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# Study on the Influential Factors of $CO_2$ Storage in Low Permeability Reservoir

**Ping Yue [1,2,*], Rujie Zhang [1], James J. Sheng [3], Gaoming Yu [4] and Feng Liu [5]**

[1] State Key Laboratory of Reservoir Geology and Development, Southwest Petroleum University, Chengdu 610500, China; zrj1999@126.com
[2] Institute of Unconventional Oil and Gas Science and Technology, China University of Petroleum (Beijing), Beijing 102249, China
[3] Institute of Petroleum Engineering, Texas Tech University, Broadway, Lubbock, TX 79409, USA; James.Sheng@ttu.edu
[4] Research Institute of Exploration and Development, Changqing Oilfield Company, PetroChina, Xi'an 710018, China; fyyp1983@126.com
[5] School of Petroleum Engineering, Xi'an Shiyou University, Xi'an 710065, China; xsyuliufeng@163.com
* Correspondence: yuepingaa@126.com; Tel.: +86-130-8804-0285

**Abstract:** As the demands of tight-oil Enhanced Oil Recovery (EOR) and the controlling of anthropogenic carbon emission have become global challenges, Carbon Capture Utilization and Sequestration (CCUS) has been recognized as an effective solution to resolve both needs. However, the influential factors of carbon dioxide ($CO_2$) geological storage in low permeability reservoirs have not been fully studied. Based on core samples from the Huang-3 area of the Ordos Basin, the feasibility and influential factors of geological $CO_2$ sequestration in the Huang-3 area are analyzed through caprock breakthrough tests and a $CO_2$ storage factor experiment. The results indicate that capillary trapping is the key mechanism of the sealing effect by the caprock. With the increase of caprock permeability, the breakthrough pressure and pressure difference decreased rapidly. A good exponential relationship between caprock breakthrough pressure and permeability can be summarized. The minimum breakthrough pressure of $CO_2$ in the caprock of the Huang-3 area is 22 MPa, and the breakthrough pressure gradient is greater than 100 MPa/m. Huang-3 area is suitable for the geological sequestration of $CO_2$, and the risk of $CO_2$ breakthrough in the caprock is small. At the same storage percentage, the recovery factor of crude oil in larger permeability core is higher, and the storage percentage decreases with the increase of recovery factor. It turned out that a low permeability reservoir is easier to store $CO_2$, and the storage percentage of carbon dioxide in the miscible phase is greater than that in the immiscible phase. This study can provide empirical reference for caprock selection and safety evaluation of $CO_2$ geological storage in low permeability reservoirs within Ordos Basin.

**Keywords:** carbon dioxide; storage capacity; oil recovery factor; low permeability reservoirs

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**Citation:** Yue, P.; Zhang, R.; Sheng, J.J.; Yu, G.; Liu, F. Study on the Influential Factors of $CO_2$ Storage in Low Permeability Reservoir. *Energies* **2022**, *15*, 344. https://doi.org/10.3390/en15010344

Academic Editors: Sai Wang, Wei Jia, Jiawei Tu and Xincheng Wan

Received: 16 November 2021
Accepted: 13 December 2021
Published: 4 January 2022

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## 1. Introduction

Human activities and the combustion of fossil fuels have released a large amount of carbon dioxide into the air. The resulting greenhouse effect has severely affected the earth's environment, on which human beings depend [1,2]. The underground geological storage of carbon dioxide is one of the most effective methods of managing carbon dioxide, that is, a method through which carbon dioxide is captured and injected into deep formation with appropriate storage conditions. Carbon dioxide storage includes reservoir storage, deep saline aquifer storage, and coal seam storage [3,4]. On the one hand, it can improve the recovery of oil and gas reservoirs and reduce the treatment cost of carbon dioxide. On the other hand, it can reduce the emission of carbon dioxide into the atmosphere. Many CCUS demonstration projects have been successfully implemented in the world, such as

$CO_2$ that has been sequestrated in Weyburn oilfield in Canada and $CO_2$ stored in the saline aquifer of the Sleipner gas field in Norway and the In Salah gas field in Algeria [5–7]. For this novel technology, the focus should be mainly on the safety and permanent storage of carbon dioxide.

