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# Effect of Salinity on the Imbibition Recovery Process of Tight Sandstone Reservoirs

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**Abstract:** Fracture network fracturing combined with oil–water infiltration and replacement is an effective approach to develop tight sandstone reservoirs. How to further improve oil recovery based on imbibition is a problem encountered during production. In this study, the core of the CHANG-7 tight sandstone reservoir in the Changqing oilfield of the China National Petroleum Corporation (CNPC) is studied. Combined with the newly designed core self-imbibition experiment, the mechanisms of salinity action are studied, and the influence of salinity on the process of imbibition oil recovery is quantitatively characterized. Research results show that the influence of salinity on the imbibition process of tight sandstone reservoirs takes place mainly through two ways; one is to reduce the oil–water interfacial tension, and the other is to construct an osmotic pressure displacement model. The salinity has significant influences on interfacial tension. The interfacial tension of low-salinity brine is only 1/5 of that of distilled water, but in the presence of high-efficiency surfactants, the influence of the salinity on the interfacial tension can be ignored; the greater the difference in salt concentration, the higher the core permeability and the greater the influence of salinity on the process of imbibition and oil recovery in tight sandstone reservoirs. At the initial stage of imbibition, the effect of salinity is less important than that of capillary force. On the contrary, the effect of salinity is much more important than that of capillary force in the middle of imbibition, and the imbibition curve shows a downward trend. At the later stage of imbibition, the fluid tends toward imbibition equilibrium, and the effects of capillary force and salinity are not obvious.

**Keywords:** salinity; tight sandstone reservoir; imbibition oil recovery; osmotic pressure; interfacial tension



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## 1. Introduction

Oil–water infiltration and replacement can maximize the driving effect of capillary force, which is an important means to develop tight sandstone reservoirs with poor physical properties and well-developed micro–nano pore throats [1–5]. There are many factors that restrict the process of imbibition oil recovery, so the efficiency of imbibition oil displacement is often not up to the expected target. As one of the significant factors, the study of the influence of salinity on the imbibition displacement effect is of vital significance for the efficient development of tight sandstone reservoirs.

At present, many scholars have carried out a lot of research on the influence of salinity on oil–water infiltration and replacement. In terms of changing the wettability of the rock surface, Liu, Katende et al. believed that the main reason why low-salinity water improves oil recovery is that low salinity can affect the wettability of the rock surface and make it more hydrophilic [6,7]. Experiments by Mohammadi proved that low-salinity brine can reduce the wetting contact angle of carbonate rocks from 114° to 42°, which can effectively improve the oil imbibition recovery [8]; using zeta potential, Tetteh measured that when the salinity decreased, the charge on the rock surface decreased, and the wettability of the rock changed from oil wettability to neutral wettability [9]. Song explained that the change in wettability was caused by less Na+ surface complexes in low-salinity water by calculating the electrostatic component of the separation pressure [10]. Experiments by Hidayat found that brine solutions containing high $Mg^{2+}$ and $Ca^{2+}$ significantly improved the recovery efficiency of osmotic water [11]. The explanation for this phenomenon by Ghandi et al. is that the brine solution containing divalent ions such as $Mg^{2+}$ and $Ca^{2+}$ can change the wettability of lipophilic rocks to low lipophilic or neutral wettability, thereby improving the imbibition recovery [12].

In terms of changing the properties of the rock surface, Zaeri et al. believed that reducing the salinity of water can expand the water layer on the mineral surface, and the crude oil will be more easily peeled off the rock surface [13]; Cai et al. found that high salinity can inhibit the thickness of the diffusion electric bilayer, thus reducing the adsorption capacity of clay minerals to water and making the absorbed liquid more easily centrifuged out [14]. Bing et al. conducted spontaneous imbibition experiments on tight sandstone cores in 0.21% to 2.1%TDS brine and found that oil production from imbibition in 0.21% TDS brine increased rapidly, resulting in a 4.5% increase in oil recovery [15]. Ren et al. believed that the saturation of the core with high-salinity imbibition can effectively hinder the water sensitivity of the rock sample, thereby avoiding the decrease of core permeability [16]; Chavan et al. found that the oil imbibition recovery is the highest in the salinity range of injected water with TDS of 2000 ppm~5000 ppm, and the composition of the reservoir brine has a significant influence on the optimal salinity of injected water [17].

