INTRODUCTION

Preliminary development of unconventional gas resources in the United States can be traced back to the 1970s, and development of unconventional gas resources is expected to continue long into the future as industry strives to optimize recovery of worldwide energy resources. The total volume of global unconventional gas resources, which includes tight gas, shale gas, and coalbed methane (CBM), is over 8 times the volume of conventional gas resources.\(^1,2\) and the recoverable volume of these resources is estimated to be \(920 \times 10^{12} \text{ m}^3\).\(^3,3\) The economic potential of efficiently developing these unconventional gas resources is clearly very significant.

Tight gas, one of these unconventional resources, has attracted a great deal of industry attention as it is one of the most realistic alternatives to conventional supply. Global tight gas reserves are roughly estimated to be \(95.16 \times 10^{12} \text{ m}^3\) with recoverable resources of \(15.89 \times 10^{12} \text{ m}^3\).\(^4\) Rock formations...
in tight gas reservoirs generally have very small pore throats, which create extremely high capillary forces. Water invasion induced by capillary force imbibition creates high water saturation, which in turn results in WPT damage.\(^5\-10\) During water invasion, water film continuously amasses, gradually trapping the gas and eventually cutting off continuous gas flow. Even when water is displaced by formation pressure during the drainage process, water saturation does not revert back to its initial values due to the extremely low matrix permeability and high capillary pressure. The increase of water saturation from initial water saturation (\(S_{wi}\)) to final irreducible water saturation (\(S_{wirr}\)) is the primary cause of WPT damage.\(^5\) Tight gas reservoirs have been shown to have a strong water-wet nature and, as such, have the potential of significant capillary energy due to their ultralow initial water saturation phenomena.\(^11\-12\) This creates an extremely powerful capillary suction tendency, which brings water into the matrix and causes WPT, the most common and severe challenge that operations such as well drilling, completion, cementing, fracturing, and acidizing encounter in tight gas reservoir environments.\(^13\-21\)

Research into WPT damage can play a significant role in guiding effective fluid performance design during the exploration and development of a tight gas reservoir. One such study involved spontaneous capillary water imbibition experiments that were carried out to mimic the water invasion process.\(^22\-24\) A limiting back pressure was applied to eliminate the gas slippage effect during the measurement process to ensure the precise testing of gas permeability in tight rocks.\(^25\) The success of this experimental study of spontaneous capillary water imbibition and the advances of gas permeability measurements has resulted in WPT damage evaluation becoming a topic of considerable interest in tight gas reservoir research. Other work on WPT has focused on examining the effects of rock permeability,\(^17\) wettability,\(^26\-27\) interfacial tension,\(^3\) capillary force,\(^14\-16\) water saturation,\(^5\,28\,29\) invasion depth,\(^14\-16\) formation temperature, and formation pressure,\(^5\,13\,30\) all with the aim of reducing or eliminating the damage more effectively.

Wettability, formation temperature and pressure, working fluid property, and interfacial tension are normally available for a reservoir under specific well operations. Given that the physical parameters of the rock and the variations of water saturation are considered to be the main controlling factors affecting WPT, this paper will investigate the impact of rock porosity, gas permeability, and average pore throat radius on both water drainage and gas permeability recovery from WPT damage. The relationship between physical parameters of the rock and the associated WPT phenomena will be examined based on water imbibition and drainage experiments, and an empirical formula will be applied to calculate the water film in order to confirm the results. The findings will facilitate a deeper understanding into the dominant petrophysical factors in WPT.