After $CO_2$ is injected, if the $CO_2$ escapes through the caprock, it will lead to the following serious consequences: (1) If the $CO_2$ escapes to the surface, it may cause surface uplift or collapse which causes damages to surface constructions; (2) If $CO_2$ leakage occurs in the ocean, it may change the pH value of the water and destroy the marine ecological environment; (3) If $CO_2$ is transferred into the drinking water aquifer, it will endanger the life and health of local residents; (4) If a large $CO_2$ leakage occurs, the original intention of human beings to sequestrate $CO_2$ to reduce the greenhouse gas impact will be defeated [8–12]. Dian Fan et al. [13]. proposed an apparent liquid permeability model for heterogeneous and rough nanoporous tight matrices; Wang Chuansheng et al. [14] studied the carbon dioxide storage potential of the oil field in the Subei Basin based on the geologic structural conditions; D. Nicolas Espinoza et al. [15] proposed that the "sealing number" and the "stability number" might provide a rapid assessment of potential storage sites; Ernest N. Mbia et al. [16] studied the influence of caprock compressibility and permeability and the consequences for pressure development have been studied for the Vedsted structure, Furthermore, II Hong Min et al. [17] demonstrate that the flow instability in $CO_2$ transportation and injection systems can be avoided by maintaining the proposed conditions. Zheng Wei et al. [18] applied ABAQUS software to study the influence of caprock permeability on carbon dioxide storage; whereas F. Gumrah et al. [19] used CMG software to study the $CO_2$ storage in the reservoir and analyzed the effects of temperature, pressure, and porosity on the $CO_2$ storage in single-layer reservoir and multi-layer reservoirs; Sherif Fakher et al. [20] studied the storage factor of carbon dioxide cyclic injection in shale reservoirs and its impact on EOR potentials, and they concluded that increasing the injection pressure and reducing the temperature of carbon dioxide can increase the injected carbon dioxide. Rahmad Syah et al. [21] studied the effects of continuous carbon dioxide injection, water alternating gas injection, and cyclic carbon dioxide injection on EOR. The research shows that oil recovery achieved through circulating carbon dioxide injection is the highest, and the higher the recovery of crude oil, the more carbon dioxide is stored. The amount of $CO_2$ storage in a CCUS project may also be affected by geochemical and geomechanical reactions. Adu-Gyamfi et al. [22] studied the hydrodynamic, geochemical, and geomechanical effects separately with different combinations. They concluded that without considering the geochemical and geomechanical effect, the potential of $CO_2$ storage volume may be overestimated. It can be seen from the above research that many scholars found, from different perspectives, that geological sequestration is one of the most effective methods to manage carbon dioxide emission. Especially for oil reservoirs, it can also improve oil recovery. Because the leakage of $CO_2$ is closely related to the storage mode and mechanism, and there are few studies on the impact of $CO_2$ storage in low-permeability reservoirs thus far, the influential factors are not yet clear.

The geological sequestration of carbon dioxide in low permeability reservoirs has the following advantages [23,24]: (1) the geological characteristics are simple, and there are more pores to store $CO_2$ after the oil and gas reservoir is depleted; (2) The trapping mechanism is reliable, and the geologic structure that preserves oil and gas should also be able to store $CO_2$; (3) The injected carbon dioxide produces more crude oil in miscible and immiscible manners. Therefore, taking the Huang-3 block in Ordos Basin as an example, the Huang3 reservoir has been proved to have an average porosity of 8.45% and an average permeability of 0.55 mD. It is categorized as a low porosity to ultra-low permeability reservoir. Through laboratory experiments, the relationship between the permeability and caprock breakthrough pressure of a low permeability reservoir can be studied. The effects of carbon dioxide injection volume, recovery factor, injection method, and injection pressure on the storage factor/percentage are analyzed.

## 2. Experimental Method

### *2.1. Experimental Materials*

Overall, 10 cores were used in this study. The cores were taken from the Chang-8 layer in the Huang-3 area of Ordos Basin. The reservoir pressure and temperature were 15.6 MPa and 52.6 °C, respectively. The oil samples used in the experiment were also obtained from the Chang-8 layer. The crude oil density and viscosity are 0.84 g/cm$^3$ and 6.14 cp, respectively. The formation brine used is a $CaCl_2$ solution and the salinity is 26,000 mg/L. The core lengths range from 48.63 to 58.48 mm, the diameters range from 24.33 to 25.52 mm, the permeabilities ranges from 0.00243 mD to 0.98 mD, and the porosities range from 6.12 to 11.34% (Table 1).

