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OFFSHORE HEAVY OIL DISPLACEMENT USING WATER FLOODING: FLOW CHARACTERISTICS AND EFFICIENCY

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Abstract. In water flooding, residual oil is displaced by injecting water into the reservoir formation. Oil displaced from injection wells is physically swept to adjacent production wells by water. Compared to conventional oil fields, offshore heavy oil fields have low oil recovery using water flooding. If we had a better knowledge of the flow characteristics of the water and oil phases, it would be very useful to improve the oil recovery of the heavy oil reservoir.

In developing oil fields, it is important to study the patterns of changes in the flow characteristics of the oil and water phases. This will guide the development of numerical simulation models.

This study considered the geological characteristics, fluid properties, and construction technology of an offshore oil field with heavy oil. The relative permeabilities of water and oil were investigated using steady-state and unsteady-state methods. With the unsteady state method, the effect of core permeability, water washout, and oil viscosity on the relative permeability curve and oil displacement efficiency of water flooding has been investigated. Artificial cores were utilized in the experiments. The artificial cores were developed to simulate the structure of unconsolidated sandstone in an offshore oil field. Computed tomography and mercury pressure testing are used to demonstrate the change in the internal structure of the core.

Water washout forms the “cleaning” and “erosion” function, which affects core pore structure, increases the radius of the core pore throat, and increases the core permeability. It has the same effect on relative permeability curves and oil displacement efficiency as it does on increased permeability. The total oil recovery decreases with increasing oil viscosity since the ability to control water mobility weakens during the flooding process. Moreover, the coverage volume of the displacing water phase decreases, and the two-phase flow range narrows.

Water sweeps expand as core permeability increases, resulting in a wider two-phase flow as the relative permeability of the water phase increases. In turn, this enhances oil efficiency displacement and total oil recovery.

Keywords: Heavy oil; Relative permeability; Oil displacement; Waterflooding; Offshore

1. Introduction

Waterflooding is a highly effective process that involves injecting water into an oil reservoir. This helps to maintain the reservoir pressure and produce additional oil after reaching the production limit. This is achieved by injecting water into certain wells within an oil field. Oil is then pushed towards the remaining production wells through the formation.

Heavy oil is a type of crude oil that is very viscous, meaning that it is thick and does not flow easily. Low hydrogen-to-carbon ratio in the oil molecule and other minerals like asphaltenes, resins, sulfur, vanadium, and nickel can increase the oil density (Meyer, Attanasi & Freeman 2007).

The Bohai offshore oil field, which is located in the Bohai Bay area, in northern China, has been studied in this work .There are abundant heavy oil reserves in the studied offshore oil field, but sedimentary conditions affect its development process, causing problems like high oil viscosity, unconsolidated rock structure, and large reservoir heterogeneity (Alvarado & Manrique 2013; Al-Obaidi & Khalaf 2019). It can result in long-term low-water flooding, with a low oil recovery rate of 18 – 24% (LIU J et al. 2023; Mai & Kantzas 2007; Yang et al. 2022; Hofmann, Al-Obaidi & Chang 2023).

During the development of an oil field with heavy oil during waterflooding, it is crucial to investigate the mechanism of formation fluid flow to determine the most rational development plan and to improve oil recovery. When developing fields during waterflooding, the relative permeability curves of oil and water phases should be used to refine the characteristics of water and oil flow in the reservoir for enhanced oil recovery (Jianchun et al. 2016; Renyi et al. 2022; Smirnov & Al-Obaidi 2008; QI G. et al. 2022; Møyner, Krogstad & Lie 2015).

The unconsolidated structure of the reservoir rock makes coring offshore fields difficult, and when the cores are transported from the formation to the surface, they become loose sand (Cao et al. 2021; Mengqing et al. 2022; Chen et al. 2017). Studies of oil and water relative permeability using natural cores are mainly focused on conventional sandstone, low-permeability, and tight reservoirs. However, very few studies have been conducted on oil and water relative permeability or oil displacement efficiency during water flooding in offshore heavy oil fields (Lu et al. 2019; Al-Obaidi 2016; Ren, Li, Fu et al. 2018; Nianhao et al. 2022). Further, unlike onshore oil fields, offshore oil fields are limited by platform life and operating costs. The industry generally adopts the "strong injection and strong production" approach (Yuxi et al. 2019; Jiang et al. 2023; Hofmann, Al-Obaidi & Hussein 2022; Silva & Guedes 2021). The daily injection volume of one well can reach thousands of cubic meters. Thus, washing out of the injected water onto the uncemented rock structure will lead to a significant increase in the reservoir permeability, which strongly affects the flow characteristics of the two-phase fluid (Yu et al. 2018; Davide &