## MATERIALS AND METHODS

### 2.1 Core samples

Core samples used in this study were from the Daniudi tight gas reservoirs of Ordos Basin in midwestern China. The lithology of the core samples was mainly grayish lithic quartz sandstone with an average quartz content of 74.8%, an average cuttings

| Sample ID | Length \(L\), mm | Diameter \(D\), mm | Porosity \(\phi\), % | Permeability \(K\), mD | Mass \(M\), g | Pore volume \(V\), cm\(^3\) |
|-----------|-----------------|-----------------|----------------|----------------|------------|----------------|
| 1         | 49.83           | 25.06           | 5.90           | 0.275          | 62.746     | 1.484         |
| 2         | 45.90           | 25.15           | 8.10           | 0.268          | 56.372     | 1.857         |
| 3         | 50.92           | 25.06           | 6.40           | 0.400          | 62.943     | 1.598         |
| 4         | 46.97           | 25.67           | 3.62           | 0.129          | 63.051     | 0.820         |
| 5         | 50.65           | 24.86           | 3.00           | 0.244          | 63.653     | 0.744         |
| 6         | 55.94           | 25.62           | 3.43           | 0.122          | 74.731     | 0.990         |
| 7         | 48.84           | 25.17           | 11.60          | 0.637          | 57.911     | 3.301         |
| 8         | 46.28           | 25.43           | 7.83           | 0.282          | 57.14      | 1.840         |
| 9         | 50.05           | 24.82           | 8.90           | 0.383          | 58.534     | 2.160         |
| 10        | 52.24           | 25.08           | 9.90           | 0.375          | 65.870     | 2.542         |
| 11        | 53.63           | 25.45           | 8.68           | 0.548          | 66.099     | 2.370         |
| 12        | 52.65           | 24.90           | 10.40          | 0.635          | 59.944     | 2.919         |
| 13        | 53.25           | 25.24           | 9.90           | 0.679          | 63.801     | 2.639         |
| 14        | 52.20           | 24.85           | 9.90           | 0.728          | 60.652     | 2.510         |
| 15        | 56.51           | 25.64           | 9.96           | 0.680          | 69.309     | 2.910         |
content of 10.5%, and an average clay mineral content of 14.7%. Porosity and permeability analysis were performed for all 15 samples under a confining pressure of 3 MPa and a testing pressure of 0.6 MPa. Porosity was in the 3%-12% range and permeability was between 0.1 and 1.0 mD. Porosity and permeability data for the selected core samples are listed in Table 1, and a porosity vs permeability chart is shown in Figure 1.

Other physical features of these core samples, including the tight matrix and micro/nanopores which create high water capillary imbibition forces and a strong potential of WPT damage, are shown in the following Scanning Electron Microscopy (SEM) images (seen in Figure 2).

2.2 | Experimental method

The experimental setup used in this study, as illustrated in Figure 3, was self-designed and assembled specifically to conduct WPT damage tests at low gas flow rates in tight rocks. As shown, the setup included air bottles, a core holder, a displacement pump, a back pressure regulator, and a data capture system. The displacement pump, with a constant flow rate of 0.001 mL/min to ensure data reliability, was used to inject water through the core sample at a constant displacement pressure. The computer connected to a pressure transducer (0.5% precision over a 60 MPa...
range) was used to record pressure readings at both the inlet and outlet of the core. The gas flow-meter was used to measure the gas stream flow rate, which was desiccated using a drying vessel. Dried nitrogen (purity 99.99%) was used to measure gas permeability, and a mass fraction of 3% KCl solution was used to perform water imbibition experiments.

The laboratory process of evaluating WPT damage included three stages, which showed the variations of gas permeability and water saturation over test time. A more detailed discussion of these stages can be found in a previous work. As illustrated in Figure 4, the experimental procedures used to simulate water imbibition, water drainage, and gas permeability measurements during WPT for each core are as follows:

1. The core sample was treated to establish an initial connate water saturation ($S_{wi}$) of 20% to represent the reservoir’s initial ultralow water saturation by using a capillary imbibition method (CIM). The core sample was placed on the water soaked paper and then rolled back and forth so that the water would penetrate the sample matrix through capillary force. $S_{wi}$ was attained once the water-invaded core mass reached the expected value according to the core dry mass, pore volume, and predefined water saturation. The core sample was then placed in sealed container and stored in a cool environment for 48 hours to ensure homogenized water saturation.