In terms of changing the driving force of imbibition, Hamad et al. found that the capillary diffusion constant under the condition of spontaneous imbibition of low-salinity water is larger than that under the condition of spontaneous imbibition of high-salinity water [18]. The main mechanism for low-salinity water to increase recovery efficiency is to increase the capillary force. The results of the spontaneous imbibition experiments of Feldmann and Behera showed that the capillary pressure increases with the decrease of the salinity of the injected water [19,20]; by calculating the separation pressure to evaluate the intermolecular force between oil, water, and rock surface, Lin et al. found that the separation pressure value of low-salinity water is higher, which is easier to enter the core bridge plug to improve the oil recovery [21]; Al-Saedi found that the salinity affects the capillary pressure by changing the wetting contact angle and interfacial tension [22]. As the salt concentration increases, the imbibition decreases gradually; Di and Guo found in core displacement experiments that the change of salinity to interfacial tension is the main factor affecting imbibition recovery [23,24]. The lower the salinity of the displacement fluid, the higher the imbibition recovery; Liu established an evaluation model for tight sandstone reservoirs and concluded that fracturing fluids with low salinity are more beneficial to improve oil–water imbibition replacement [25].

However, these studies did not effectively distinguish the effect of salinity and capillary force on core imbibition, nor did they quantitatively characterize the effect of salinity on the process of imbibition oil recovery. This paper uses the newly designed core self-imbibition experiment to explore the main ways that salinity affects the process of imbibition oil recovery, distinguish the effect of salinity and capillary force, and quantitatively characterize the impact of salinity on oil–water infiltration and replacement. The research results have certain guiding significance for analyzing the effect of salinity on the imbibition processes of tight sandstone reservoirs.

## 2. Mechanism of Mineralization

### *2.1. The Influence of Salinity on Interfacial Tension*

In order to study the influence of salinity on interfacial tension, three sets of data were tested. The corresponding interfacial tension values of a high-efficiency surfactant at different concentrations are shown in Figure 1. It can be seen that adding 0.2% surfactant to distilled water reduces the interfacial tension to 0.015 mN/m.

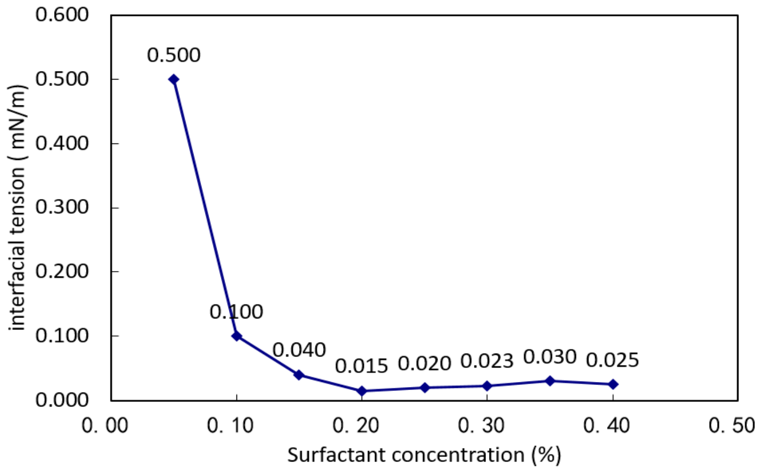



**Figure 1.** Interfacial tension of different concentrations of surfactants.

Figure 2 shows the interfacial tension test data under the influence of two groups of salinity. It can be seen from the blue curve that the interfacial tension of distilled water is 10.70 mN/m when no salt and surfactant are added. As the degree of salinity increases (the target reservoir formation water is of $CaCl_2$ type, where: $Na^+$ is about 4167 mg/L, $K^+$ is about 3889 mg/L, $Ca^{2+}$ is about 1222 mg/L, $Mg^{2+}$ is about 122 mg/L, $Cl^-$ is about 15,194 mg/L, $SO_4{}^{2-}$ is about 267 mg/L, $HCO_3{}^-$ is about 139 mg/L), the interfacial tension decreases rapidly, reaching the minimum value of 1.80 mN/m when the salinity reaches 15,000 mg/L, and then the interfacial tension gradually increases as the salinity increases; adding 0.2% surfactant and salt at the same time, it can be seen from the red curve that the interfacial tension is maintained between 0.01 mN/m–0.10 mN/m. Compared with the curve in Figure 1, the interfacial tension value has little change.

