Influence of Sand Production Damage in Unconsolidated Sandstone Reservoirs on Pore Structure Characteristics and Oil Recovery at the Microscopic Scale

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ABSTRACT: Unconsolidated sandstone reservoirs have low rock strength and are easily damaged by sand production. To evaluate the effect of the microscopic pore system on the degree of recovery and sand production damage, five typical unconsolidated sandstone core samples were selected. The nuclear magnetic resonance $T_2$ spectrum of the water-flooding experiments was used to analyze the oil displacement mechanism and sand production damage of the pore throat structure, and the control mechanism of the injection parameters was used to evaluate the recovery and sand production damage degree. The results showed that the recovery of the unconsolidated sandstone core samples was the highest when the injection volume was 6 PV, and the overall pore throat recovery increased from 14.37 to 48.72%. The recovery and sand production damage increased with increasing injection pressure. The overall pore throat recovery was the highest when the pressure was 20 MPa (48.42%), and the sand production damage index was the maximum when the pressure was 25 MPa (19.98%). Under a lower injection pressure, sand production damage mainly originates from loose sand. The main target of loose sand production damage is a smaller pore throat, and the sand production index increases slowly. The recovery increased with the pressure and increased relatively quickly. Under a higher injection pressure, sand production damage mainly comes from loose sand and skeleton sand, causing damage to both smaller and larger pore throats. The sand production damage is positively correlated with injection pressure. The recovery slows down with an increase in pressure or even decreases.

1. INTRODUCTION

Unconsolidated sandstone reservoirs have shallow burial depths, poor cementation, large differences in reservoir petrophysical properties, complex pore throat structures, strong heterogeneity, and easy formation of favorable zones for oil and gas production and storage. However, with the progress of oilfield production operations, the drag force of the reservoir fluid on the rock skeleton particles increases, resulting in obvious sand production in the reservoir. Sand production in unconsolidated sandstone reservoirs results in lower rock strength. Meanwhile, the permeability is reduced, the microscopic pore throats are blocked by sand particles, and the dominant seepage channel for crude oil is reduced. Improving single-well productivity under the premise of effective sand control is the key to the development of unconsolidated sandstone reservoirs. Fan et al. believed that fracturing and packing technology can effectively control sand and increase production by changing the migration state of oil and water. Walters et al. believed that by forming short and wide fractures and filling with a high sand ratio in the reservoir, a bilinear flow of reservoir fluid can be formed near high-conductivity fractures, and the formation of sand production can be alleviated. Huang et al. first proposed the use of nanoparticles to prevent the migration of reservoir particles using special nanoparticles (nanocrystals) to immobilize the reservoir particles in the hydraulic fracturing pack. Shakiba et al. believe that nanoparticles can not only control sand and increase production but also increase rock strength. Water flooding remains the main method for unconsolidated sandstone reservoir development. Previous research results suggest that measures such as profile control, plugging of high-permeability layers, fracturing, and sand packing can increase the sweep coefficient and improve oil production. However, there are few studies on the sand production damage mechanism of unconsolidated sandstone. In addition, scholars have carried out research on the microscopic pore-throat characteristics of unconsolidated sandstone reservoirs.

Received: August 22, 2022
Accepted: October 20, 2022
Published: October 28, 2022
2. EXPERIMENTAL SECTION

2.1. Materials. The core samples are from the unconsolidated sandstone of the Toutunhe Formation in the North 10 block of the Junggar Basin. The samples are cylinders with a length of 5 cm and a radius of 2.5 cm. The porosities are between 19.58 and 21.57%, and the permeabilities are between 32.59 and 37.25 mD (Table 1).

The experimental water was simulated formation water with a salinity of 20,000 mg/L. The experimental oil used was a combination of crude oil and aviation kerosene. The density of the oil is 0.92 g/cm³, and the viscosity of the oil sample is 223 mPa·s.

2.2. Experimental Setup. The main equipment used in the experiments included an NMR instrument and a displacement pump. The NMR instrument used was the Mini-MR instrument manufactured by Shanghai Niumai. The magnetic field intensity, resonance frequency (RF), RF pulse frequency range, and RF frequency control accuracy are 0.5, 10, 1−30, and 0.01 MHz, respectively. The displacement pump is a 260D high-pressure metering pump produced by Teledyne Isco, USA. The displacement pump was a double-pump body, and each pump body had a volume of 103 mL. The continuous-flow velocity range of the displacement pump was 0.001−80 mL/min, the measurement scale was accurate, and the pump could be injected continuously. In the experiments, it was mainly used to inject simulated formation water, manganese water, and crude oil, among others, into the cores.