2. Mass of the core sample was measured before the permeability test, and then, the core sample was placed into the core holder. The gas stream flow rate was measured under a 7 MPa confining pressure, testing pressure gradient of 0.3 MPa/cm, and a back pressure of 1 MPa (the pressure limit to eliminate gas slippage effect during measurement). Gas permeability was determined using Darcy’s law before commencement of water phase trapping damage tests.

3. The pump was used to inject water at 0.05 MPa pressure to fill the dead volume in the tubing before the imbibition experiment was initiated. When the water contacted the end surface of the core sample, the injection rate underwent a sudden drop and the pump was switched to manual mode with no pumping pressure to initiate water invasion into the core through capillary force. This method simulated spontaneous water capillary imbibition and was generally carried out for around 16 hours.

4. Following water invasion, the core was removed and its mass was measured before being returned to the core holder. Pressure, in a process similar to that described in procedure 2, was resumed to initiate water drainage process. The recovered gas stream flow rate was measured, and permeability was determined.

5. Once the return gas permeability was measured to be steady, the core sample was again removed and mass was measured.

6. At this stage, the experiment concluded and data recorded by the computer were analyzed.

3 | RESULTS

3.1 | Water imbibition and drainage behaviors

The imbibition processes of the 15 tight core samples were analyzed and as shown in Figure 5, an increment of water mass in the range of 0.108-1.256 g was reached after 16 hours of capillary imbibition (Figure 5A). As the data shown in Figure 5B suggests, the strongest imbibition stage
occurred in the first four hours. After that, a weaker stage followed before stability was gradually reached. The results also suggest that samples with relatively higher permeability and porosity experienced faster imbibition with more water. The invaded water can be displaced by reservoir production pressure in the process known as water drainage. During water drainage, water saturation declines and gas permeability recovers. Figure 6 shows gas permeability damage curves during the water drainage and illustrates that the most significant water drainage and gas permeability recovery stage occurred in the first hour. However, even following drainage core water saturation did not revert to its initial water saturation value and damage to gas permeability had been induced by WPT. The data also clearly show that water drainage in samples with relative high permeability is greater than those with lower permeability at the same displacement pressure gradient.

3.2 Damage to gas permeability caused by WPT

Permeability damage induced by WPT included temporary and permanent damage depending on the scenario. Temporary damage was caused by the temporary increase of water saturation during the water invasion period while permanent damage was caused by the increase of water saturation even after drainage. Clearly, permanent damage occurred when the irreducible water saturation was higher than the initial water saturation after water was purged from the core and the higher the difference, the greater the severity of WPT damage. As shown in Table 2, an average water saturation increased from 19.41% (initial water saturation, $S_{wi}$) to 47.66% after imbibition and declined to 38.72% (irreducible water saturation, $S_{wirr}$) after drainage. Water drainage rates ranged from 9.26% to 69.75%, with an average drainage rate of 31.94%. After drainage, there was an average increase of 19.31% to the water saturation, which was the reason of decline in gas permeability. The gas permeability damage rate of the core samples ranged from 36.03% to 78.10%, with an average damage value of 59.31%. These results show severe damage to gas permeability in all 15 tight core samples and clearly demonstrate the occurrence of WPT.

The relationship between predamage ($K_1$) and postdamage ($K_2$) permeability has a correlation index of 0.95 as shown below in Figure 7. It can be concluded that core samples with a lower rock permeability suffered more severe WPT damage in tight gas reservoirs.
The exponential relationship observed between the degree of water drainage and the gas permeability damage rate after water drainage is illustrated in Figure 8. The degree of water drainage influenced residual water saturation in the pore space, which in turn affected the gas permeability reduction level. During the drainage process, water saturation was reduced and gas was able to partially reoccupy the pore space that had previously been filled with water. As the results show, gas permeability damage was due to an increase in water saturation from WPT in the pore space and a generally high degree of water drainage corresponded to lower gas permeability damage rate.