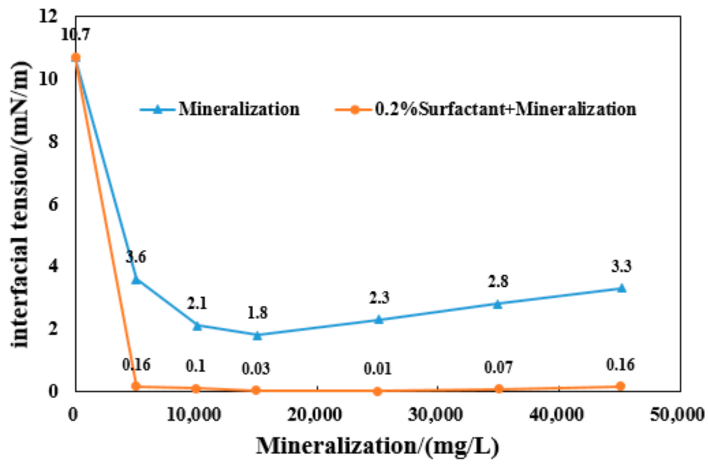



**Figure 2.** The influence of salinity on interfacial tension.

In summary, the degree of salinity has a significant effect on the interfacial tension. Compared with distilled water, the interfacial tension of low-salinity brine is only 1/5 of that of distilled water. This is a negative effect on the process of imbibition and reduces the capillary force, which means that the effect of imbibition is weakened, and this effect is relative. In the presence of high-efficiency surfactants, the effect of salinity on interfacial tension can be ignored.

### 2.2. *The Mechanism of Osmotic Pressure*

As shown in Figure 3, a semi-permeable membrane, allowing water molecules to pass through and preventing other molecules from passing through, was placed at the bottom of the U-shaped tube, low-salinity brine was added to the left of which, and high-salinity brine with equal height was added to the right of which. After a period of inactivity, the height of the fluid on the left of the U-shaped tube decreased, and the height of the fluid on the right increased. There is a height difference between the two, and they maintain a stable state. This shows that there is an additional pressure difference between the salt water with different salinity, which is the osmotic pressure.

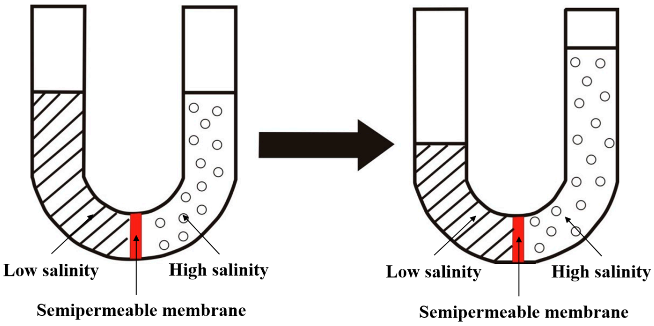



**Figure 3.** Schematic diagram of osmotic pressure mechanism.

So how is the osmotic pressure model constructed in the reservoir? As shown in Figure 4, a double ionosphere will be formed on the surface of the clay minerals after adsorbing ions. This kind of clay with a double ionosphere has the properties of a semi-permeable membrane. When the fluid injected into the reservoir has a lower salinity than the formation water, osmotic pressure will be formed on both sides of the clay, which will drive water molecules in low-salinity fluids to enter the formation through clay minerals, displacing oil phase production. This mechanism has been fully proved in subsequent experiments.

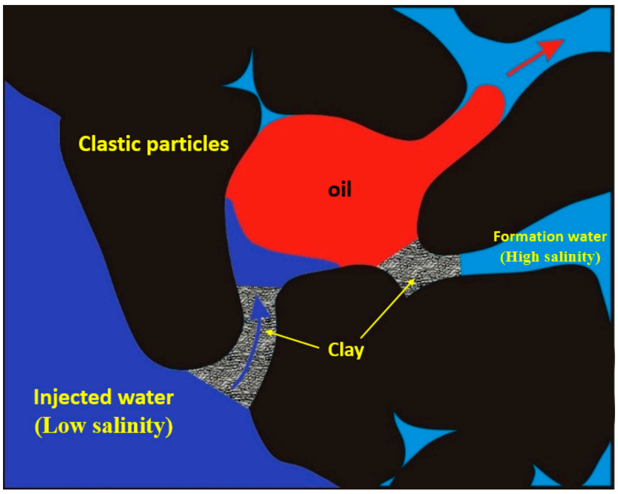



**Figure 4.** Schematic diagram of osmotic pressure flooding.

It can be seen that, on the one hand, salinity can significantly reduce the oil–water interfacial tension, and on the other hand, it can establish an osmotic pressure displacement model for oil displacement, which are the main ways to affect the imbibition process of tight sandstone reservoirs.