The porosity was tested by the vacuum saturator, and the permeability was tested by the gas permeability tester, both manufactured by Huaxing Petroleum Instrument Co., Ltd. Other experimental instruments include the electronic balance manufactured by Huaxing Petroleum Instrument Co., Ltd, the electronic balance manufactured by Huaxing Petroleum Instrument Co., Ltd, and the Mn²⁺ solution (manganese water) with a salinity of 25,000 mg/L. The Mn²⁺ solution (manganese water) with a salinity of 25,000 mg/L was used to displace the simulated formation water in the cores. After the injection volume was 3−4 PV, NMR was performed to observe the effect of water signal elimination. Next, the core samples of saturated crude oil were tested by NMR, and the original oil–water distribution characteristics were recorded as the T₂ spectrum of the initial state of the core. The displacement velocity was set to 0.10 mL/min, and the control mechanism of the injection parameters on the oil recovery and sand production damage.

### Table 1. Petrophysical Properties of the Five Samples

| number | length/cm | diameter/cm | porosity/% | permeability/mD | pressure/MPa |
|--------|-----------|-------------|------------|----------------|-------------|
| N1     | 5.2       | 2.52        | 19.58      | 33.70          | 5           |
| N2     | 5.1       | 2.50        | 20.05      | 32.59          | 10          |
| N3     | 5.2       | 2.50        | 20.28      | 35.28          | 15          |
| N4     | 5.0       | 2.51        | 19.52      | 36.85          | 20          |
| N5     | 5.1       | 2.50        | 21.57      | 37.25          | 25          |
injection volumes. According to the principle of the NMR test, oil recovery is defined as the ratio of the difference between the $T_2$ spectrum and the envelope area of the horizontal axis before and after the experiment and the $T_2$ spectrum of the initial state and the envelope area of the horizontal axis. According to this method, the oil recovery of different pore throat ranges can be calculated, and the microscopic mechanism of water displacement in unconsolidated sandstone can be quantitatively evaluated.

The $T_2$ spectrum difference between the first saturation state and the second saturation state of core samples was compared, the fluid distribution in the pore throat was analyzed, and the damage degree of sand production in the reservoir was quantitatively evaluated. The experimental flowchart is shown in Figure 1.

### 2.4. Sand Production Mechanism

#### 2.4.1. Sand Production Damage Index

NMR technology can reflect the occurrence of fluid in pore throats of different sizes. Therefore, we used NMR technology to quantitatively evaluate the sand production characteristics and microscopic mechanisms of unconsolidated sandstone reservoirs during water flooding. As shown in Figure 2, the initial saturated crude oil in the pore throat with a radius of $10^{-1} - 10^{-2}$ ms is represented by $(S_i)$, the resaturated oil in this area after water flooding is represented by $S_o$, and the damage degree of sand production in unconsolidated sandstone can be calculated as follows:

$$ b = \frac{S_i - S_o}{S_i} \times 100\% $$

where $b$ is the damage degree of sand production (%), $S_i$ is the $T_2$ spectrum frequency area of the secondary saturated oil, and $S_o$ is the $T_2$ spectrum frequency area of the initial saturated oil. Therefore, the higher the sand production damage index, the greater the sand production damage of the reservoir.

This article analyzes and evaluates the sand production index of the overall pore throat, smaller pore throat, and larger pore throat. According to the classification methods of some scholars, the trough position of the NMR $T_2$ spectrum of the first saturated water of the core sample is used as the boundary position between the smaller pore throat and the larger pore throat.

#### 2.4.2. Microscopic Sand Production Mechanism

According to the microstructure of unconsolidated sandstone, the rock particles of sandstone are divided into two types: skeletal sand and loose sand. Loose sand exists in the pore throat system or seepage channels of the unconsolidated sandstone reservoirs. With reservoir development, loose sand is carried to the wellbore under the action of formation fluids, causing sand production in the oil well; the amount of sand produced by loose sand is small. The sand particles peeled off from the skeleton sand and became loose sand. Sand production caused by the peeling off of the skeleton sand particles often leads to the destruction of the rock structure, resulting in a large amount of sand production in the oil well (Figure 3).