Ilenia 2020; Al-Obaidi 2022; Catherine et al. 2021). In this work, the geological characteristics of the reservoir, fluid properties and construction technology of the studied offshore oil field with heavy oil were taken into account. Based on the development of artificial cores with a loose sandstone structure in offshore oil fields, a method for testing the relative permeability curves is optimized. Both the steady-state and unsteady-state methods were used to investigate the effect of water flooding on water and oil relative permeabilities. However, the unsteady state method was used to investigate the influence of core permeability, water washout, and oil viscosity on the relative permeability curves and the efficiency of oil displacement using water flooding. This study provides a theoretical basis for enhanced oil recovery of heavy oil reservoirs.

2. Methodology and materials

The oil used in the experiments is degassed oil from the studied oil field (Bohai offshore oil field - China) mixed with kerosene. Bohai is rich heavy oil in resources. It has large reserves, deep wells, and a wide characteristic viscosity range. Oil-containing layers are mostly located in the Bohai Bay area, including the Qianshan, Guantao, and Minghuazhen groups (Lu, Hong 2018; Kang, Xiaodong et al. 2011). The viscosities of the oil at a reservoir temperature of 65°C were 70, 310, 530, 840, 1210, and 1580 mPa s. The oil samples taken here have been from different formations throughout this oil field. The injected formation water from the studied oil field was used as process water for the experiments. Mineralization was 9947.8 mg/l, and mass concentrations of ions are shown in Table 1.

Table 1. Ion composition of the water used in the experiments

Ionic composition	Ca^{2+}	Mg^{2+}	Na^{+}	CO_3^{2-}	HCO_3^{-}	Cl^{-}	SO_4^{2-}	Degree of mineralization
Ion mass concentration (mg/L)	275,6	305,5	3090,2	0,0	311,5	5879,7	85,3	9947,8

This table shows that the formation water used in the experiments is briny due to the high concentrations of Na^+ and Cl^-.

In the experiment, artificial cores were used, which were made from quartz sands and natural oil sands cemented with epoxy resin. Artificial cores have been developed to model the structure of unconsolidated sandstone in an offshore oil field (Table 2).

Table 2. The details of the studied artificial cores

Core number	Initial permeability, $x10^{-3}\ \mu m^2$	Gas Permeability, $x10^{-3}\ \mu m^2$	Geometric core size: cm × cm
1000-1	1012	1000	2.5 x 8
1000-2	1008	1000	2.5 x 8
2500-1	2486	2500	2.5 x 8
2500-3	2510	2500	2.5 x 8
2500-4	2512	2500	2.5 x 8
2500-5	2515	2500	2.5 x 8
2500-6	2480	2500	2.5 x 8
2500-7	2508	2500	2.5 x 8
2500-8	2485	2500	2.5 x 8
2500-9	2480	2500	2.5 x 8
5000-6	4985	5000	2.5 x 8

An unsteady state method was used to determine the relative permeability and efficiency of oil displacement in rocks by a two-phase fluid. Considering the large workload (complex operation and long-time) of the steady method and error propensity in the experimental process, the existing relative permeability study mainly uses the unsteady method, which has many reference materials (Amir, Xiongyu & David 2016). In addition, the unsteady state method can meet the demand for displacement efficiency testing (Janos et al. 2002; Qing et al. 2021; Al-Obaidi & Khalaf 2023; Juan & Chuanrong 2021). In this regard, in subsequent experiments, the unsteady state method is used to test the phase permeability.

The experimental steps of the steady state method are as follows:

1. At room temperature, the core is evacuated and saturated with water.
2. From saturated simulated oil, irreducible water is displaced by oil at 65°C. Then determine the phase permeability of oil when saturated with irreducible water and record the saturation pressure.
3. At 65°C and stable total fluid injection rate, oil and water were injected into the core at a ratio of 20:1, 10:1, 5:1, 1:1, 1:5, and 1:10. After the flow became stable, the pressure drop and oil and water consumption at the outlet were recorded until the end of the experiment.
4. The saturation of irreducible water of different periods was calculated by the material balance method (Pei J et al. 2022; Tang Ligen et al. 2014; Al-Obaidi & Guliaeva 2002; Long Yang et al. 2022).

5. The relative permeability of the two phases was calculated by the JBN method (Chen, Kianinejad & Dicarlo 2016; Zhang, He, Jiao et al. 2014), and a phase permeability curve was plotted.

