between velocity and pressure gradient is approximately linear, and the characteristics of non-Newtonian fluid are not prominent.

From Fig. 26, the crude oil viscosity first decreases rapidly with speed and then tends to be flat, ranging from 45 to 135 cp.

Table 4 Basic parameters of rock samples

Sample no	Radius (mm)	High (mm)	Cross-sectional area (mm ²)	Volume (mm ³)	Quality (before oil washing) (g)	Quality (after oil washing) (g)	Quality (saturated water) (g)	Porosity (%)
Core 1	25.16	50.92	496.96	25,303.43	50.44	47.86	54.99	28.18
Core 2	25.38	55.60	505.65	28,114.33	54.11	50.78	59.26	30.20

Table 5 Results of liquid permeability of core 1

Permeability (mD)	1	2	3	Average value
Liquid permeability	243	284	244	257
Gas permeability	562	541	562	555

Table 6 Liquid permeability test results of core 2

Permeability (mD)	1	2	3	Average value
Liquid permeability	305	343	366	338
Gas permeability	916	959	930	935

Fig. 23 Comparison of formation sand before (upper) and after (lower) oil washing**Table 7** Sand ratio for sand filling pipe

Mesh number	40–80	80–120	120–180
Proportion (%)	65	20	15

(4) Seepage characteristics at 55 °C

The relationship between flow rate and pressure gradient at 55 °C is shown in Fig. 27. Within the range of experimental flow rate, the relationship between flow rate and pressure

gradient is approximately linear. The viscosity at this temperature is shown in Fig. 33. The viscosity first decreases rapidly and then decreases slowly with the increase in flow rate. When the production of well c44h1 is 50–70 m³/day, the viscosity is 2400–3400 cp, according to Fig. 33.

According to the above experimental results, the relationship between crude oil viscosity and flow rate is approximately a power function at the same temperature. With the flow rate increase, the crude oil viscosity first decreases rapidly and then tends to be stable. With the increase in temperature, the viscosity of crude oil decreases, and the non-Newtonian characteristics weaken.

Table 8 shows the relationship between crude oil viscosity and seepage velocity at different temperatures.

Summary

The percolation experiment of crude oil core shows that when the temperature is 65 °C and 95 °C, and the pressure gradient is small, the percolation velocity increases slowly with the increase in pressure gradient, and the relationship between percolation velocity and pressure gradient is a curve of concave velocity axis. With the increase in pressure gradient, the seepage velocity increases. When the pressure gradient reaches a certain value, the seepage velocity and pressure gradient gradually become linear. When the temperature is 110 °C, the seepage velocity is approximately linear with the pressure gradient. With the increase in seepage velocity, the crude oil viscosity first decreases rapidly and then tends to be flat, forming a power function relationship. The crude oil viscosity ranges from 600 to 730 cp at the formation temperature of 65 °C.

Summary of crude oil properties

1. The crude oil PVT experiment shows that the bubble point pressure is related to the pressure drop speed. The faster the pressure drop, the lower the bubble point pressure, showing the characteristics of the foaming oil, and the foam oil phenomenon is observed in the PVT tube. The bubble point pressure of crude oil under formation conditions is 3.54 MPa.

Fig. 24 Seepage characteristics at 65 °C

Fig. 25 Seepage characteristics at 95 °C

2. The falling ball viscometer experiment shows that the higher the GOR of crude oil, the lower the crude oil viscosity. When the GOR is greater than 9, the viscosity decreases slowly. The viscosity of crude oil is sensitive to temperature and decreases rapidly with the

- increase in temperature. When it is higher than 85 °C, the decrease range decreases. The temperature rises from 65 to 105 °C, and the viscosity of crude oil under formation conditions decreases from 7732.22 to 1188.46 cp.
3. The viscosity-temperature test shows that the viscosity of crude oil decreases with the increase in shear rate

Fig. 26 Seepage characteristics at 110 °C

Fig. 27 Seepage characteristics at 55 °C

Table 8 Relationship between crude oil viscosity and flow rate

Temperature (°C)	Expression	Correlation coefficient
65	$\mu = 107.08 V^{-0.25}$	0.9045
95	$\mu = 24.482 V^{-0.305}$	0.9872
110	$\mu = 19.23 V^{-0.29}$	0.9159

at the same temperature, showing the characteristics of shear thinning. With the increase in temperature, the crude oil viscosity first decreases rapidly. When the temperature is higher than 80 °C, the decrease range of crude oil viscosity decreases.