### 3. RESULTS

#### 3.1. Recovery

After the injection volume was $0-2$ PV, the NMR $T_2$ spectrum was shown as a red curve in Figure 4. We compare the difference in the undercover area between the red curve and the black curve; the black curve represents the initial state. The water at this stage mainly displaces the crude oil within the range of $0.1-2.33$ ms from the smaller pore throat, and the oil volume of the larger pore throat remained basically unchanged. After the injection volume is $2-4$ PV, the NMR $T_2$ spectrum is shown as a blue curve. On comparing the difference of the undercover area between the blue curve and the red curve, the remaining oil in the $2.23-258.64$ ms range decreases, indicating that the injected water has begun displacing the oil in the larger pore throat. The amount of remaining oil in the smaller pore throats increases. It is assumed that the crude oil in the larger pore throats stays in the smaller pore throats during the displacement process and cannot flow further. As a result, the remaining oil in the smaller pores does not increase but decreases. When the injection

![Figure 1. Experimental flowchart of water flooding sandstone samples.](https://doi.org/10.1021/acsomega.2c05357)

![Figure 2. Calculation of the damage degree of pore throat sand production.](https://doi.org/10.1021/acsomega.2c05357)
volume reaches 6 PV, the remaining oil of the larger and smaller pores is reduced, and the recovery of the larger pore throats is better than that of the smaller pore throats. The oil recovery of the N1 core sample at injection volumes of 2, 4, and 6 PV is 4.66, 8.88, and 14.37%, respectively.

As shown in Figure 5, after the injection volume was 0–2 PV, the distribution of crude oil with larger pore throats decreased significantly, and the range was mainly between 12.0 and 130.0 ms. The distribution of crude oil in the smaller pore throats did not change, and the amount of oil in the area where the larger and smaller pores were connected increased. After the injection volume was 2–4 PV, the remaining oil of larger pore throats and smaller pore throats decreased significantly, indicating that the recovery in the overall pore throat range was higher. When the injection volume reached 6 PV, the remaining oil of the larger pore throats decreased while that of the smaller pore throats decreased to a limited extent, and the recovery of smaller pore throats was close to that of 4 PV. The oil recovery of the N2 core sample at injection volumes of 2, 4, and 6 PV were 1.43, 18.07, and 23.15%, respectively.

As shown in Figure 6, after the injection volume is 0–2 PV, the crude oil in the range of 3.87–59.95 ms with a larger pore throat is mainly used, while the remaining oil of the smaller pore throat is basically unchanged. After the injection volume is 2–4 PV, the reduction of remaining oil in the range of 3.87–59.95 ms for the larger pore throats is obvious, indicating that the injected water is still mainly used to displace the crude oil in the larger pore throats. The remaining oil of 0.1–3.87 ms also decreases, but the decrease is smaller. When the injected water volume reaches 6 PV, the remaining oil of the larger pore throats appears to significantly reduce, and the recovery of the smaller pores was significantly lower. The oil recovery of the N3 core sample at injection volumes of 2, 4, and 6 PV is 7.40, 21.20, and 42.59%, respectively.

As shown in Figure 7, the injection pressure of the N4 core sample was 20 MPa. After the injection volume was 0–2 PV, the crude oil content of the larger pore throats and smaller pore throats both decreased significantly; this phenomenon is relatively rare in other core samples. After the injection volume was 2–4 PV, the remaining oil in different pore throats varied slightly, indicating that the recovery was not significantly improved compared to the previous stage. When the injected volume reached 6 PV, the remaining oil of the larger pore throat (3.22–774.26 ms) was significantly reduced. The remaining oil of the smaller pore throat of 0.1–3.22 ms has a limited decrease, and the recovery is close to that of 4 PV.

Figure 3. Sand production mechanism of an unconsolidated sandstone reservoir.

Figure 4. NMR T₂ spectrum of core sample N1.

Figure 5. NMR T₂ spectrum of core sample N2.

Figure 6. NMR T₂ spectrum of core sample N3.
The oil recovery of the N4 core sample at injection volumes of 2, 4, and 6 PV is 22.79, 30.49 and 48.42%, respectively. The NMR T$_2$ spectrum of the N5 core sample is shown in Figure 8. The smaller pore throat size is in the range of 0.1−6.69 ms, and the larger pore throat is in the range of 6.69−372.76 ms. The relative content of the smaller and larger pore throat is 28.91 and 71.09%, respectively. Larger pore throats have a high content, and smaller pore throats have a relatively low content. The injection pressure of the N5 core sample is 25 MPa. After the injection volume was 0−2 PV, the crude oil content of the pore throats decreased, and the peak value of the T$_2$ spectrum shifted to the left. After the injection volume was 2−4 PV, the remaining oil in the larger pore throat varied greatly, and the remaining oil in the smaller pore throat hardly changed, indicating that the main available pore throat range at this stage was in the larger pore range. When the injected water volume reached 6 PV, the crude oil content of pore throats decreased. At a higher injection volume, the remaining oil in the smaller pore throat began to be used, and the remaining oil in the range of the larger pore throat decreased significantly. The oil recovery of the N5 core sample at injection volumes of 2, 4, and 6 PV were 12.15, 19.88, and 45.76%, respectively.