The experimental steps of the unsteady state method are as follows:

1. At room temperature, the core is evacuated and saturated with water.
2. At 65°C, irreducible water obtained from saturated simulated oil is displaced by oil. Then determine the phase permeability to oil when saturated with irreducible water and record the saturation pressure (Table 3).
3. In order to eliminate the end effect at 65°C, the oil is displaced by water at a constant rate of 0.8ml/min. The time of water appearance, the volume of cumulative oil production and cumulative liquid production, and the pressure difference between the two ends of the core during the appearance of water are recorded. Depending on the volume of oil production, an appropriate time interval is selected and the recording interval is gradually expanded. Under the condition of a water cut of 100%, the water permeability (Krw) is determined at residual oil saturation, Sor (Table 4).
4. The saturation of irreducible water (Swi) of different periods was calculated by the material balance method (Table 5), the relative permeability of the two phases was calculated by the JBN method, and a phase permeability curve was plotted.
5. The oil displacement efficiency was calculated, and a curve was plotted between the oil recover factor (RF) and the water injection pore volume multiple.

Table 3. Saturation experiment study results under steady and unsteady state conditions

Method	Parameters				
	Core number	Oil viscosity (mPa·s)	Permeability (10^{-3} μm^2)	Irreducible water saturation (%)	Residual oil saturation (%)
Steady state method	2500-1	70	2486	24,7	49,0
Unsteady state method	2500-4	70	2512	24,6	39,8

Table 4. Saturation experiment and oil displacement efficiency study results

Number of core	Oil viscosity (mPa·s)	Permeability (10^{-3} μm^2)	Irreducible water saturation (%)	Residual oil saturation (%)	Oil displacement efficiency (%)
1000-1	70	1012	28,7	44,1	38,2
2500-4	70	2512	24,6	39,8	46,7
5000-6	70	4985	21,4	35,0	55,5

Table 5. Oil displacement efficiency study and saturation experiment results

Core number	1000-1	1000-2
Oil viscosity (mPa·s)	70	70
Volume of water washout (PV)	-	1000
Permeability (10^{-3} μm^2)	1012	1008
Irreducible water saturation (%)	28,7	26,2
Residual oil saturation (%)	44,1	35,1
Oil displacement efficiency (%)	38,2	43,7

The viscosity of the test samples was determined using a Brookfield DV-II viscometer (Daubert & Farkas 2010; Al-Obaidi, Guliaeva & Smirnov 2020), the rotation speed was 6 rpm, and the test temperature was 65 °C (Table 6). The experimental setup of the displacement experiment consisted of a pump, a pressure transducer, a core holder, a hand pump, an intermediate container, and other parts. All parts except the pump were placed in a 65°C thermostat. A Hitachi S-3400N scanning electron microscope (SEM) (Wang et al. 2012; Marsel et al. 2022) and a SkyScan1172 high-resolution computed tomography scan (Zhang, Lee & Zhang J. 2019; Li C. et al. 2022) were used to analyze core pore structure changes before and after flooding. An automatic mercury injection tool 9520 was used for measuring the core average pore radius (Al-Obaidi, Patkin & Guliaeva 2003; Liang et al. 2017).

Table 6. Oil displacement efficiency study and saturation experiment results

Number of core	Oil viscosity (mPa·s)	Permeability (10^{-3} μm^2)	Irreducible water saturation (%)	Residual oil saturation (%)	Oil displacement efficiency (%)
2500-3	18	2510	28,2	65,5	51,8
2500-4	70	2512	24,6	39,8	46,7
2500-5	310	2515	22,5	42,0	45,8
2500-6	530	2480	21,1	44,2	44,0
2500-7	840	2508	19,5	48,7	39,5
2500-8	1210	2485	18,6	50,5	37,9
2500-9	1580	2480	17,7	60,7	34,4

3. Results and discussions

3.1. Relative permeability test method

Relative water-flooding permeabilities under different test methods are shown in Table 2 and Figure 1.