**Table 1.** The petrophysical parameters of experimental cores.

<table>
<tr><th>No.</th><th>Well Name</th><th>Length (mm)</th><th>Diameter (mm)</th><th>Permeability (mD)</th><th>Porosity (%)</th><th colspan="2">Remarks</th></tr>
<tr><td>1</td><td>H29-100</td><td>50.03</td><td>25.26</td><td>0.00748</td><td>7.25</td><td colspan="2" rowspan="4">Caprock breakthrough pressure test</td></tr>
<tr><td>2</td><td>H29-104</td><td>49.35</td><td>25.24</td><td>0.00371</td><td>6.86</td></tr>
<tr><td>3</td><td>H29-105</td><td>50.12</td><td>25.25</td><td>0.00342</td><td>6.99</td></tr>
<tr><td>4</td><td>H29-106</td><td>50.06</td><td>25.26</td><td>0.00243</td><td>6.12</td></tr>
<tr><td>5</td><td>H53-89</td><td>50.01</td><td>25.43</td><td>0.51200</td><td>8.24</td><td rowspan="4">gas injection</td><td rowspan="6">For $CO_2$ flooding and storage experiment</td></tr>
<tr><td>6</td><td>H53-90</td><td>49.84</td><td>24.33</td><td>0.92300</td><td>11.34</td></tr>
<tr><td>7</td><td>H47-93</td><td>48.98</td><td>25.21</td><td>0.35200</td><td>7.96</td></tr>
<tr><td>8</td><td>H47-94</td><td>48.63</td><td>25.11</td><td>0.80400</td><td>10.89</td></tr>
<tr><td>9</td><td>H47-95</td><td>58.48</td><td>25.48</td><td>0.49000</td><td>8.01</td><td rowspan="2">Water injection alternate gas injection</td></tr>
<tr><td>10</td><td>H47-96</td><td>48.85</td><td>25.52</td><td>0.98000</td><td>11.26</td></tr>
</table>

### *2.2. Experimental Setup*

The instrument used in this experiment is the dynamic reservoir parameter test system, produced by Jiangsu Haian Petroleum Scientific Research Instrument Co., Ltd, Nantong, China (Figure 1). The pump, ISCO-260D, was produced in the United States, and the injection pressure ranges from 0 to 51.7 MPa. The injection flow rate is 0.01 to 10 mL/min; the porosity measurement range is 0–40%; the gas permeability range is 0.01–10,000 × $10^{-3}$ D.

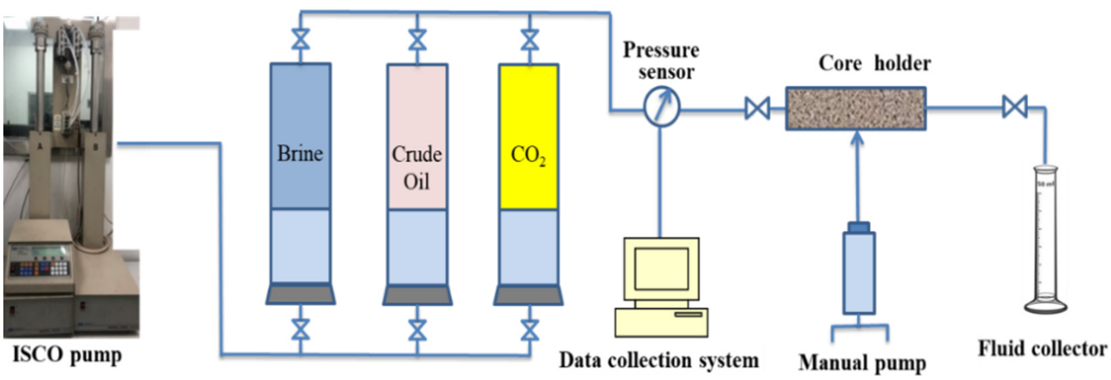


**Figure 1.** The flow chart of $CO_2$ flooding experiment.

### *2.3. Experimental Procedures*

#### 2.3.1. Caprock Breakthrough Pressure Test

We conducted the caprock breakthrough pressure test and adopted the following procedures:

(1) Measure the dimension and permeability of caprock cores (measured by pulse decay method);

(2) According to the measured permeability of 10 cores, 4 caprock cores with different permeability were selected;

(3) The core was evacuated in a vacuum saturation box. We saturated the selected core with formation water in an environment of 15 MPa, with a saturation time of 48 h, and the core quality was recorded before and after saturation. We calculated whether the saturation requirement was met, and in cases where the saturation requirement was not met, we re-saturated, increased the time required for saturation (such as 12 h), and increased the pressure (3 MPa);