## 3. Experimental Process

In order to effectively distinguish the effect of salinity and capillary force and to better quantify the impact of salinity on the process of imbibition oil recovery, the design experiment is as follows.

The self-imbibition experimental device is shown in Figure 5, including a Mettler's high-precision balance (one-tenth of a million accuracy), cores, etc. When imbibition occurs, displacement occurs between the wetting phase and the non-wetting phase. The difference in the density of the two phases will cause the quality of the core to change. The difference is converted to the instantaneous fluid displacement amount, and the imbibition situation of the core can be obtained. The specific calculation is shown in Formulas (1) and (2).

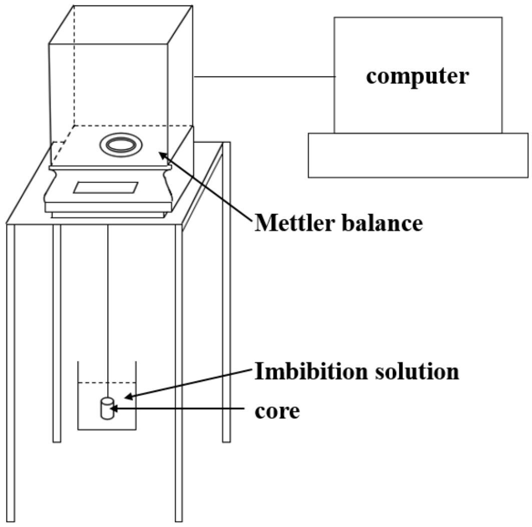



**Figure 5.** The experimental device.

The amount of oil produced by imbibition is:

$$M_o = \frac{M_0 - M_t}{\rho_w - \rho_o} \times \rho_o \tag{1}$$

The imbibition replacement rate is:

$$R = \frac{M_o}{\Delta M} \times 100\% \tag{2}$$

Among them, $M_0$ is the mass of the core at the beginning of imbibition, kg; $M_t$ is the mass of the core at time $t$, kg; $\rho_w$ and $\rho_o$ are the densities of the wetting and non-wetting phases, respectively, kg/m$^3$, $\Delta M$ is the core poor mass before and after saturation, kg.

The experimental environment is shown in Figure 6. The hydrophilic core is saturated with distilled water with a salinity of 0 mg/L, and the beaker is filled with high-salinity brine. Based on the analysis of the osmotic pressure mechanism, it can be known whether the salinity brine acts on the interfacial tension, or the osmotic pressure formed is opposite to the capillary force. By comparing the core self-imbibition curves with and without the influence of salinity, the influence of salinity on the process of imbibition oil recovery can be quantitatively characterized.

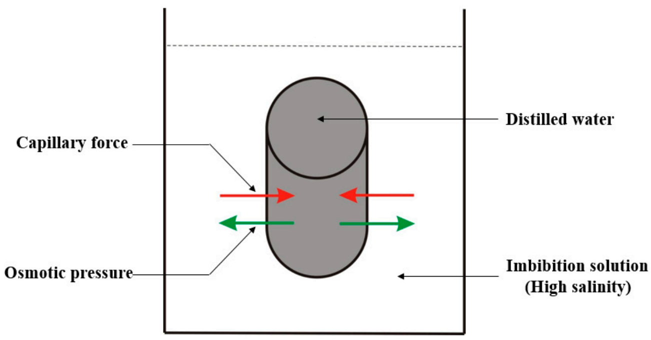



**Figure 6.** The experimental environment and force.

Repeat the experiment of washing oil saturation on the same core to ensure that the comparative analysis variable is single. The oil phase used is a simulated oil prepared with a 1:2 volume ratio of crude oil and kerosene in the target layer, whose viscosity at room temperature is 3.23 mPa·s; the water used is distilled water with an interfacial tension of 10.7 mN/m and brine with salinity of 15,000 mg/L and 45,000 mg/L, respectively. Please refer to the above for the preparation table. The specific steps are as follows:

① Cut the core to the target size, the length of the core is about 4 cm, the diameter of the core is 2.5 cm;

② Clean, wash, and dry the core to a constant weight;

③ The core is flooded with saturated distilled water, and the simulated oil, adding oil-soluble red dye to facilitate the observation of experimental phenomena, is used for the experiment. Reverse drive the saturated core to the same saturation and put it into a beaker containing simulated oil for the experiment to age for use;

④ Take out the core to be used and wipe off the surface oil, immerse the core in distilled water or configured salinity brine for imbibition experiments;

⑤ Record the experimental data until imbibition reaches a stable state, and calculate the imbibition replacement rate.