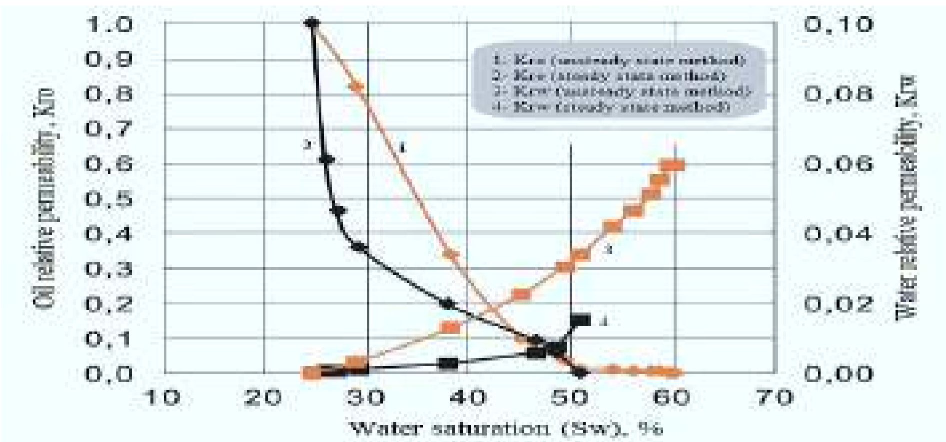


Figure 1. Curves of relative permeability under conditions of various test methods (Core samples 2500-1 and 2500-4)

Both Table 3 and Figure 1 show that the trend of changing the relative permeability of water-flooding with steady and unsteady methods is basically the same. Still, the difference in the phase permeability of water is due to different experimental methods and data processing methods (Li & Horne 2006).

3.2. Influence of core permeability on relative fluid permeability and oil displacement efficiency

Based on waterflooding and saturation experiments conducted at different core permeabilities, Table 4 illustrates the results of oil displacement efficiency.

Relative permeability curves, dependence of oil recovery factor (RF) and PV number (core pore volume) are shown in Figures 2 and 3.

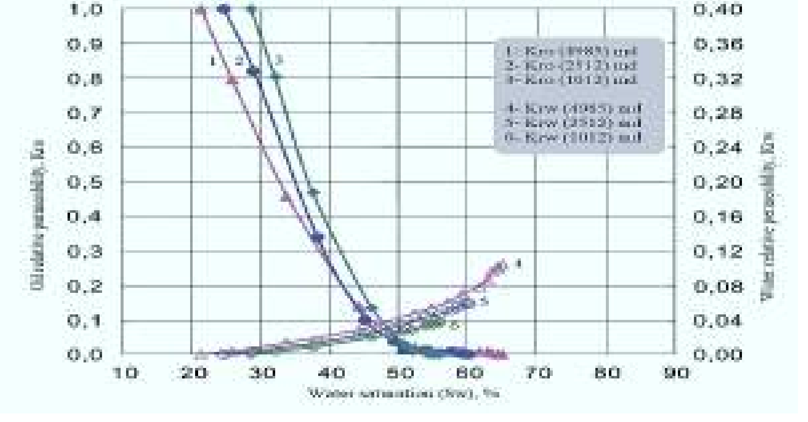


Figure 2. Curves of relative permeability under different core permeabilities (Core samples 1000-1, 2500-4 and 5000-6)