4 | DISCUSSION

4.1 | Effect of rock physical parameter on WPT

In this section, the impact of rock porosity, permeability, and average pore throat radius on WPT damage will be discussed.

4.1.1 | Rock porosity

Porosity is a basic physical parameter of formation rock and offers more reliable information with respect to pore volume than pore geometry. Once WPT damage has occurred and some pore space is occupied by water, less pore space is left to act as a flow channel. Since not all rock pore volume allows gas flow after water invasion, rock porosity does have some affect the WPT. However, as the results in Figure 9 show the relationship between rock porosity, the degree of water drainage and gas permeability damage is not particularly significant and actually shows that porosity generally has a weak influence on WPT damage and is not a vital petrophysical factor affecting WPT damage.

4.1.2 | Gas permeability

Figures 10 and 11 investigated the influence of rock gas permeability on both water drainage rate and permeability

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**TABLE 2** Experimental results of WPT damage for the 15 tight sandstone core samples

| Sample ID | $S_i$, % | $S_w$, % | $S_{irr}$, % | Drainage rate, % | $K_1$, mD | $K_2$, mD | $\Delta K$, % |
|-----------|----------|----------|-------------|-----------------|------------|------------|-----------|
| 1         | 21.97    | 63.27    | 59.33       | 9.55            | 0.0326     | 0.0071     | 78.10     |
| 2         | 18.42    | 63.81    | 53.86       | 21.93           | 0.0327     | 0.0099     | 69.79     |
| 3         | 18.90    | 47.81    | 43.04       | 16.49           | 0.0744     | 0.0210     | 71.72     |
| 4         | 21.34    | 34.51    | 33.29       | 9.26            | 0.0161     | 0.0038     | 76.65     |
| 5         | 23.01    | 67.07    | 62.85       | 9.58            | 0.0120     | 0.0046     | 62.00     |
| 6         | 16.77    | 27.98    | 26.43       | 13.81           | 0.0139     | 0.0050     | 63.86     |
| 7         | 19.33    | 55.29    | 43.37       | 33.14           | 0.0956     | 0.0369     | 61.36     |
| 8         | 21.30    | 40.87    | 36.19       | 23.89           | 0.0367     | 0.0153     | 58.41     |
| 9         | 20.09    | 51.85    | 43.98       | 24.80           | 0.0557     | 0.0176     | 68.46     |
| 10        | 18.02    | 39.81    | 34.76       | 23.16           | 0.0407     | 0.0145     | 64.45     |
| 11        | 18.48    | 40.55    | 31.39       | 41.49           | 0.1007     | 0.0435     | 56.78     |
| 12        | 18.60    | 41.35    | 28.12       | 58.13           | 0.1365     | 0.0801     | 41.33     |
| 13        | 19.14    | 47.14    | 29.86       | 61.71           | 0.1160     | 0.0726     | 37.38     |
| 14        | 18.49    | 68.53    | 33.63       | 69.75           | 0.1863     | 0.1192     | 36.03     |
| 15        | 17.22    | 26.60    | 20.75       | 62.38           | 0.1180     | 0.0670     | 43.25     |

Note: $S_i$ is the initial water saturation before the imbibition. $S_w$ is the water saturation after the imbibition. $S_{irr}$ is the irreducible water saturation after the drainage. Drainage rate is calculated by the formula of $(S_w - S_{irr})/(S_w - S_i) \times 100\%$. $K_1$ is the core permeability before damage, and $K_2$ is the core permeability after the damage. $\Delta K$ is the damage rate of core permeability, which is calculated by the formula of $(K_1 - K_2)/K_1 \times 100\%$.