The experimental cores were taken from the CHANG-7 tight sandstone reservoir in the Changqing oilfield, consisting of four blocks with an average length of 4.37 cm, an average diameter of 2.50 cm, and a porosity range of 3.53% to 8.16% (the average porosity was 5.84%). The permeability ranged from 0.0280 mD to 0.1366 mD (the average permeability was 0.2899 mD), the absolute content of the clay was 2.11% to 10.05% (the average content of clay is 5.30%), the total amount of quartz in the core was 21% to 33%, and the content of feldspar was 35% to 51%. The content of total cuttings ranged from 10% to 30%, and the intercalation material was mainly carbonate intercalation material, which ranged from 0 to 12%. The core physical parameters are shown in Table 1. The intergranular pores and dissolved pores were not developed, and only a few cores had intergranular pores and dissolved pores.

**Table 1.** Table of core physical parameters.

| Number | Porosity/% | Average Air Permeability/$10^{-3}$ μm | Quartz/% | Feldspar/% | Carbonate Interstitial/% | Intergranular Pores/% | Total Dissolved Pores/% | Absolute Clay Content/% |
|---|---|---|---|---|---|---|---|---|
| 4 | 3.53 | 0.0413 | 23.0 | 51.0 | 0.0 | 0.0 | 0.0 | 3.24 |
| 9 | 7.39 | 0.0840 | 21.0 | 50.0 | 9.0 | 0.1 | 1.0 | 5.79 |
| 19 | 4.27 | 0.0280 | 22.0 | 39.0 | 0.0 | 0.0 | 0.0 | 10.05 |
| 46 | 8.16 | 0.1366 | 33.0 | 35.0 | 12.0 | 0.5 | 0.0 | 2.11 |

Generally speaking, the cores are dense, and the pore structure is complex, as shown in Figure 7. A high-pressure mercury injection curve of the four cores is shown in Figure 8. From the shape of the curve, it can be seen that the pore throats of the No. 46 core are more concentrated, the sorting is better, and the throat radius is larger, followed by the No. 9 core and the No. 4 core, and the No. 19 core has a smaller throat radius and the worst sortability.