In summary, the recoveries of the five unconsolidated sandstone core samples increased as the injection pressure and injection volume increased. At a lower injection pressure and injection volume, the recovery of the larger pore throat was higher, and a considerable amount of oil remained in the smaller pore throat. At a higher injection pressure and injection volume, the crude oil in the smaller pore throat can be used, and the recovery of the larger pore throat is still higher, but the increased rate of recovery slows down.

### 3.2. Sand Production Damage.

The NMR T$_2$ spectrum of core sample N1 is shown in Figure 9. The injection pressure is 5 MPa, and the NMR T$_2$ spectrum of the first and second saturated crude oil is basically unchanged in the larger pore throat range of 2.23−258.64 ms. There is no obvious sand production damage in the larger pore throat. However, the NMR T$_2$ spectrum decreases in the small pore throat range of 0.1−2.23 ms, and the decrease is not obvious. After water flooding, the smaller pore throats caused sand production damage, but the damage was relatively low.

The NMR T$_2$ spectrum of the core sample N2 is shown in Figure 10. In the small pore throat range of 0.1−8.03 ms, the T$_2$ spectrum of the secondary saturated oil shifts to the right. Under a 10 MPa injection pressure, the content of smaller pore throats decreased, possibly owing to blockage by sand particles. Compared with the larger pore throat range of 8.03−774.26
ms, the $T_2$ spectrum of the secondary saturated oil has no obvious change. After water flooding, the phenomenon of sand production damage with larger pore throats under a 10 MPa injection pressure is not obvious.

The NMR $T_2$ spectrum of core sample N3 is shown in Figure 11. Different from the core sample N1 and core sample N2, the $T_2$ spectrum of the secondary saturated oil decreased slightly in the smaller pore throat range of $0.1−3.87$ ms. In the larger pore throat range of $3.87−59.95$ ms, the $T_2$ spectrum of the secondary saturated oil also showed a significant drop. Therefore, the comprehensive analysis shows that under an injection pressure of 15 MPa, obvious sand production damage began to occur inside the larger pore throat.

The NMR $T_2$ spectrum of core sample N4 is shown in Figure 12. The $T_2$ spectrum decreased in the smaller pore throat range of $0.1−3.22$ ms and the larger pore throat range of $3.22−774.26$ ms. The pore throat area where the NMR $T_2$ spectrum changes increases. As the injection pressure increases, more pore throats of unconsolidated sandstone are damaged by sand production. The sand production damage of the larger pore throats is more obvious. Smaller pore throats of $0.1−1$ ms are damaged by sand production, but the overall damage is lower.

Figure 11. Sand production damage degree of core sample N3.

Figure 12. Sand production damage degree of core sample N4.

The NMR $T_2$ spectrum of core sample N5 is shown in Figure 13. The $T_2$ spectrum decreased in the smaller pore throat range of $0.1−6.69$ ms and the larger pore throat range of $6.69−372.76$ ms. Compared with the core sample N4, the smaller pore throat of $0.1−1$ ms is continuously damaged by sand production. In the larger pore-throat scale range, the NMR $T_2$ spectrum curve shifts to the right, indicating that more large pores are damaged. Under an injection pressure of 25 MPa, sand with a larger particle size is peeled off, which makes the size of some pore throats larger, forming an illusion of improving the microscopic pore throat structure. The peeling of sand particles leads to poorer rock cementation, weaker rock strength, and more severe sand production damage. Sand particles block the pore throats during the migration process, forming “dead holes” and “blind holes” and decreasing the seepage capacity.

As the injection pressure increased, the NMR $T_2$ spectrum characteristics of the five unconsolidated sandstone core samples showed that at lower injection pressures, the smaller pore throats were first damaged by sand production, the pore throat size decreased, and some pore throats were blocked by sand. Under higher injection pressures, larger pore throats began to be damaged by sand production. The larger pore throats of the five core samples were higher, and sand with a larger particle size was stripped. As the fluid enters the dominant seepage channel first, the damage degree of the larger pore throat becomes greater than that of the smaller pore throat.