- The capillary viscosity experiment shows that when the GOR of crude oil is 4, and the flow rate is 0.2 mL/min, the crude oil viscosity is 3540–991 cp. The viscosity of crude oil is between 2815 and 226 cp at the flow rate of 0.5 mL/min. With the increase in temperature, the viscosity decreases, the shear rate increases and the viscosity decreases.
- The percolation experiment of crude oil core shows that when the temperature is 65 °C and 95 °C, and the pres-

sure gradient is small, the percolation velocity increases slowly with the increase in pressure gradient, and the relationship between percolation velocity and pressure gradient is a curve of concave velocity axis. With the increase in pressure gradient, the seepage velocity increases. When the pressure gradient reaches a certain value, the seepage velocity and pressure gradient gradually become linear. When the temperature is 110 °C, the

Fig. 28 High temperature and high-pressure displacement equipment

seepage velocity is approximately linear with the pressure gradient.

- The percolation experiment of crude oil core shows that the crude oil viscosity first decreases rapidly with the increase in percolation velocity and then tends to be flat, forming a power function relationship. The crude oil viscosity ranges from 600 to 730 cp at the formation temperature of 65 °C.

Depletion mining experiment

Experimental methods

Experimental instrument: High temperature and high-pressure displacement equipment, as shown in Fig. 28.

Experimental materials: Degassed crude oil, methane, and ethane; Quartz sand.

Experimental objective: Analyze the depletion production characteristics of heavy oil under different conditions and clarify the oil and gas production characteristics and influencing factors of depletion production.

Experiment steps

- According to the bubble point pressure, temperature (65 °C) and dissolved gas-oil ratio, the live oil was compounded;
- The volume of saturated water is the pore volume, and the porosity is the ratio of pore volume to the volume of the sand filling pipe. The temperature of the incubator is 65 °C;
- Connect the displacement device and inject water, measure the pressure difference at both ends of the sand filling pipe under different flow steady states, calculate the permeability of the sand filling pipe, and ensure that the

a. 5 MPa/h depletion production curve

b. 5 MPa/h depletion recovery gas-oil ratio and recovery degree curve

Fig. 29 5 MPa/h depletion mining curve

permeability of the sand filling pipe is in the range of 1000–1800 mD;

- The core is saturated with live oil, the backpressure is set at 15 MPa, the initial oil saturation is calculated according to the produced water, and the core is aged for 24 h under the formation temperature;
- According to the set pressure drop rate (5 MPa/h, 7.5 MPa/h, 15 MPa/h), gradually reduce the backpressure, and record the variation of oil production and gas production with pressure in the process of depletion development;
- Analysis of oil and gas production data, evident production characteristics under different conditions, and analysis of depletion production factors.

Experimental result

The experiments under different depletion mining rates (5 MPa/h, 7.5 MPa/h, 15 MPa/h) were carried out through the sand filling pipe experiment.

5 MPa/h speed depletion mining

The permeability of the sand filling pipe is 1315 mD, the dripping water is 45 mL, the porosity is 45.9%, the saturated oil is 40 mL, the oil saturation is 0.89, and the temperature of the incubator is 65 °C. When the depletion production is carried out at the speed of 5 MPa/h, the experimental results are shown in Fig. 29.

It can be seen from Fig. 29 that when the pressure is higher than the bubble point, the oil output is smaller, and the cumulative oil production increases slowly. When the pressure is lower than the bubble point, the oil output increases and the cumulative oil production increases faster. When the pressure continues to decrease, the oil output gradually decreases. When the pressure is higher than the bubble point, the gas-oil ratio remains relatively stable. When the pressure is lower than the bubble point, the gas-oil ratio

fluctuates slightly, the pressure continues to decrease, and the gas-oil ratio increases rapidly 38%.

5 MPa/h speed depletion mining

The permeability of the sand filling pipe is 1233 mD, the dripping water is 43 mL, the porosity is 43.8%, the saturated oil is 37 mL, the oil saturation is 0.86, and the temperature of the incubator is 65 °C. When the depletion production is carried out at the speed of 7.5 MPa/h, the experimental results are shown in Fig. 30.