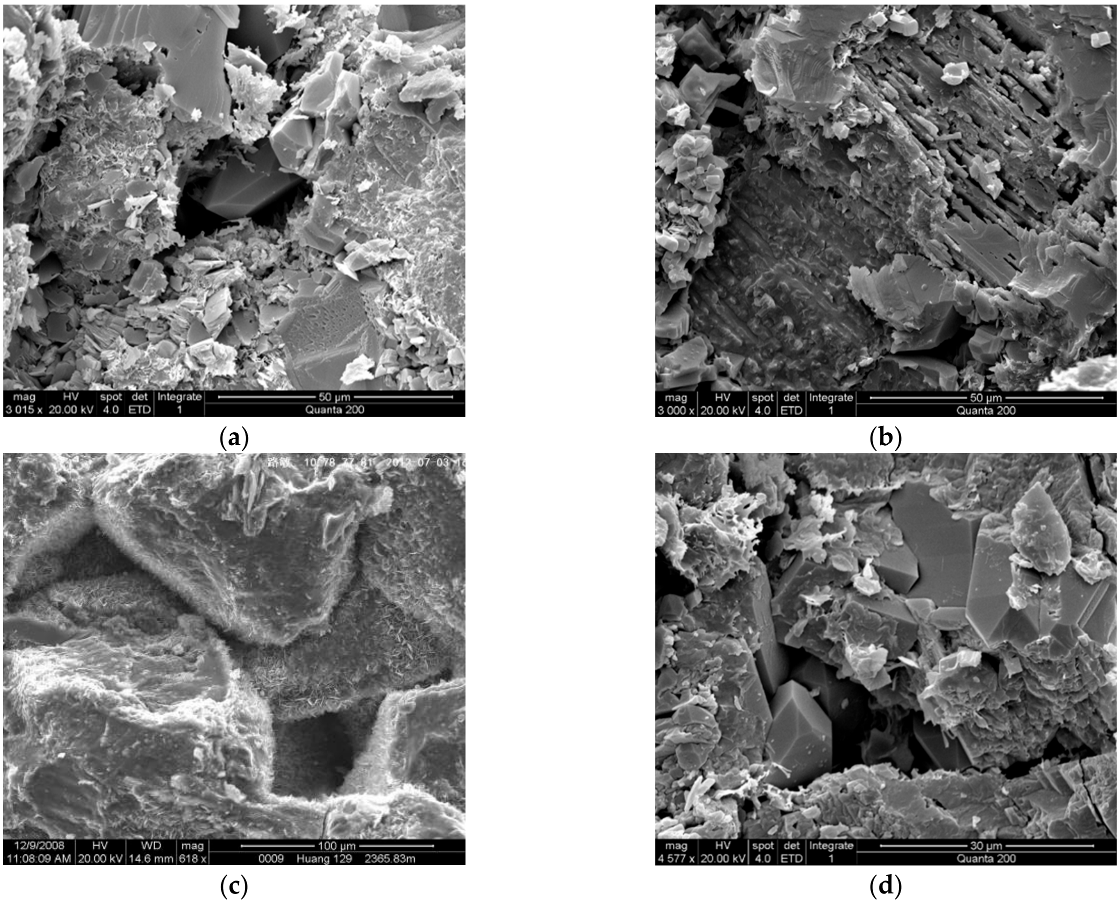



**Figure 7.** Core scanning electron microscopy results: (**a**) dissolved pores, intergranular pores (No. 4 core); (**b**) plagioclase pores (No. 46 core); (**c**) intergranular pores (No. 9 core); (**d**) quartz secondary enlargement (No. 9 core).

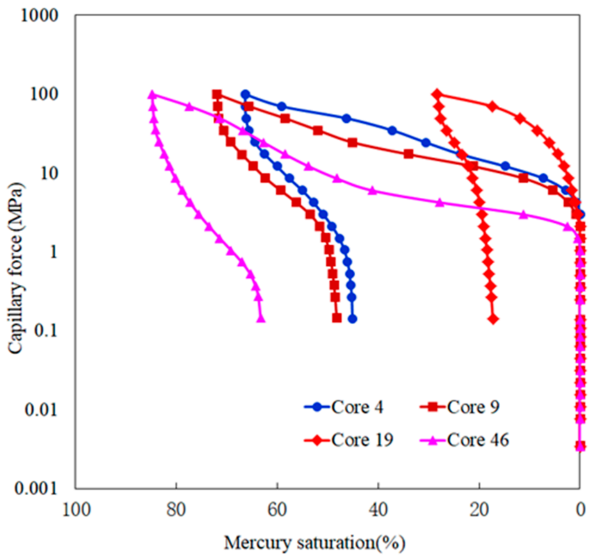



**Figure 8.** Mercury intrusion curves of four cores.

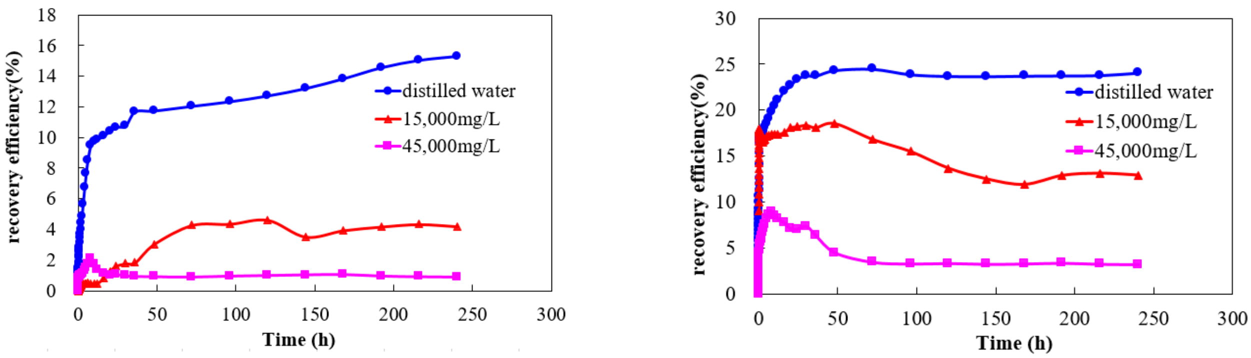
## 4. Result Analysis

The imbibition processes of the No. 9 core in distilled water, brine with a salinity of 15,000 mg/L, and brine with a salinity of 45,000 mg/L are shown in Figure 9. It can be seen that the simulated oil volume was replaced by the core in distilled water the most, followed by the brine with a salinity of 15,000 mg/L, while the amount of simulated oil replaced in the brine with a salinity of 45,000 mg/L is the least. This shows that the salinity can significantly inhibit the oil–water imbibition replacement efficiency, that is, the salinity has a significant impact on the imbibition process of tight sandstone cores.