**FIGURE 7** Relationship between predamage permeability ($K_1$) and postdamage ($K_2$) permeability of the WPT for 15 tight gas reservoirs core samples

R² = 0.95
damage rate. The results show that the relationship became much more pronounced when gas permeability after WPT damage was used as an analysis index instead of the gas permeability before damage. It points out that gas permeability after damage offers more direct evidence that an increase in water saturation during the process of WPT reduces gas flow ability. It can be also concluded that reservoir with low rock permeability has a lower water removal capacity and therefore suffers more severe WPT damage. The results firmly lead the conclusion that WPT damage has a relevant relationship with rock permeability than rock porosity.

4.1.3 | The average pore throat radius

Average pore throat radius (i.e., the effective pore size for fluid flow in porous media) is generally used to determine the average capillary force and rock permeability, which influences water and gas flow behaviors. According to the Kozeny-Carman formula,\(^{33,34}\) the relationship between pore throat and permeability can be derived and described as follow\(^{35}\):

\[
r = \sqrt{\frac{8K}{\varphi}}
\]  

(1)
where $K$ (D) is the rock permeability, $\phi$ (fraction) is the rock porosity, and $r$ ($\mu$m) is the average pore throat radius.

Assuming that rock porosity does not change during experiment, the average pore throat radius of each sample before and after WPT damage can be calculated by using the following formulas:

$$r_1 = \sqrt{\frac{8K_1}{\phi}}, \quad r_2 = \sqrt{\frac{8K_2}{\phi}}$$

where $K_1$ and $K_2$ are gas permeability before and after damage and $r_1$ and $r_2$ are core's average pore throat radius before and after damage. Calculation results presented in Table 3 show that the average pore throat of the core samples ranged from 0.057 $\mu$m to 0.123 $\mu$m before WPT damage, and 0.029 $\mu$m to 0.098 $\mu$m after WPT damage, a reduction ranging from 20.02% to 53.20%. It strongly suggests that an increase in water saturation due to WPT damage reduces the effective pore size allowing gas flow.

Figures 12 and 13 show that the average pore throat radius after WPT damage has a close relationship to the degree of both water drainage rate and gas permeability damage rate, with the fitting curve showing a higher coefficient ($R^2$) for the average pore throat radius after WPT damage. It can be inferred that core samples with smaller average pore throat radius have a lower degree of water drainage and suffer more severe WPT damage to gas permeability.

Figure 14 shows a particularly convincing relationship between pore throat radius reduction and gas permeability damage rate due to the WPT with $R^2$ equaling 0.9980. The variation of permeability damage was much greater than the degree in pore throat radius reduction when some decrease in pore throat radius existed indicating that permeability damage is more sensitive to reduction in pore size. This clearly demonstrates that WPT reduced or occupied the gas flow channel, which in turn caused a decline in gas permeability.

### Table 3

Permeabilities damage and average pore throat radius changes of 15 cores samples after WPT

| Sample ID | Porosity, % | $K_1$, mD | $K_2$, mD | Drainage rate, % | $\Delta K$, % | $r_1$, nm | $r_2$, nm | $\Delta r$, % |
|-----------|-------------|-----------|-----------|-----------------|---------------|-----------|-----------|--------------|
| 1         | 5.90        | 0.0326    | 0.0071    | 9.55            | 78.10         | 66.49     | 31.11     | 53.20        |
| 2         | 8.10        | 0.0327    | 0.0099    | 21.93           | 69.79         | 56.83     | 31.24     | 45.03        |
| 3         | 6.40        | 0.0744    | 0.0210    | 16.49           | 71.72         | 96.44     | 51.28     | 46.82        |
| 4         | 3.62        | 0.0161    | 0.0038    | 9.26            | 76.65         | 59.65     | 28.83     | 51.67        |
| 5         | 3.00        | 0.0120    | 0.0046    | 9.58            | 62.00         | 56.57     | 34.87     | 38.36        |
| 6         | 3.43        | 0.0139    | 0.0050    | 13.81           | 63.86         | 56.98     | 34.25     | 39.89        |
| 7         | 11.60       | 0.0956    | 0.0369    | 33.14           | 61.36         | 81.20     | 50.47     | 37.84        |
| 8         | 7.83        | 0.0367    | 0.0153    | 23.89           | 58.41         | 61.23     | 39.49     | 35.51        |
| 9         | 8.90        | 0.0557    | 0.0176    | 24.80           | 68.46         | 70.78     | 39.75     | 43.84        |
| 10        | 9.90        | 0.0407    | 0.0145    | 23.16           | 64.45         | 57.35     | 34.19     | 40.37        |
| 11        | 8.68        | 0.1007    | 0.0435    | 41.49           | 56.78         | 96.34     | 63.33     | 34.26        |
| 12        | 10.40       | 0.1365    | 0.0801    | 58.13           | 41.33         | 102.47    | 78.49     | 23.41        |
| 13        | 9.90        | 0.1160    | 0.0726    | 61.71           | 37.38         | 96.82     | 76.62     | 20.87        |
| 14        | 9.90        | 0.1863    | 0.1192    | 69.75           | 36.03         | 122.70    | 98.13     | 20.02        |
| 15        | 9.96        | 0.1180    | 0.0670    | 62.38           | 43.25         | 97.35     | 73.34     | 24.66        |