It can be seen from Fig. 30 that when the pressure is higher than the bubble point, the oil output is smaller, and the cumulative oil production increases slowly. When the pressure is lower than the bubble point, the oil output increases and the cumulative oil production increases faster. When the pressure continues to decrease, the oil output gradually decreases. When the pressure is higher than the bubble point, the gas-oil ratio remains relatively stable. When the

a. 7.5MPa/h depletion production curve

a. 15MPa/h depletion production curve

b. 7.5MPa/h depletion recovery gas-oil ratio and recovery degree curve

b. 15MPa/h depletion recovery gas-oil ratio and recovery degree curve

Fig. 30 7.5 MPa/h depletion mining curve

Fig. 31 15 MPa/h depletion mining curve

pressure is lower than the bubble point, the gas–oil ratio fluctuates slightly, the pressure continues to decrease, and the gas–oil ratio increases rapidly 32%.

15 MPa/h speed depletion mining

The permeability of the sand filling pipe is 1287 mD, the dripping water is 40 mL, the porosity is 40.8%, the saturated oil is 36 mL, the oil saturation is 0.90, and the temperature of the incubator is 65 °C. When the depletion production is carried out at the speed of 15 MPa/h, the experimental results are shown in Fig. 31.

It can be seen from Fig. 31 that when the pressure is higher than the bubble point, the oil output is smaller, and the cumulative oil production increases slowly. When the pressure is lower than the bubble point, the oil output increases and the cumulative oil production increases faster. When the pressure continues to decrease, the oil output gradually decreases. When the pressure is higher than the bubble point, the gas–oil ratio remains relatively stable. When the pressure is lower than the bubble point, the gas–oil ratio fluctuates slightly, the pressure continues to decrease, and the gas–oil ratio increases rapidly 80%.

Summary

It can be seen from the above experiments that when the pressure is higher than the bubble point, less oil is produced; when the pressure is lower than the bubble point, more oil is produced, and most of the crude oil is produced below the bubble point pressure. When the pressure is higher than the bubble point pressure, the crude oil is single-phase, and the compressibility is slight. The crude oil is produced by decompression and expansion. When the pressure is lower than the bubble point pressure, the dissolved gas drive is formed. At the same time, some dissolved gas would form bubbles in the crude oil, which increases the elastic energy of the crude oil. At the same time, the faster the pressure drop, the higher the degree of oil recovery (Table 9). The faster the pressure drop, the lower the viscosity of the crude oil, and the more pronounced the phenomenon of foam oil.

Table 9 Recovery factor under different depletion mining rates

Depleted mining rates (MPa/h)	Recovery ratio (%)
5	16.38
7.5	17.32
15	20.8

Experiment on oil displacement efficiency of water flooding

Experimental methods

Experimental instrument: High temperature and high-pressure displacement equipment, as shown in Fig. 28.

Experimental materials: Degassed crude oil, methane, and ethane; Quartz sand.

Experimental objective: The experiment aims to analyze the water drive recovery characteristics of heavy oil under different conditions and identify the influencing factors of water drive.

The experimental steps were as follows

1. According to the bubble point pressure, temperature (65 °C) and dissolved gas–oil ratio, the live oil was compounded;
2. The volume of saturated water is the volume of water injection, the porosity is the ratio of the volume of water injection and the volume of sand filling pipe, and the temperature of the incubator is the reservoir temperature;
3. Connect the experimental device and inject water, test the pressure difference at both ends of the sand filling pipe, calculate the permeability of the sand filling pipe, and control the permeability of the sand filling pipe at about 1500 mD, as shown in Fig. 28;
4. The core is saturated with live oil, the backpressure is set at 15 MPa, the initial oil saturation is calculated according to the produced water, and the core is aged for 24 h under the formation temperature;
5. According to the set pressure drop rate of 5 MPa/h, gradually reduce the backpressure to the displacement pressure, and record the relationship between oil production and gas production and pressure in the process of depletion development;
6. After the pressure is reduced, the subsequent water flooding is carried out at 0.5 mL/min, 1 mL/min, and 1.5 mL/min, and the changes of pressure, oil production, and water production are recorded. Water flooding experiment was carried out by setting different displacement pressure;
7. Change the parameters, repeat (1)–(5), and carry out water flooding experiments with other factors.

Experimental result

The pressure drops to atmospheric pressure

The permeability of the sand filling pipe is 1315 mD, the dripping water is 45 mL, the porosity is 45.9%, the saturated

Fig. 32 The dynamic curve of pressure drop to atmospheric pressure

Fig. 33 Dynamic curve of pressure drop to 3 MPa

oil is 40 mL, the oil saturation is 0.89, and the incubator temperature is 65 °C. The experimental results are shown in Fig. 32.