The five unconsolidated sandstone samples N1, N2, N3, N4, and N5 increased with injection volume, and the recovery increased from 4.66 to 14.37%, 1.43 to 23.15%, 7.40 to 42.59%, 22.79 to 48.42%, and 12.15 to 45.76%, respectively. With the injection pressure increase, the recovery increased from 14.37 to 48.42% and then decreased to 45.76%. The degree of damage to sand production increased from 2.55 to 19.98%. The recovery was the highest under a 20 MPa injection pressure, and the degree of damage to sand production was the highest under a 25 MPa injection pressure (Table 2).

4. DISCUSSION

4.1. Recovery and Injection Volume. The recovery of core samples under different injection volumes is shown in

Figure 13. Sand production damage degree of core sample N5.
In the low-pressure range of 5 MPa, the overall pore throat and larger pore throat did not increase significantly. In the high-pressure range, the recovery of the overall pore throat, larger pore throat, and smaller pore throat increased with the increase in injection pressure. The recovery of the larger pore throat was 1.88–24.64%, and 14.82–40.00%, respectively. In the lower pressure range, the recovery of the overall pore throat increased with increasing injection pressure, and the recovery of the larger pore throat increased. Evidently, the recovery of smaller pore throats still increased substantially as the injection pressure increased. In the high-pressure range, the recovery of the overall pore throat and larger pore throat increased with increasing injection pressure. The recovery of the smaller pore throat increased with increasing injection pressure. The recovery of the N5 core was lower than that of N4.

When the injection volume was 6 PV, the recovery of the core samples’ overall pore throat, smaller pore throat, and larger pore throat were 18.26–48.42%, 1.88–24.64%, and 14.82–40.00%, respectively. In the lower pressure range, the recovery of the overall pore throat increased with increasing injection pressure, and the recovery of the larger pore throat increased. Evidently, the recovery of smaller pore throats still increased substantially as the injection pressure increased. In the high-pressure range, the recovery of the overall pore throat and larger pore throat increased with increasing injection pressure. The recovery of the smaller pore throat increased with increasing injection pressure.

Overall, as the injection pressure increases, the recovery of the core samples increases. The main reason restricting the recovery increase is the larger pore throats. There was no obvious correlation between the recovery of the larger pore throats and the injection pressure. In the high-pressure range, the recovery of larger pore throats decreased with increasing injection pressure.

4.3. Sand Production Damage and Injection Pressure.

The five typical core samples of unconsolidated sandstone have similar physical properties. When the experimental conditions such as injection pressure are the same, we believe that the difference in the sand production index of the core samples is mainly due to the difference in the injection pressure of the five core samples. The control mechanism of injection pressure on sand production damage is evaluated through an in-depth analysis of experimental data. The sand production damage under different injection pressures is shown in Figure 16. The sand production damage of the five unconsolidated sandstone core samples ranged between 2.55 and 19.98%. With an increase in the injection pressure, sand production damage increased. In the low-pressure range of 5–10 MPa, the overall pore throat, smaller pore throat, and larger pore-throat sand
Production damages ranged from 2.55 to 4.14%, 2.07 to 4.01%, and 0.13 to 0.47%, respectively. The sand production damage of the smaller pore throats was obvious. In the high-pressure range of 15−25 MPa, the overall pore throat, smaller pore throat, and larger pore throat sand production damage ranged from 10.23 to 19.98%, 5.19 to 10.33%, and 5.33 to 10.41%, respectively. The sand production damage of smaller pore throats continues to increase, the sand production damage of larger pore throats begins to appear, and the sand production damage exceeds that of smaller pore throats. In summary, during the water-flooding process, when the injection pressure is low, loose sand in the porous medium or seepage channel of the unconsolidated sandstone reservoir is first carried by the fluid, thereby causing sand production. The particle size of loose sand is generally small as the fluid enters the smaller and larger pore throats during the flow process. A larger pore throat was the dominant channel for water flooding, and the retained...
loose sand was easily carried out during the water flooding process. Therefore, the main target of sand damage under low injection pressure is a smaller pore throat. As the injection pressure increased, the sand particles peeled off from the skeleton sand and became loose sand, which was then carried by the fluid, leading to sand production. The loose sand stripped from the skeleton sand contained sand grains with larger particle sizes. Owing to the small pore size of the smaller pore throat, this part of the sand particles was retained in the larger pore throat. Loose sand with a smaller particle size continues to stay in the smaller pore throat, and sand production under high pressure causes damage to both the smaller pore throat and the larger pore throat. Loose sand with a smaller particle size can easily move with the fluid, while loose sand with a large particle size peeled off from the skeleton sand stays in the larger pore throat and is not easy to carry out with the fluid. In addition, when the particles on the skeleton sand are peeled off, the stress balance between the original skeleton sand particles will be broken, and the degree of rock cementation will become worse, which will further aggravate sand damage. The sand production damage of larger pore throats restricts the recovery.