(4) After the rock sample was saturated with water, it was placed in the core holder. The downstream end was immersed into the saturated sodium carbonate solution with a hose to observe whether $CO_2$ breaks through. The upstream end was injected with $CO_2$ at a constant pressure, the back pressure was set to 15 MPa (formation pressure), and the upstream injection pressure (18 MPa, 20 MPa, 22 MPa, 24 MPa, 26 MPa, 28 MPa, . . . , 50 MPa) was gradually increased. The pressure was stabilized for 2 h in each step. The flow rate was measured every 20 min;

(5) Four groups of caprock breakthrough pressure and $CO_2$ leakage rates were measured, and the corresponding upstream and downstream pressures were recorded. The upstream pressure at breakthrough was the breakthrough pressure and the pressure difference between upstream and downstream at breakthrough was the breakthrough differential pressure.

(6) We identified the relationship between permeability and breakthrough pressure and breakthrough pressure differences, fit the experimental results, and evaluated the sealing ability of the caprock.

#### 2.3.2. $CO_2$ Storage Factor Experiment

(1) The dry core was placed into the core holder and the formation brine was saturated using the displacement injection method, and then it was saturated with the formation oil to establish irreducible water saturation and oil saturation under formation conditions, after which the liquid rate at the outlet end was stabilized.

(2) Carbon dioxide was injected at a constant target pressure, the back pressure was set, we measured the injection volume, oil produced, and gas produced at different injection time steps, measured the proportion of $CO_2$, and finally obtained the $CO_2$ stored.

(3) Repeat steps (1) and (2), step (2) replace with formation water. The long core outlet back pressure was controlled at 15 MPa, and the inlet pump injection rate was controlled at 0.118 mL/min for displacement. When the water content reached 90%, we switched the gas injection container to $CO_2$ flooding until no oil was produced, recorded the injection volume and oil output at different injection times, collected gas and measured the proportion of $CO_2$, and finally obtain the $CO_2$ stored.

## 3. Experimental Results and Discussion

### *3.1. Caprock Breakthrough Pressure*

During the experiments, we noted that when the $CO_2$ injection pressure was lower than the breakthrough pressure of the rock sample, it was difficult for the gas to penetrate the core sample, and no gas was produced; when the pressure difference exceeds the breakthrough pressure, $CO_2$ overcame the capillary pressure and penetrated the core sample. After a long period, a large amount of $CO_2$ bubbles could be observed at downstream. The upstream pressure recorded at that moment was the breakthrough pressure and the upstream and downstream differential pressure was the breakthrough differential pressure. It has been known that the $CO_2$ trapped by the caprock is mainly caused by the capillary force [25]. With the increase of caprock permeability, the breakthrough pressure and differential pressure decrease rapidly, and the breakthrough pressure displays a good exponential relationship with permeability. The minimum breakthrough pressure of $CO_2$ in the caprock measured in the experiment is 22 Mpa (Figure 2), and the miscible pressure in the Huang 3 area is 16 MPa. Under the condition of maintaining miscible flooding, the possibility of $CO_2$ escaping through the caprock is small, but if the injection pressure is excessively increased (such as 30 MPa), there may be a risk of gas breakthrough the caprock near the injection well. However, considering that the average permeability of the caprock in the Huang-3 area is 0.00426 md, The breakthrough pressure gradient should be greater than 100 MPa/m (Figure 3). Therefore, the risk of $CO_2$ breakthrough through the caprock is relatively small. Therefore, the caprock in the Huang-3 area has good $CO_2$ geologic trapping properties.