(**a**) (**b**) (**c**)

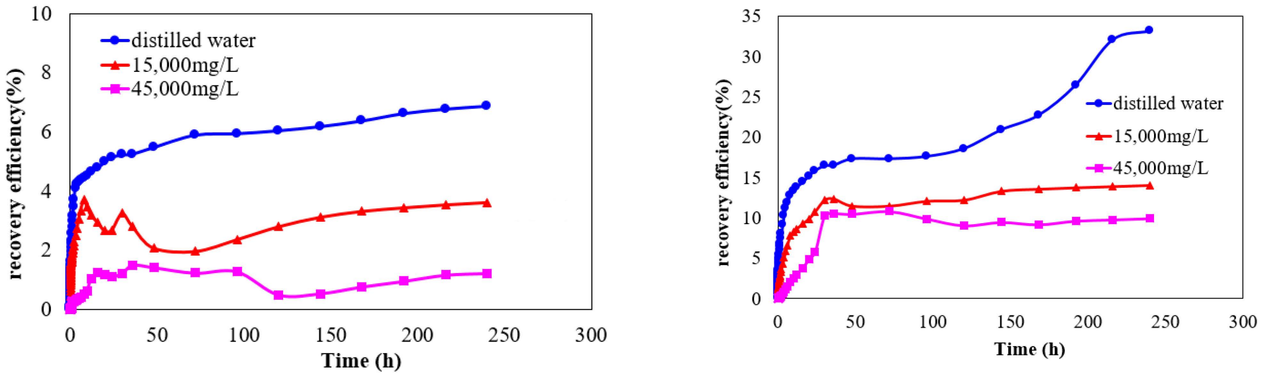
**Figure 9.** Imbibition process of No. 9 core: (**a**) distilled water imbibition; (**b**) the degree of salinity is 15,000 mg/L saline imbibition; (**c**) the degree of salinity is 45,000 mg/L saline imbibition.

The relationship between the imbibition displacement rate and time of the four cores in distilled water, brine with a salinity of 15,000 mg/L, and brine with a salinity of 45,000 mg/L is shown in Figure 10. As can be seen from the curve, the imbibition replacement rate of the core in distilled water is the highest, followed by that in brine with a salinity of 15,000 mg/L, and the imbibition replacement rate in brine with a salinity of 45,000 mg/L is the lowest, which is consistent with the core self-imbibition experimental phenomenon shown in Figure 9. The No. 46 core has the highest imbibition replacement rate both in distilled water and salinity brine, followed by No. 9 core and No. 4 core, and the lowest is No. 19 core. This indicates that the higher the permeability, the higher the imbibition displacement rate, that is, the imbibition displacement rate is positively correlated with the core permeability.




(**a**) (**b**)

**Figure 10.** *Cont.*




(**c**) (**d**)

**Figure 10.** The relationship between core imbibition replacement rate and time: (**a**) the relationship between the imbibition replacement rate of No. 4 core and time; (**b**) the relationship between the imbibition replacement rate of No. 9 core and time; (**c**) the relationship between the imbibition replacement rate of No. 19 core and time; (**d**) the relationship between the imbibition replacement rate of No. 46 core and time.

Comparing the core self-imbibition curve with and without the influence of the salt concentration difference, it can be seen that the effect of brine with a salinity of 15,000 mg/L in inhibiting oil–water imbibition is less than brine with a salinity of 45,000 mg/L. This shows that the greater the difference in salt concentration, the greater the impact of salinity on the process of imbibition oil recovery of tight sandstone reservoirs. As shown in Figure 11, compared with the replacement rate of distilled water, the imbibition replacement rate of brine with a salinity of 45,000 mg/L of the No. 46 core decreased by 23.23%, that of the No. 9 core decreased by 20.85%, that of the No. 4 core decreased by 14.40%, and that of the No. 19 core decreased by 5.65%. This shows that the greater the permeability, the greater the impact of salinity on the process of imbibition oil recovery of tight sandstone reservoirs.