4.4. Recovery and Sand Production Damage. The relation between recovery and sand production damage is shown in Figure 17. The overall pore throat recovery of the five unconsolidated sandstone samples was the highest (48.42%) when the injection pressure was 20 MPa. The sand production damage was maximum (19.98%) when the injection pressure was 25 MPa. Under a lower injection pressure, the recovery rate increased as the pressure increased. Under a higher injection pressure, the recovery increased slowly with an increase in pressure or even decreased. This is because the sand production damage continues to increase with increasing injection pressure, restricting the oil displacement efficiency.

The recovery of five unconsolidated sandstone samples with smaller pore throats was the highest at 15 MPa (24.64%), and the sand production was the highest at 25 MPa (12.56%). There was no obvious correlation between the recovery of smaller pore throats and sand production damage. A possible reason for this is that more factors influence the recovery of smaller pore throats. In addition to sand production damage from unconsolidated sandstone, water- and velocity-sensitivity damage may affect the recovery of smaller pore throats.

The recovery of the five unconsolidated sandstone samples with larger pore throats was the highest at 20 MPa (40.00%), and the sand production was the highest at 20 MPa (10.41%). The injection pressure was 5–15 MPa, and the recovery of larger pore throats increased slowly with increasing pressure. The injection pressure rises from 15 to 20 MPa, and the recovery of larger pore throats increased significantly. The injection pressure rises from 20 to 25 MPa, and the recovery began to decline (Table 3). The recovery and sand production damage of larger pore throats increased with increasing injection pressure. However, after reaching a certain pressure,
the pore throat damage caused by sand production was obvious. Even if the sand production damage index no longer increases, an increasing number of large pore throats are blocked, directly limiting the increase in recovery. In particular, the sand particle blockage in larger pore throats is mainly loose sand, which is stripped from the skeleton sand. The damage caused by the sand production of the skeleton sand makes the unconsolidated characteristics of the unconsolidated sandstone more obvious, aggravates the sand production damage, and further aggravates the reduction in the recovery in the larger pore throat.

5. CONCLUSIONS

1. The recovery of the unconsolidated sandstone core sample was highest when the injection volume was 6 PV. The recovery of the overall pore throat, smaller pore throat, and larger pore throat ranges from 14.37 to 48.72%, 1.48 to 24.64%, and 12.89 to 40.00%, respectively. The recovery increases with an increase in the injection pressure. When the injection pressure was 20 MPa, the recovery of the overall pore throat was the highest at 48.72%. The main factor restricting the recovery is the larger pore throat, and there is no obvious positive correlation between the recovery of the larger pore throat.

2. The sand production damage of the unconsolidated sandstone core samples increased with an increase in injection pressure. The injection pressure increased from 5 to 25 MPa, and the sand production damage of the overall pore throat, smaller pore throat, and larger pore throat was 2.55–19.98%, 2.07–12.56%, and 0.13–10.41%, respectively. When the injection pressure is lower, the core sand damage mainly comes from loose sand, and the main target of sand damage is smaller pore throats. When the injection pressure is higher, sand production damage mainly comes from loose sand and skeleton sand, causing damage to both the smaller and larger pore throats.

3. The overall pore throat recovery of the unconsolidated sandstone core samples was the highest (48.42%) when the injection pressure was 20 MPa. The sand production damage was maximum (19.98%) when the injection pressure was 25 MPa. At lower injection pressures, the sand production damage index increased slowly, and the recovery increased faster with increasing pressure. In the higher injection pressure range, the sand production damage index continued to increase. Meanwhile, the increase in recovery slows or even decreases.

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Notes
The authors declare no competing financial interest.

■ ACKNOWLEDGMENTS

This research was sponsored by the PetroChina Innovation Foundation (no. 2020D-5007-0205), National Natural Science Foundation of China (no. 52004222), Scientific Research Program Funded by Shaanxi Provincial Education Department (Program 22JY054), The Youth Innovation Team of Shaanxi Universities, and the Scientific Research Program Funded by Shaanxi Provincial Education Department (Program no. 21JZ095).

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