Note: $K_1$ and $K_2$ are core permeability before and after the damage. $\Delta k$ is the core permeability damage rate. $r_1$ and $r_2$ are the core average pore throat radius before and after the damage. $\Delta r$ is the core average pore throat radius reduction rate, which is calculated by the formula of $(r_1 - r_2)/r_1 \times 100\%$. 

**Figure 11** Relationship between the gas permeability (before/after) damage and gas permeability damage rate for 15 tight gas reservoirs core samples
4.2 Changing of effective gas flow channel during WPT

The investigation into the relationship between rock porosity, permeability, and average pore throat radius with water drainage and gas permeability reduction suggests that the most relevant factor controlling WPT damage is average pore throat radius. To further investigate the sensitivity of pore size to WPT, the study of the impact of water film on the reduction of effective gas flow channel was performed.

The gas-water distribution and trapped gas formation processes in porous media were investigated by using a visualization model, which showed quite remarkably that water invaded along the pore wall to form a water film at the beginning of water invasion as shown in Figure 15A. As water saturation increased (Figure 15B), trapped gas bubbles and columns appeared in some corners, branches, and narrow sections. With high water saturation established, most of the pore throats filled with water by the accumulation and thickening of water film, which in turn further impacted gas flow as shown in Figure 15C. The remaining images (Figure 15D-F) show the water drainage process and illustrate the phenomenon of water film at irreducible water saturation after drainage. The model also indicates that gas flows at the center of pore throats while water is adsorbed on the pore wall when a gas-water system flows through the hydrophilic porous media.

The visualization experiments demonstrated that there are two types of fluid states when gas-water fluid flows through the pores (capillaries). One is the water film layer adsorbed on the pore wall and the other is the free gas layer, which freely flows through the center of the pore. In most conventional rocks, the thickness of the water film has a minimal effect on the radius of the flow channel so the influence of the water film on gas flow can generally be overlooked (Figure 16A). However, as pore throats in tight rocks are extremely small, with most of them being less than 0.1 μm, the thickness of water film can have a significant influence on gas flow in tight rocks (Figure 16B).

In order to further quantify the relationship between water film and reduced gas flow in rock channels, the average thickness of the water film covering pore walls in the core samples following WPT damage was determined by using an empirical formula below:

\[
h = \frac{0.7142\rho S_{\text{wirr}}}{A\rho}
\]  

(3)
where \( h \) (nm) is the thickness of water film, \( \phi \) (%) is the rock porosity, \( S_{\text{irr}} \) (%) is the core irreducible water saturation after drainage, \( A \) (m\(^2\)/g) is the rock-specific surface area, and \( \rho \) (g/cm\(^3\)) is the rock density.