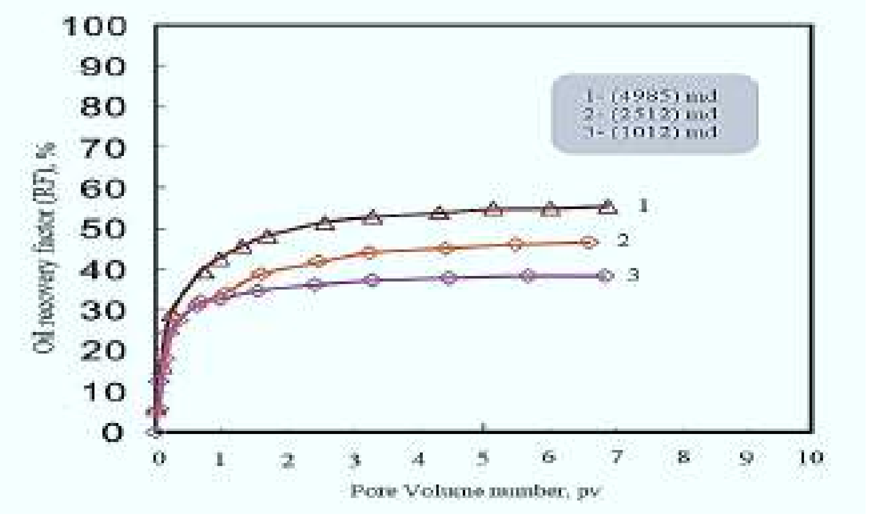


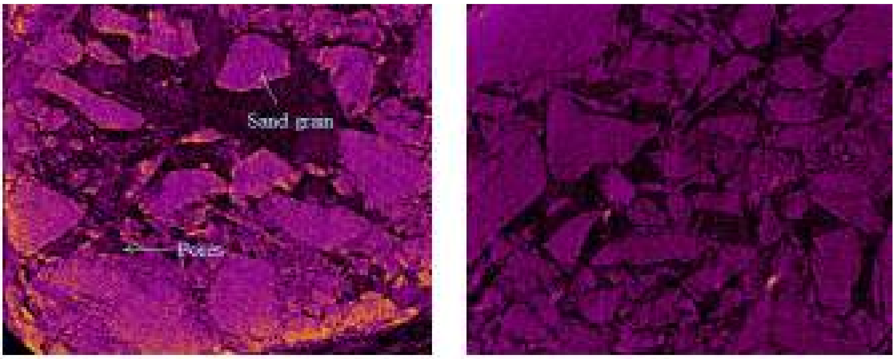
Figure 3. PV number and oil recovery factor curves (Core samples 1000-1, 2500-4 and 5000-6)

From Table 4, Figures 2, and 3, it can be seen that the core permeability affects the relative permeability of oil and water and the efficiency of oil displacement during water flooding. During the displacement of water with oil to create irreducible water, the oil phase occupies the pore space and displaces the water phase (Liu Q., Wu K., Li X. & et al., 2021). The oil phase erodes the “water film” on the surface of the rock pore throat, trying to occupy the rock surface. This causes part of the “water film” to separate. At the same time, polar substances in the oil phase, such as naphthenic acid, resins and asphaltenes, are adsorbed on the surface of the rock pore throat to form an “oil film”. In addition to increasing core permeability, the average radius of the pore throat increases as well, allowing the oil phase to enter more core pores and displace the water phase. This leads to an increase in initial oil saturation, a decrease in irreducible water saturation, and an increase in the area of the oil film on the rock surface due to an increase in the initial oil saturation. In increased oil films on the surfaces of pore throats, the hydrophilicity of the core decreases and the water-oil distribution changes. Part of the irreducible water, initially attached to the surface of the rock pore throat in the form of a “water film”, is dispersed in the oil phase in the form of water droplets. During the water flooding process, these droplets cause the Jamin effect, which prevents the oil phase from flowing, reducing its relative permeability (Jiang 2018; Jia P. et al. 2023; Al-Obaidi 2009; Wan-Li et al. 2022). Additionally, increasing the radius of the pore throat decreases the flow resistance of the aqueous solution in the core, increases fluidity and coverage area, and increases relative permeability and oil recovery.

Thus, in the process of water flooding with increasing core permeability, the relative permeability of the oil phase decreases, and the relative permeability of the water phase increases. Moreover, a decrease in irreducible water saturation (Swi) and residual oil saturation (Sor) occurs, as well as a shift toward the left of the isotonic point (neutral wet condition) and an increase in the oil recovery factor.

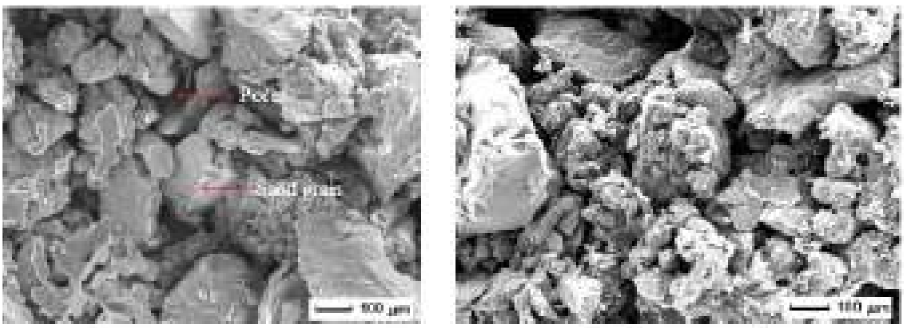
3.3. Effect of water washout on fluids relative permeability and oil displacement efficiency

The artificial cores were flushed out with injected water (injection rate 1.0 ml/min, injection volume 400 PV). Images of computed tomography (CT) and scanning electron microscope (SEM) are shown in Figures 4 and 5.



(a) Before water washout (b) After water washout

Figure 4. Computed tomography (CT) images of the core sample (1000-1)



(a) Before water washout (b) After water washout

Figure 5. Scanning electron microscope (SEM) images of the core (1000-1)

Note that the Computed tomography (CT) system generates cross-sectional images (slices) of the core using computer processing. Different body parts show up as different colours on a (CT) scan, because different parts of the body absorb different amounts of x-rays. Scanning electron microscope (SEM) images were taken to closely examine the microscale pore-throat configuration.