It can be seen from Fig. 32 that during water injection displacement, due to the unfavorable oil–water mobility ratio, the water breakthrough is earlier, and 0.11 PV water breakthrough is injected. After water breakthrough, the water cut rises rapidly and rapidly rises to more than 80%. Most of the crude oil is produced at high water cut; 0.5 mL/min to 1 mL/min and 0.61% to 1.5 mL/min. Therefore, the total recovery of the water drive is increased by 15.61%. At the same time, when the injection rate is higher, the viscosity of crude oil would decrease so that the recovery degree would increase. Thus, the total recovery of depletion and water flooding is 32.75%.

The pressure drops to 3 MPa

The permeability of sand filling pipe is 1425 mD, the porosity is 39.75%, the dripping water is 39 mL, the saturated oil is 38 mL, and the incubator temperature is 65 °C. The experimental results are shown in Fig. 33.

It can be seen from Fig. 33 that during water injection displacement, 0.26 PV water breakthrough is injected, and after water breakthrough, the water cut rises rapidly to more than 80%. Most of the crude oil is produced at high water cut. When the injection rate is 0.5 mL/min, the recovery degree is increased by 21.06%. When the injection rate is increased to 1 mL/min, the recovery degree increases by 5.26%. When the injection rate increases to 1.5 mL/min, the recovery degree increases by 2.63%. The total recovery degree of water drive is increased by 28.95%. At the same time, when the injection rate is higher, the viscosity of crude oil would decrease so that the recovery degree would increase. The total recovery rate of depletion and water flooding is 34.21%.

The pressure drops to 8 MPa

The permeability of sand filling pipe is 1326 mD, the porosity is 38.73%, the dripping water is 38 mL, the saturated oil is 35 mL, and the incubator temperature is 65 °C. The experimental results are shown in Fig. 34.

It can be seen from Fig. 34 that when the pressure is reduced to 8 MPa, 0.26 PV water breakthrough is injected. After the water breakthrough, the water cut rises rapidly and rises to more than 80%. After the water breakthrough, oil continues to be produced at high water cut, and most crude oil is produced at high water cut. 0.5 mL/min, the recovery rate is 27.14%, continue 1 mL/min water flooding, improve the recovery rate by 2.86%, 1.5 mL/min improve the recovery rate by 1.43%. Appropriately

a. Water content curve of pressure drop to 8MPa

b. Gas oil ratio curve of pressure drop to 8MPa

c. Recovery degree curve of pressure drop to 8MPa

Fig. 34 The dynamic curve of pressure drop to 8 MPa

Fig. 35 The dynamic curve at 100 °C

increasing the water injection rate can increase the swept volume and the recovery degree. The total recovery rate of water flooding is increased by 31.43%. At the same time, when the injection rate is higher, the viscosity of crude oil would decrease so that the recovery degree would increase. The total recovery rate of depletion and water flooding is 32.86%.

°C water flooding

By changing the incubator's temperature, the influence of the experimental temperature on the recovery factor is studied. The permeability of the sand filling pipe is 1215 mD, the porosity is 37.71%, the dripping water is 37 mL, the saturated oil is 34 mL, the incubator's temperature is 100 °C, and the pressure is reduced to 8 MPa. The experimental results are shown in Fig. 35.

It can be seen from Fig. 35 that when the temperature rises to 100 °C and the pressure drop to 8 MPa, the water breakthrough is 0.27 PV. After the water breakthrough, the water cut rises rapidly to more than 80%. Most of the crude oil is produced at high water cuts. The recovery rate is 33.82% when the water injection rate is 0.5 mL/min, 2.95% when the water injection rate is 1 mL/min, and 1.47% when the water injection rate is 1.5 mL/min. Properly increasing water injection rate and formation temperature can increase swept volume and recovery degree. The total recovery degree of depletion and water flooding is 39.71%, 6.85% higher than 65 °C. As the temperature increases, the viscosity of crude oil decreases, the oil–water mobility ratio decreases, and the water flooding effect is improved.

Summary

It can be seen from the above experiments that the water drive effect is related to the water drive speed. The higher the water drive speed is, the higher the oil drive efficiency is. At the same time, it is related to the timing of water injection. When water is injected near the bubble point pressure, the total recovery degree is the highest. Increasing the temperature can reduce the viscosity of crude oil, improve the oil–water mobility ratio, and increase the oil displacement efficiency by 6.85% (Table 10).