Based on the experimental data obtained in this study, the thickness of the water film and the reduced pore size can be calculated using formulas (2) and (3). Calculation results are listed in Table 4 and show that the calculated thickness of water film was 21.22-38.18 nm, with an average of 27.37 nm. The reduction of the effective pore size after water drainage was 20.20-45.15 nm with an average of 27.59 nm. The average values of calculated thickness of water film and pore throat reduction do correspond, which shows that effective gas flow channels occupied by water film are the most common cause of gas permeability damage from WPT. Considering that the calculated thickness of the water film of the core samples used in this study were in the range of 22.12-38.18 nm, pore channels with sizes below these values will be totally filled with water, trapping gas and leaving only those pore throats not totally blocked with water film to be effective gas flow.
It can be safely inferred that the existence of water film in tight rocks with smaller pore throats can reduce the size of gas effective flow channels mostly, resulting in a more severe WPT damage. Figure 17 shows that the calculated thickness of the water film and the reduction in pore size are at the same nanometer level. Using Formula (3), the findings further illustrate that these factors contribute to the close relationship between WPT damage and the reduction of effective gas flow pore sizes. In general, it proves that the changes of effective gas flow pore size and the influence of water film on gas permeability reduction provide a reasonable understanding of how WPT damage occurs.

High irreducible water saturation can generally be associated with the smaller pore throat radius after drainage. The size of larger pore channels is reduced due to the water film while some smaller pore channels are totally occupied by water. The effect of water film on effective pore throat channel size can be described using the formula $r_e = r - h$, where $r_e$ is the gas flow pore throat channel and $h$ is water film thickness. Thus, pore space for gas flow decreases correspondingly, which in turn results in a decline in gas permeability. This leads to the conclusion that pore throat size in a core sample is a dominant petrophysical parameter controlling the sensitivity of WPT. According to Formula (1) and considering the effect of water film on the effective pore channel size for gas flow, the actual permeability of core sample after WPT occurred can be calculated by Formula (4) as follow:

$$K = \frac{\varphi (r-h)^2}{8}$$  \hspace{1cm} (4)

Based on the Formula (4), it can be inferred that the invaded water can reduce (by adsorbed water film) or even occupy (by capillary-dominated film) the effective gas flow channel, which in turn cause a damage to gas permeability when WPT occurs (Figure 18). Meanwhile, tight rocks with a lower matrix permeability that correspond to tiny pore throats will be greatly affected by water film and suffer more severe WPT damage.

| Sample ID | $A_{\text{m}^2/g}$ | $\rho_{\text{g/cm}^3}$ | $\varphi$ | $S_{\text{swirr}}$ | $h_{\text{nm}}$ | $r_1_{\text{nm}}$ | $r_2_{\text{nm}}$ | $r_D_{\text{nm}}$ |
|-----------|---------------------|----------------------|--------|-----------------|--------|---------|---------|---------|
| 1         | 2.41                | 2.72                 | 5.90   | 59.33           | 38.14  | 66.49   | 31.11   | 35.37   |
| 2         | 3.68                | 2.69                 | 8.10   | 53.86           | 31.48  | 56.83   | 31.24   | 25.59   |
| 3         | 2.26                | 2.68                 | 6.40   | 43.04           | 32.48  | 96.44   | 51.28   | 45.15   |
| 4         | 1.07                | 2.68                 | 3.62   | 33.29           | 30.01  | 59.65   | 28.83   | 30.82   |
| 5         | 2.13                | 2.67                 | 3.00   | 62.85           | 23.68  | 56.57   | 34.87   | 21.70   |
| 6         | 1.01                | 2.68                 | 3.43   | 26.43           | 23.92  | 56.98   | 34.25   | 22.73   |
| 7         | 4.07                | 2.76                 | 11.60  | 43.37           | 31.99  | 81.20   | 50.47   | 30.72   |
| 8         | 3.14                | 2.64                 | 7.83   | 36.19           | 24.41  | 61.23   | 39.49   | 21.74   |
| 9         | 3.53                | 2.65                 | 8.90   | 43.98           | 29.88  | 70.78   | 39.75   | 31.03   |
| 10        | 3.72                | 2.83                 | 9.90   | 34.76           | 23.35  | 57.35   | 34.19   | 23.15   |
| 11        | 3.09                | 2.65                 | 8.68   | 31.39           | 23.76  | 96.34   | 63.33   | 33.01   |
| 12        | 3.73                | 2.64                 | 10.40  | 28.12           | 21.21  | 102.47  | 78.49   | 23.98   |
| 13        | 3.37                | 2.66                 | 9.90   | 29.86           | 23.55  | 96.82   | 76.62   | 20.20   |
| 14        | 3.22                | 2.66                 | 9.90   | 33.63           | 27.76  | 122.70  | 98.13   | 24.56   |
| 15        | 2.24                | 2.64                 | 9.96   | 20.75           | 24.96  | 97.35   | 73.34   | 24.01   |
| Average   |                     |                      |        |                 | 27.37  | 78.61   | 51.02   | 27.59   |