Figures 4 and 5 show that water leaching has an effect on the pore structure of the rock. The pore size of the core, where there was no washout (a) , is small and contains many minerals. After washing out with water (b) , the mineral residue in the core pores is washed out and removed with liquid migration, and the inner pore throat of the core becomes smooth and clean. Also, injected water has a denudation effect on the pore throat of the core. The complex effect of the above actions is that the average radius of the core pore throat increases (Figure 6).

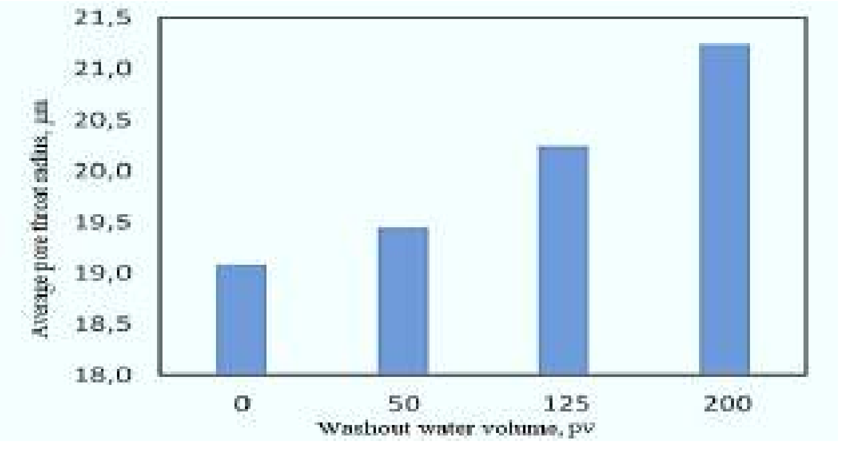


Figure 6. Average radius of the core pore throat

The average radius of the core pore throat increases with an increase in the volume of injected water (YIQIAN QU, et al. 2021). Due to the strong injection and strong production mode in offshore fields, the permeability of reservoir rocks can be significantly increased. It is therefore important to understand the physical properties of this reservoir during the process of development.

The waterflooding relative permeability test is carried out for a water washout core and a non-water washout core, respectively. The results of the study of the efficiency of oil displacement and saturation experiments are shown in Table 5. Relative permeability curves, dependence of oil recovery factor and PV number are shown in Figures 7 and 8.

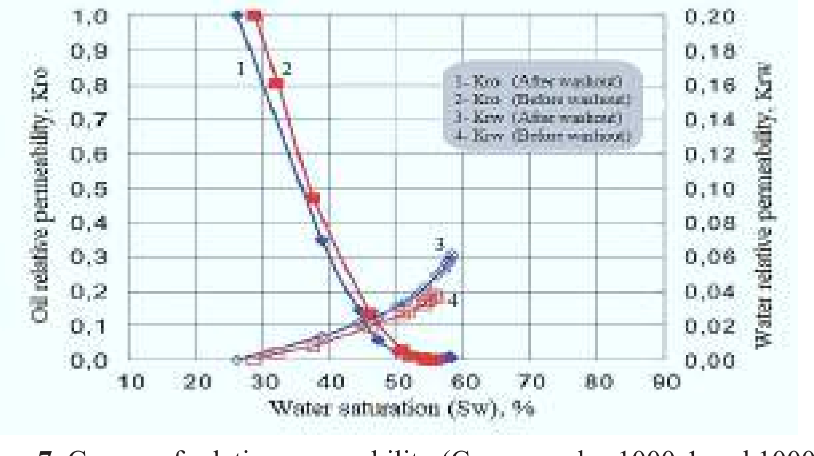


Figure 7. Curves of relative permeability (Core samples 1000-1 and 1000-2)