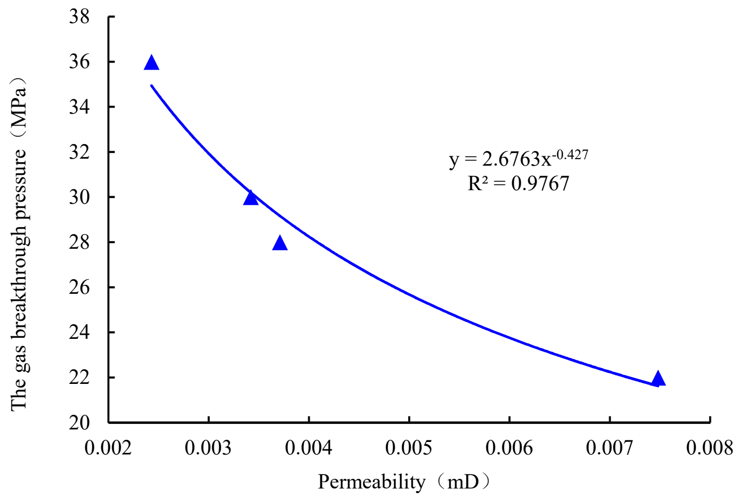


**Figure 2.** Relationship between permeability and breakthrough pressure.

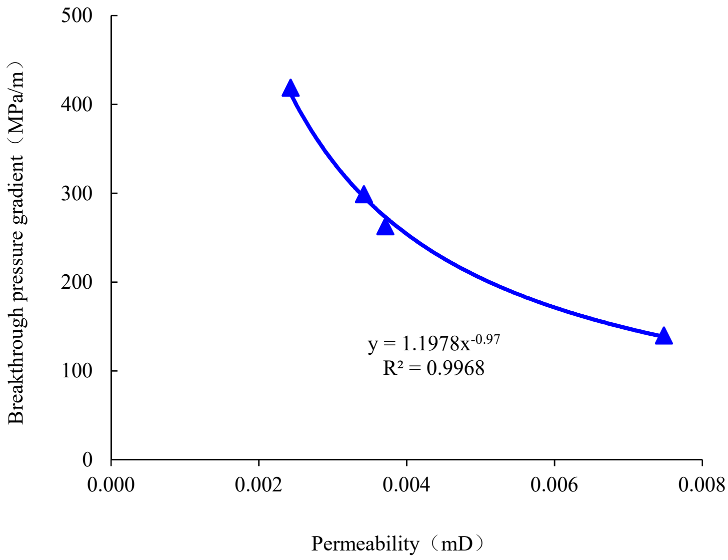


**Figure 3.** Relationship between permeability and breakthrough pressure gradient.

### *3.2. Effect of Injection Volume on the Storage Factor*

The carbon dioxide stored in the reservoir $M_{CO_2 stored}$ is mainly stored in oil $M_{CO_2 in\ oil}$ and formation brine $M_{CO_2 in\ aquifer}$. The carbon dioxide stored in the oil mainly includes: $CO_2$ stored in the remaining pore space left after oil displacement $M_{displace}$, $CO_2$ stored in the formation brine in the reservoir $M^{oil}_{dissolution\ in\ water}$, $CO_2$ stored in the remaining oil in the reservoir $M_{dissolution\ in\ oil}$, and $CO_2$ stored in the mineral $M^{oil}_{mineral}$.

$$M_{CO_2 stored} = M_{CO_2 in\ oil} + M_{CO_2 in\ aquifer} \quad (1)$$

$$M_{CO_2\text{in oil}} = M_{\text{displace}} + M^{\text{oil}}_{\text{dissolution in water}} + M_{\text{dissolution in oil}} + M^{\text{oil}}_{\text{mineral}} \quad (2)$$

The injected carbon dioxide $M_{CO_2\text{injection}}$ is the sum of the carbon dioxide produced with oil $M_{CO_2\text{produced}}$ and the carbon dioxide stayed in the formation $M_{CO_2\text{stored}}$. The storage factor of carbon dioxide in the reservoir $\eta$ is:

$$\eta = \frac{M_{CO_2\text{stored}}}{M_{CO_2\text{stored}} + M_{CO_2\text{produced}}} = \frac{M_{CO_2\text{stored}}}{M_{CO_2\text{injection}}} \quad (3)$$

$CO_2$ is continuously injected into the reservoir. The more $CO_2$ is injected, the lower the storage percentage. Especially after gas channeling, a large amount of injected $CO_2$ is recovered with crude oil. For high permeability cores, when the injection gas volume is less than 0.7 pore volume (PV), with the increase of gas injection rate, the produced gas-oil ratio is 0, and the carbon dioxide storage percentage can reach 100%. All the injected carbon dioxide is either dissolved in crude oil or stored in the pore space. When the gas injection rate is 0.7–1.5 PV, with the increase of gas injection rate, the gas–oil ratio increases slowly, and the storage percentage decreases. For low permeability cores, when the gas injection volume is greater than 1.04 PV, the gas–oil ratio increases gradually. When the gas injection volume is greater than 1.5 PV, the gas–oil ratio increases rapidly, and the carbon dioxide storage percentage decreases. Combined with the storage percentage, it can be found that, in the reservoirs with low permeability, when the injection gas volume is 0.7~1.1 PV, the carbon dioxide storage effect is better (Figure 4). Since the core permeability is not vastly different, it is impossible to further compare the impact of permeability on the storage effect. With the increase of gas injection, crude oil recovery increases. When the gas injection is greater than 0.7 PV, the increase of crude oil recovery decreases significantly. At the same gas injection rate, the recovery of the high permeability core is greater than that of the low permeability core (Figure 5).