Note: $A$ is the core-specific surface area measured through N$_2$ adsorption experiment. $\rho$ is the rock density. $h$ is water film thickness calculated at $S_{\text{swirr}}$. $r_1$ and $r_2$ are the core average pore throat radius before and after the damage. $r_D$ is the core average pore throat radius reduction which is calculate by the formula of $(r_1 - r_2)$. 

**TABLE 4** Thickness of water film at irreducible water saturation after drainage for 15 core samples

**FIGURE 17** Pore reduction and calculated thickness of water film for 15 tight core samples
5 CONCLUSIONS

This study systematically investigated the effects of rock porosity, gas permeability, and average pore throat radius on WPT damage. Fifteen tight sandstone core samples with permeability of 0.1-1.0 mD were used in performing water imbibition and drainage experiments to simulate the WPT formation process. Gas permeability, both before and after WPT, was measured to determine the degree of WPT damage. The thickness of water film and the size of pore throat reduction were calculated to examine the sensitivity of WPT on effective gas flow channels. The results provide a fundamental understanding of the controlling factors of WPT damage mechanisms. Given that the number of core samples and the differences in permeability of the samples used in the study were limited, future work will use more samples and conduct more tests to improve the qualitative investigation of the controlling factors and mechanisms of WPT. Based on the current work, however, several major conclusions, as summarized below, have been reached:

1. Experimental results showed that an average water saturation of 44.76% was reached after water imbibition and declined to 38.72% after drainage in the fifteen tight core samples. An average increment in water saturation of 19.31% was established for the samples to eventually cause WPT, resulting in a degree of damage to gas permeability in the range of 36.03%-78.10%, with an average value of 59.31%.

2. The comparative analysis showed that the degree of damage to gas permeability increased exponentially with the decline of rock porosity, permeability, and the average pore throat radius while a power-law correlation existed between those factors and water drainage rate. Of these three factors, a convincing relationship of $R^2 = 0.9980$ existed between the degree of pore throat radius reduction and the gas permeability damage rate. This suggests that pore throat size is the most significant factor in WPT damage.

3. Calculations indicate that water film thickness was in the 21.22-38.18 nm range, and the reduced effective gas flow channel was between 20.20 and 45.15 nm after WPT. This verifies that the thickness of water film and pore throat size generally refer to the same micrometer and nanometer level in tight rocks.

4. Gas is trapped by water film or the gas flow channel is decreased by water film are the two primary mechanisms of WPT. Tight rock formations with small pore throats will therefore suffer more severe capillary water

FIGURE 18 Changes of pore throat radius when WPT happens in pore throat: (A) before the WPT damage, the $r$ can preserve well to offer the gas flow channel; (B) after water removal, the increment of water became water film absorbed on the pore wall and the $r$ reduced to become $r_e$; (C) when the thickness of water film is larger than the pore size, capillary-dominated water film formed, which in return will occupy pore space.
imbibition issues and WPT damage than other rock formations.

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