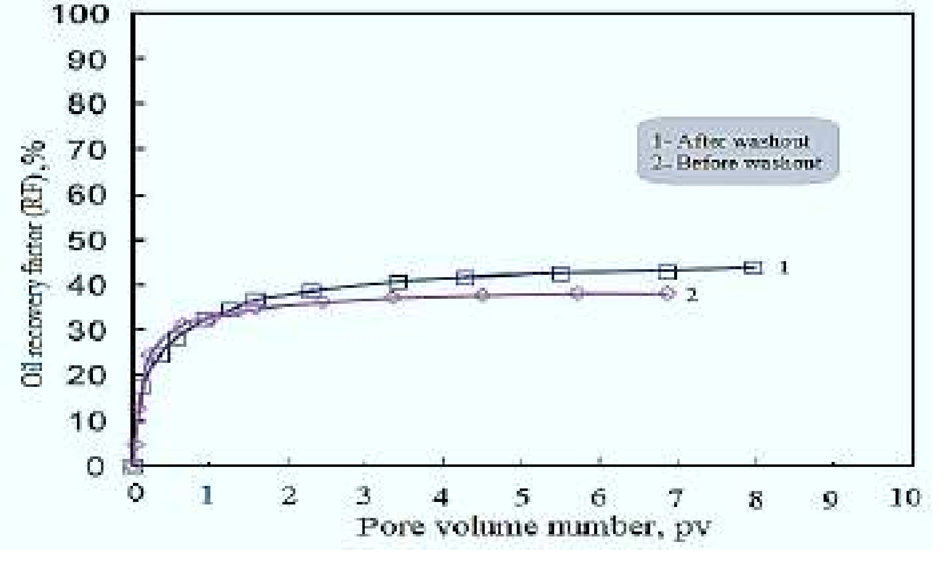


Figure 8. Oil recovery factor and PV number dependence curves
(Core samples 1000-1 and 1000-2)

According to Table 5, Figures 7, and 8, the oil relative permeability decreases after water washout, the water relative permeability increases, and the saturation of irreducible water and residual oil decreases. Moreover, the right endpoint of the curve moves to the right, the oil recovery factor increases and the isotonic point moves to the left and the corresponding value of relative permeability increases. Long-term water washout can change the pore structure of the core, and the effects of "cleaning" and "erosion" increase the radius of the pore throat (Lufeng Zhang et al. 2019). Macroscopically, the core permeability increases, and the changes in phase permeability and oil displacement efficiency are the same as with an increase in permeability.

3.4. The influence of oil viscosity on the relative permeability of fluids and the efficiency of oil displacement

The results of the study of the efficiency of oil displacement by water flooding and saturation experiments under conditions of different oil viscosities are shown in Table 6. Figures 9 and 10 show the relative permeability curves and the relation between the oil recovery factor and PV number respectively.

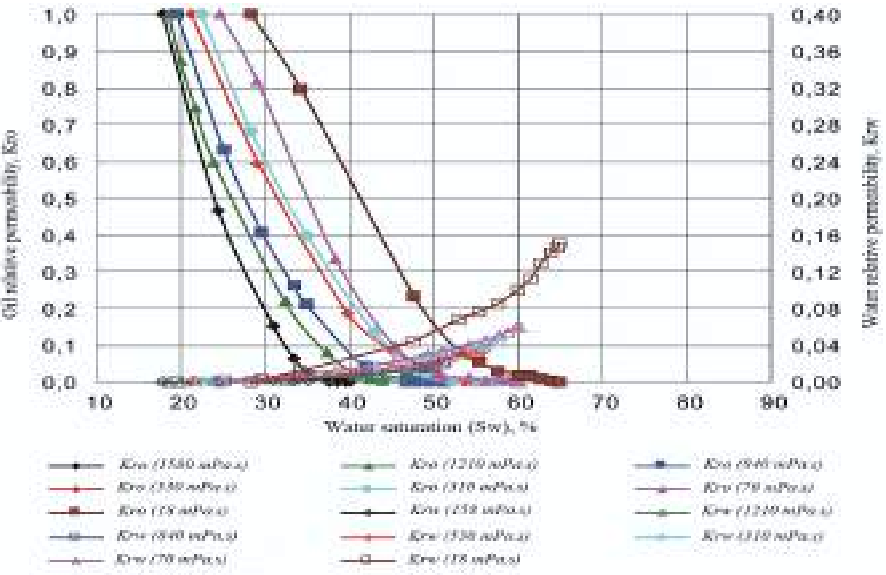


Figure 9. Relative permeability curves for different viscosities of oil (Core samples 2500-4, 2500-5, 2500-6, 2500-7, 2500-8 and 2500-9)