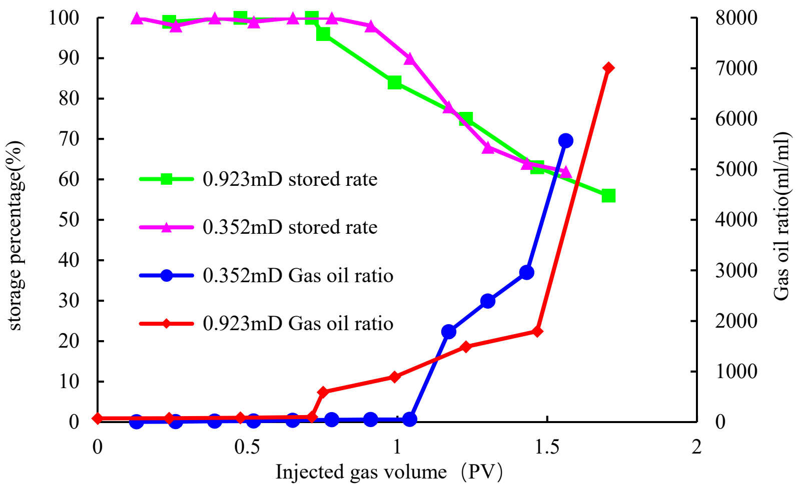


**Figure 4.** Relationship between injection volume and storage percentage at different rock permeability.

### 3.3. *Influence of Oil Recovery Factor on Storage Percentage*

At the same storage percentage, the recovery factor of crude oil from a high permeability core is higher. The storage percentage decreases with the increase of the recovery factor. When the 0.352 mD core experiences gas channeling, the storage percentage is about 68%. When 0.923 mD rock core experiences gas channeling, the storage percentage is lower, at around 63%. Therefore, a low permeability reservoir rock is more capable of storing $CO_2$ (Figure 6). This is the case after a threshold recovery factor which is between 45% to 50% for the studied cores. Below that threshold, the storage percentage is not sensitive to the recovery factor or the permeability of rock.