Experiment on sweep efficiency of water flooding

Experimental methods

Experimental materials: Degassed crude oil and kerosene.

Table 10 Water drive oil displacement efficiency

Development mode	Recovery ratio (%)			
	Incubator's temperature is 65 °C			Incubator's temperature is 100 °C
	The pressure drops to atmospheric pressure	The pressure drops to 3 MPa	The pressure drops to 8 MPa	The pressure drops to 8 MPa
Depletion development	17.14	5.26	1.43	1.47
Injection speed 0.5 mL/min	29.64	26.32	28.57	35.29
Injection speed 1 mL/min	32.14	31.58	31.43	38.24
Injection speed 1.5 mL/min	32.75	34.21	32.86	39.71

a. Visual model diagram **Fig. 37** Sweep efficiency curve at 500 cp **b. 2D visual simulation experiment device****Fig. 36** Visualization model

Experimental purpose: Through a 2D visual model simulation experiment, the water drive development law, oil and water production characteristics of horizontal wells with different crude oil viscosity and injection speed are studied,

and the influencing factors of water drive sweep efficiency are analyzed.

Experiment steps

1. Make a 2D visual simulation model, and the schematic diagram of the model is shown in Fig. 36. The model's size is 20 cm in length, 20 cm in width, and 0.5 cm in thickness. The visualization model is filled with transparent glass beads;
2. The crude oil was mixed with kerosene, and the simulated oil with the required viscosity was prepared. The simulated oil with a specific viscosity was injected into the model, and the volume of crude oil injected into the model was recorded;
3. The model is placed for 24 h. After the model is solidified, a specific injection rate is set for water flooding, and the sweep efficiency is measured at different times.

Fig. 38 Different time spread under 500 cp

a. Injected 0.1PV

b. Injected 0.2PV

c. Water moment

d. Injected 0.8PV

e. Injected 1.5PV

f. Injected 2.5PV

Fig. 39 Sweep efficiency curve at 700 cp

Experimental result

The simulated oil with a viscosity of 500 and 700 cp was prepared for the water flooding experiment, and the water flooding rate was set at 1 mL/min. At the same time, to analyze the influence of injection speed on sweep efficiency, two groups of experiments with an injection speed of 0.5 mL/min and 1 mL/min were carried out for crude oil with a viscosity of 500 cp.

The experimental results of viscosity 500 cp and injection rate 1 mL/min are shown in Fig. 37 and Fig. 38.

It can be seen from the figure that at the beginning of water injection, the advance of the water drive front is relatively uniform. With the progress of the water drive, the injected water has a sudden advance due to fingering. When 0.25 pv is injected, the water breakthrough occurs in the production well, and the sweep efficiency is 0.33 when water breakthrough occurs. As the water injection continues, the swept volume expands, and the final sweep efficiency is 0.66.

The experimental results of viscosity 700 cp and injection rate 1 mL/min are shown in Figs. 39 and 40.

It can be seen from the figure that the advance of the water drive front is more uniform at the beginning of water injection. With the progress of the water drive, due to the increase in crude oil viscosity, the oil–water mobility ratio becomes more extensive, the fingering is more serious, and

the water breakthrough time becomes short. When 0.20 pv is injected into the production well, the sweep coefficient is 0.26 at the water breakthrough time. As the water injection continues, the swept volume expands, and the final sweep coefficient is 0.62.

The experimental results of viscosity of 500 cp and injection rate of 0.5 mL/min are shown in Figs. 41 and 42. It can be seen that the advance of the water drive front edge is more uniform at the beginning of water injection. With the progress of the water drive, the injected water would suddenly advance due to fingering. When 0.22 pv is injected, the water breakthrough occurs in the production well, and the sweep efficiency is 0.24 at the time of water breakthrough. As the water injection continues, the swept volume expands, and the final sweep efficiency is 0.61.

Summary

Through the above experiments, it can be seen that the injected water would break through quickly during water injection development, and after water breakthrough, the sweep efficiency will further increase, and the sweep efficiency would decrease with the increase in crude oil viscosity but increase with the increase in injection speed (Table 11).

Conclusions

In this manuscript, through the experiment of percolation mechanism and displacement characteristics of heavy oil cold recovery, the following conclusions are obtained.