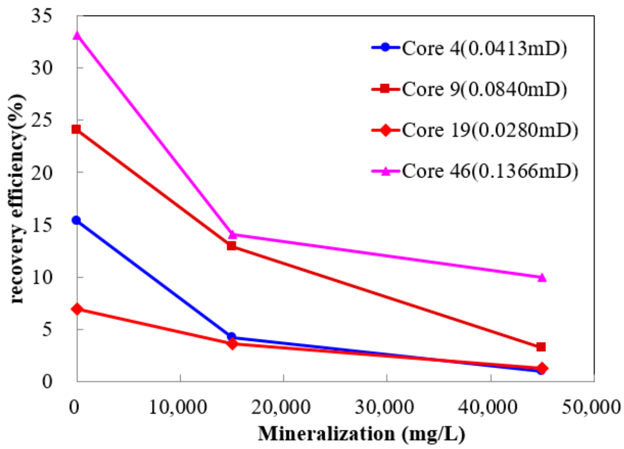



**Figure 11.** The relationship between the imbibition replacement rate and salinity of 4 cores.

It can be seen from the imbibition curve that, compared with the imbibition curve of distilled water, the imbibition curve of brine with salinity presents a certain fluctuation shape, that is, a curve decline stage, which is due to the difference between the capillary force and the time of controlling the salinity. At the initial stage of imbibition, all imbibition curves rise rapidly, which shows that the capillary force as the dominant force is greater than the salinity force. At the mid stage of imbibition, the imbibition curve shows a downward trend. This shows that the capillary force as the dominant force is greater than the capillary force. At the end of imbibition, the curve tends to be flat. This is because the fluid reaches the imbibition equilibrium at this stage, and the capillary force and salinity are not obvious.

## 5. Discussion

As an important mechanism to improve the oil recovery of low-permeability tight reservoirs, the effect of imbibition oil recovery is restricted by many factors. In this paper, taking the core of the CHANG-7 tight sandstone reservoir in the Changqing oilfield of the China National Petroleum Corporation as the research object, based on the principle that the action direction of salinity brine is always opposite to that of capillary force, an ingenious core spontaneous imbibition experimental device is designed to study the effect of salinity on the process of imbibition oil recovery in tight sandstone reservoirs. A series of spontaneous imbibition experiments were carried out using brines with different salinities. On the one hand, the effects of salinity and capillary force on the imbibition of tight sandstone cores were effectively distinguished. On the other hand, the effect of salinity on the spontaneous imbibition process of cores was characterized quantitatively. The research results show that there is a difference between the action time of capillary force and salinity. The salinity at the mid stage of imbibition is better than the capillary force, the high-salinity brine can significantly inhibit oil–water imbibition replacement, which has a significant impact on the process of imbibition oil recovery in tight sandstone cores. In the presence of high-efficiency surfactants, the salinity brine can significantly reduce the oil–water interfacial tension, which is not conducive to spontaneous imbibition. The adverse effect of salinity on imbibition oil recovery can be eliminated by adding surfactants. At present, our research mainly focuses on the effect of salinity on the process of imbibition oil recovery in tight sandstone reservoirs. In order to further clarify the mechanism of imbibition-enhanced oil recovery in low-permeability tight reservoirs, exploring how to adjust the optimal salinity of fracturing fluid to maximize the effect of imbibition after fracturing will be the focus of our future research.

## 6. Conclusions

In this paper, through a newly designed core self-imbibition experiment, the mechanisms of salinity are studied, the influence of salinity on the process of imbibition oil recovery is quantitatively characterized, and the following conclusions are obtained:

(1) The influence of salinity on the imbibition process of tight sandstone reservoirs is mainly acted through two ways: one is to reduce the fluid interfacial tension, and the other is to construct an osmotic pressure displacement model;
(2) Salinity has significant effects on interfacial tension. The interfacial tension of low-salinity brine is only 1/5 of that of distilled water. However, in the presence of high-efficiency surfactants, the effect of salinity on interfacial tension is not obvious;
(3) The imbibition process of tight sandstone cores is heavily influenced by the degree of salinity. The greater the difference in salt concentration, the greater the permeability, and the greater the influence of salinity on the process of imbibition oil recovery in tight sandstone reservoirs;
(4) At the initial stage of imbibition, the effect of salinity is less important than that of capillary force. At the mid stage of imbibition, the effect of salinity is much more important than that of capillary force and the imbibition curve shows a downward trend. At the end of imbibition, the fluid tends toward imbibition equilibrium, and the effects of capillary force and salinity are not obvious.

**Author Contributions:** Data curation, L.Y. and S.L.; writing—original draft preparation, X.L. and H.H.; writing—review and editing, Q.G. and Y.L. All authors have read and agreed to the published version of the manuscript.

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**Data Availability Statement:** Raw data and derived data supporting the findings of this study are available from the corresponding author Xiong Liu (Email: lx06106232@163.com) on request.

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