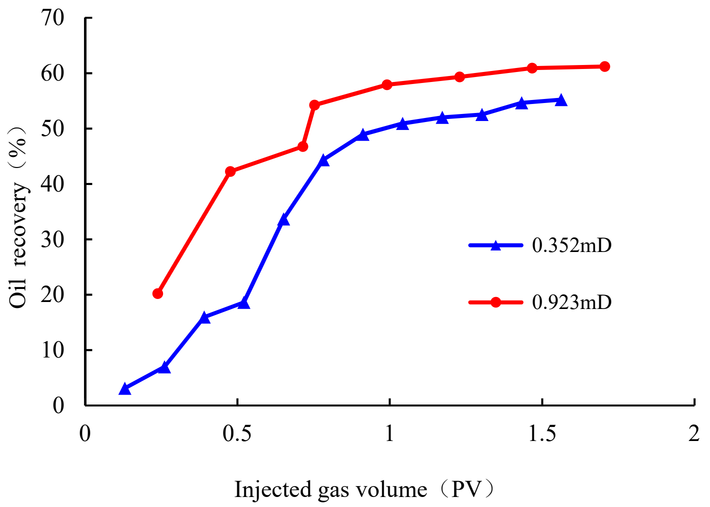


**Figure 5.** Relationship between $CO_2$ injection and recovery at different core permeability.

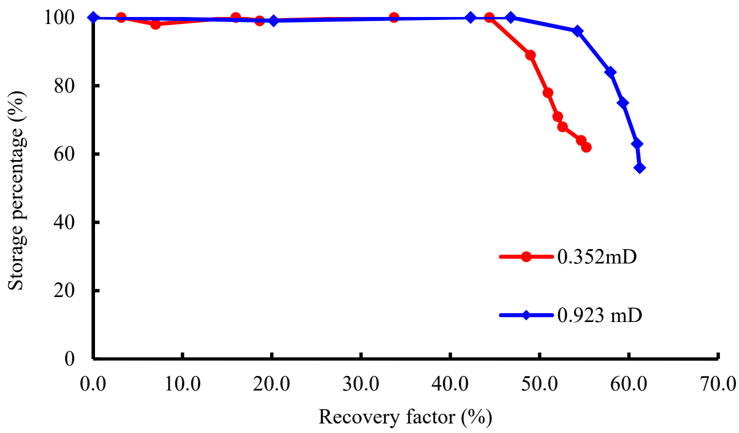


**Figure 6.** Relationship between recovery degree and storage percentage.

### *3.4. Effect of Injection Method on the Storage Percentage*

In the process of continuous gas injection, the gas injected with about 0.7 PV breaks through, and the gas storage percentage decreases rapidly. When the injected gas is about 1.2 PV, the retention rate decreases slightly; the injection is altered from water injection to gas injection when the water cut achieves 90%, and the initial change of storage percentage is small. However, when the gas injection is 0.9 PV, gas is produced, gas channeling is rapid, and the storage percentage decreases faster than during continuous gas injection (Figure 7). The analysis suggests that the water film in some core pores reduces the pore space after the initial water injection following the switch to gas flooding, so that the storage percentage decreases faster after gas channeling than continuous gas injection. It shows that continuous gas injection is more conducive to the geological sequestration of carbon dioxide.

### *3.5. Effect of Injection Pressure on Storage Percentage*

The higher the injection pressure, the more carbon dioxide will be dissolved into the crude oil. The better the miscibility between carbon dioxide and crude oil, the higher the recovery factor of crude oil and the greater the storage factor. When the injection volume is greater than 0.95 PV, the carbon dioxide storage decreases after the gas breakthrough. Under the same injection PV, the burial rate of the carbon dioxide miscible phase is greater than that of the immiscible phase (Figure 8), and greater injection pressures result in enhanced geological sequestration under the miscible injection scenario. At the same gas–oil ratio, the recovery factor of miscible crude oil is greater than that of immiscible crude oil. The lower the pressure, the lower the miscibility degree of carbon dioxide and crude oil. The more serious the fingering phenomenon is in the process of gas flooding, the easier it is to produce injected gas. The immiscible gas–oil ratio is greater than the miscible gas–oil ratio (Figure 9), thus affecting the storage efficiency of carbon dioxide.