1. The crude oil PVT experiment shows that the bubble point pressure is related to the pressure drop speed. The faster the pressure drop, the lower the bubble point pressure, showing the characteristics of the foaming oil, and the foam oil phenomenon is observed in the PVT tube. The bubble point pressure of crude oil under formation conditions is 3.54 MPa.
2. The falling ball viscometer experiment shows that the higher the GOR of crude oil, the lower the crude oil viscosity. When the GOR is greater than 9, the viscosity decreases slowly. The viscosity of crude oil is sensitive to temperature and decreases rapidly with the increase in temperature. When it is higher than 85 °C, the decrease range decreases. The temperature

Fig. 40 Different time spread under 700 cp

rises from 65 to 105 °C, and the viscosity of crude oil under formation conditions decreases from 7732.22 to 1188.46 cp.

3. The viscosity-temperature test shows that the viscosity of crude oil decreases with the increase in shear rate at the same temperature, showing the characteristics of shear thinning. With the increase in temperature, the crude oil viscosity first decreases rapidly. When the

temperature is higher than 80 °C, the decrease range of crude oil viscosity decreases.

4. The capillary viscosity experiment shows that when the GOR of crude oil is 4, and the flow rate is 0.2 mL/min, the crude oil viscosity is 3540–991 cp. The viscosity of crude oil is between 2815 and 226 cp at the flow rate of 0.5 mL/min. With the increase in temperature, the

Fig. 41 The curve of sweep coefficient change under viscosity of 500 cp and injection speed of 0.5 mL/min

viscosity decreases, the shear rate increases and the viscosity decreases.

5. The percolation experiment of crude oil core shows that when the temperature is 65 °C and 95 °C, and the pressure gradient is small, the percolation velocity increases slowly with the increase in pressure gradient, and the relationship between percolation velocity and pressure gradient is a curve of concave velocity axis. With the increase in pressure gradient, the seepage velocity increases. When the pressure gradient reaches a certain value, the seepage velocity and pressure gradient gradually become linear. When the temperature is 110 °C, the seepage velocity is approximately linear with the pressure gradient.
6. The percolation experiment of crude oil core shows that the crude oil viscosity first decreases rapidly with the increase in percolation velocity and then tends to be flat, forming a power function relationship. The crude oil viscosity ranges from 600 to 730 cp at the formation temperature of 65 °C.
7. The depletion test of crude oil shows that when the pressure is higher than the bubble point, the oil pro-

duction is small, and the cumulative oil production increases slowly. When the pressure is lower than the bubble point, the oil production increases and the cumulative oil production increases rapidly. When the pressure continues to decrease, the oil production gradually decreases. When the pressure is higher than the bubble point, the gas-oil ratio remains relatively stable. When the pressure is lower than the bubble point, the gas-oil ratio fluctuates slightly, the pressure continues to decrease, and the gas-oil ratio increases rapidly.

8. The recovery degree is related to the depletion rate. The faster the depletion rate is, the higher the recovery degree is. For example, the depletion rate increased from 5 to 15 MPa/h, and the recovery rate increased from 16.38 to 20.80%.
9. The water flooding experiment of crude oil shows that with the increase in water injection rate, the oil seepage rate increases and the viscosity decreases, increasing the oil displacement efficiency and improving the water flooding effect.
10. After the water breakthrough, the water content of crude oil could rapidly increase to more than 80%, and the crude oil can continue to be produced in the high water cut stage.
11. When the oil displacement pressure is near the bubble point pressure, the water flooding effect is the best, and the total recovery is 34.21%. The water flooding effect can be improved by increasing temperature. The recovery degree of water flooding at 100 °C is 6.85% higher than that at 65 °C.
12. The experimental results of sweep efficiency of crude oil water flooding show that the injected water could break through quickly during water flooding, and the sweep efficiency will further increase after water breakthrough. The sweep efficiency decreases with the increase in crude oil viscosity but increases with increased injection speed.

This study provides technical support for the effective production of offshore heavy oil fields.

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Fig. 42 Impact at different times under viscosity of 500 cp and injection speed of 0.5 mL/min

Table 11 Experimental results of water drive sweep efficiency

Viscosity (cp)	Injection speed (mL/min)	Sweep efficiency	
		When water is seen	Final
500	1	0.33	0.66
	0.5	0.24	0.61
700	1	0.26	0.62

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