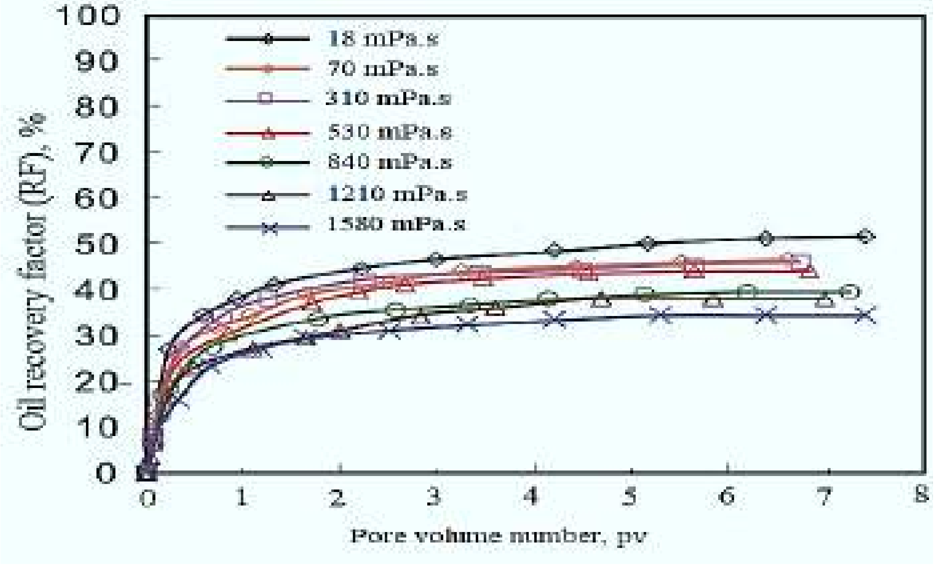


Figure 10. Oil recovery factor and PV number dependence curves (Core samples 2500-4, 2500-5, 2500-6, 2500-7, 2500-8 and 2500-9)

From Table 6, Figures 9, and 10, it can be seen that the viscosity of oil affects the relative permeability of oil and water and the efficiency of oil displacement during waterflooding. When oil's viscosity increases, so does the viscosity ratio between oil and water in the process of creating irreducible water through injection. As a result, the ability to control the flow of the oil phase increases, so that the original water phase can be forced out of pores by creating a larger pore space. Thus, the volume of the oil phase and the initial saturation of the pores with oil increase, while the saturation of irreducible water decreases. A rise in oil viscosity can also increase the impact of oil erosion on the water film on the rock surface, as well as the number of polar substances attached to the rock surface. As the oil phase contains more naphthenic acid, gums, and asphaltenes, this occurs (Mostafa, Shahab & Masoud 2014). Both effects result in an increase in the oil film on the surface of the rock pore throat and a decrease in core hydrophilicity. Oil and water distribution changes as the hydrophilicity of the core weakens (Guangfeng, Hengli, Jiachao Et Al., 2023). Initially attached to the surface of the rock pore throat as "water film", the irreducible water transforms into water droplets, and moves into the oil phase. During flooding, these droplets cause the "Jamin effect", which prevents the oil phase from flowing. In addition, oil flow resistance increases with increasing viscosity, so the relative permeability of the oil phase will decrease during waterflooding. A higher oil viscosity also leads to a higher mobility ratio between displacing and displaced phases, as well as an increase in the occurrence of flood tongues. As a result of a decrease in the volume of the displacement phase coverage, the relative permeability of the oil phase and oil displacement efficiency decrease.

With an increase in oil viscosity, the relative permeability of oil and water decreases, the saturation of irreducible water decreases, the residual oil saturation increases (Wang, Dong & Asghari 2006). Moreover, the right endpoint of the curve and the isotonic point move to the left, the passage zone of the two-phase flow decreases, and the oil recovery factor decreases. Thus, in the development of a heavy oil field, the viscosity of the oil can be reduced by thermal treatment in order to improve the fluidity of the two-phase flow and increase the oil recovery of the reservoirs (Qian et al. 2023; Xiaojun et al. 2024; Chang, Al-Obaidi & Patkin 2021).

4. Conclusions

The permeability of rocks has a significant impact on the filtration characteristics of a water-oil two-phase flow. As the core permeability increases, the relative permeability of the aqueous phase increases, the residual oil saturation decreases, the zone of passage of the two-phase flow increases, and the oil recovery factor increases.

It is during washing out with water that the functions of "cleaning" and "erosion" occur, which affects the structure of the core pores and increases the radius of the core pore throat and its permeability. Their effect on the relative permeability curve and the oil displacement efficiency is the same as the effect on the increase in permeability.

Increases in oil viscosity lead to a decrease in the relative permeability of water and oil phases, affecting the ability to control the displacing phase's fluidity. Moreover, it increases the formation of flood tongues, decreases the volume of coverage of the displacing phase, decreases the zone of passage of a two-phase flow, and decreases the ultimate oil recovery for the reservoirs.

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