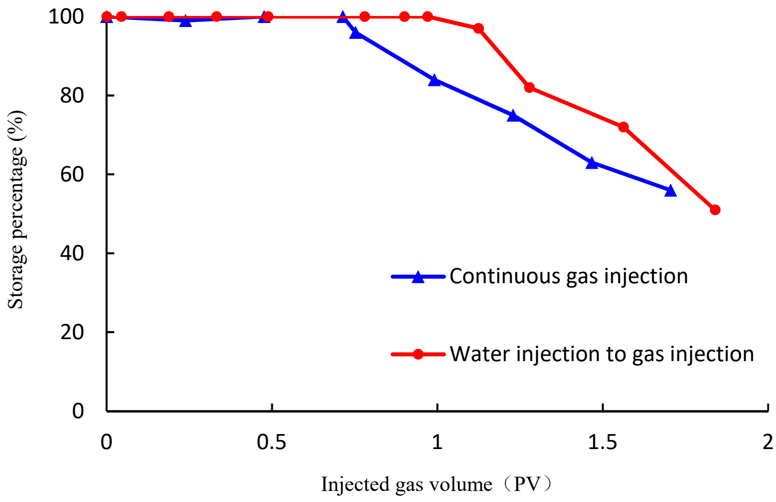


**Figure 7.** Relationship between injection mode and storage factor.

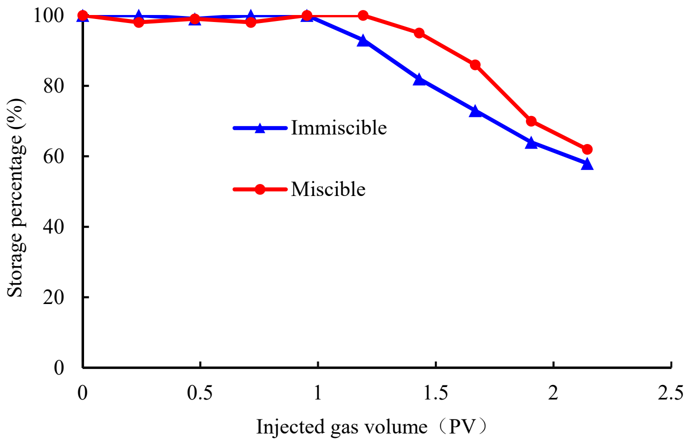


**Figure 8.** Relationship between injection volume and storage percentage.

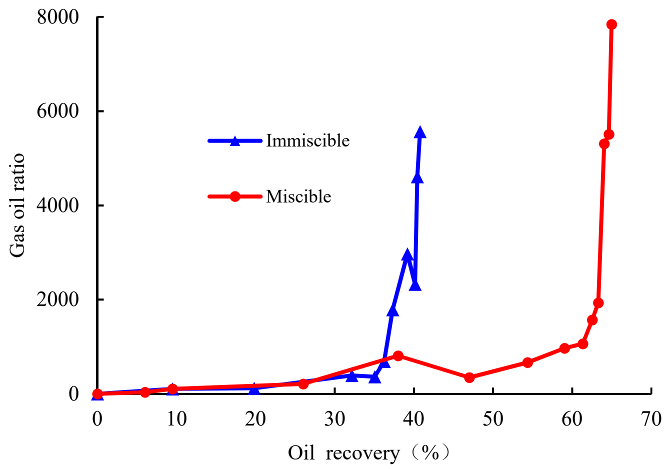


**Figure 9.** Relationship between gas-oil ratio and recovery degree.

## 4. Conclusions

(1) The sealing of $CO_2$ by caprock is mainly a result of capillary force. With the increase of caprock permeability, the breakthrough pressure and differential pressure decrease rapidly, and a good exponential relationship between caprock breakthrough pressure and permeability can be achieved;

(2) The minimum breakthrough pressure of $CO_2$ flooding in saturated formation water caprock is 22 MPa, the breakthrough pressure gradient is greater than 100 MPa/m, and the miscible pressure in the work area is 16 MPa. Under the condition of maintaining miscible flooding, the possibility of $CO_2$ escaping through the caprock is small. Therefore, the Huang 3 area is suitable for $CO_2$ geological sequestration, and the risk of $CO_2$ breaking through the caprock is small;

(3) For high permeability cores, when the gas injection rate is less than 0.7 PV, with the increase of injected volume, the produced gas–oil ratio is 0, and the carbon dioxide storage percentage can reach 100%. All the injected carbon dioxide is dissolved in crude oil and stored in the formation. For low permeability cores, when the gas injection is greater than 1.04 PV, the gas-oil ratio gradually increases. Combined with the storage percentage, it can be found that in the reservoirs with low permeability, when the injection gas volume is 0.7~1.1 PV, the carbon dioxide storage effect is better. With the increase of the gas injection, the oil recovery increases. At the same gas injection volume, the recovery of the high-permeability core is greater than that of the low-permeability core.

(4) At the same storage percentage, the recovery factor of crude oil is higher in a core with higher permeability. The storage percentage decreases with an increase in the recovery factor, and low-permeability reservoirs are more prone to store $CO_2$. Compared with water-gas-altering injection, continuous injection is more conducive to the geological storage of carbon dioxide.

(5) Under the same injection PV, the storage percentage of the carbon dioxide miscible phase is greater than that of the immiscible phase, indicating that the greater the pressure, the more conducive it is to the geological storage of carbon dioxide. At the same gas–oil ratio, the recovery factor of miscible crude oil is greater than that of immiscible crude oil.

**Author Contributions:** Conceptualization, methodology, validation, formal analysis, project administration and funding acquisition P.Y.; software, data curation, visualization and writing—original draft preparation, R.Z.; investigation, F.L.; resources, G.Y.; writing—review and editing, J.J.S.; supervision, P.Y. All authors have read and agreed to the published version of the manuscript.

**Funding:** This research was funded by the China Postdoctoral Science Foundation [No. M2019650965], Major R & D Plan of Sichuan Province [No. 2020YFQ0034], the National Natural Science Fund Projects [Grant No. 51804253] and Shaanxi Key Laboratory of Continental Shale Gas Accumulation and Exploitation [YJSYZX18SKF0001].

**Acknowledgments:** Thanks to Liu Dongchen for his help in the revision process.

**Conflicts of Interest:** The authors declare no conflict of interest.

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