Dynamic Variation of Water Saturation and Its Effect on Aqueous Phase Trapping Damage During Tight Sandstone Gas Well Production

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ABSTRACT: Dynamic variation of water saturation near a wellbore may cause serious aqueous phase trapping (APT) damage in gas well production, especially in partly water-saturated tight sandstone gas reservoirs. In this paper, a prognosis model was deduced and used to characterize the dynamic variation of water saturation. In addition, experimental evaluations of APT damage were conducted to reveal the influence of water saturation changes on APT damage. The results showed that the new model used for the prognosis of the water saturation consists of immobile water and a water film and has good reliability. The results obtained from the model and experiments agreed with each other well; the error is very little and only 2.94%. Decrease of drawdown pressure or increase of hydrostatic pressure will result in increasing water saturation, which is positively correlated with APT damage. The chart curve of APT damage degree versus water saturation indicates that the APT damage degree will increases from 23.14 to 68.27 and 91.37% during the middle-later stages of tight sandstone gas well production, respectively. Finally, results of a sensitivity analysis showed that the surface tension and wetting contact angle have a great significant impact on water saturation. The interfacial modifier could effectively enter the reservoir pores in a near-wellbore zone and continuously act on the reduction of surface tension and increase of wetting contact angle, which is very helpful for releasing APT damage.

INTRODUCTION

Severe production problems are common in tight sandstone gas reservoirs since unfavorable geologic factors (e.g. extra-low initial water saturation, low permeability, and strong water wettability) may induce a series of formation damages.1--3 Aqueous phase trapping (APT) damage, caused by the increase in water saturation near a wellbore, is one of the potential formation damages during tight sandstone gas well production.4--6 Besides, it could also lead to other more serious damages such as clay swelling and fines migration.7,8 Once the heavy APT damage occurred, the gas relative permeability dramatically reduced, and the decline was as high as approximately 95% of the original value.9 Consequently, there were severe challenges to the efficient and economic development of tight sandstone gas wells.

APT is governed by irreversible hysteresis effects that do not allow water saturation to revert to a value lower than the irreducible water saturation of a tight reservoir.10 Previous studies have demonstrated that the irreducible water saturation is dictated by the capillarity in the reservoir; high capillary pressure caused by strong water wettability and narrow pore throats is the main mechanism of water invasion and entrapment.11--14 When the drawdown pressure in a wellbore is far greater than the capillary pressure, the retention of water
may not be serious due to enough energy for driving gas and water out; otherwise, the water saturation near the wellbore would be very high.15,16 According to the relationship between water saturation and relative permeability, it is pointed out that serious APT damage is corresponding to high water saturation, and the threshold pressure gradient effect should not be ignored.17–19 Permeability damage ratio (DR), APT index or modified APT index, phase trapping coefficient (PTC), and phase trapping index (PTI) were proposed to predict the potential tendency of a reservoir for establishment of phase traps.10,20,21 Classically, DR is the most basic and most widely used tool since it is an actual APT test in the laboratory.22 Earlier scholars usually researched the APT damage caused by the working fluid invasion in the processes of drilling and completion, fracturing, workover, and so forth.23–28 The severity of APT damage increases as each of the initial water saturation, permeability, and drawdown pressure decreases, and viscosity of water increases.22,27 Nevertheless, few investigations focused on the research of the APT damage caused by increased water saturation near a wellbore during tight sandstone gas well production.28 Especially, in the partly water-saturated tight sandstone gas reservoirs, the water saturation near a wellbore will continuously increase since the water that comes from the deep zone of reservoirs will be captured in a near-wellbore zone. Therefore, it is necessary to clarify the dynamic variation of water saturation during tight sandstone gas well production as well as quantitatively characterize the APT damage changes.

The pore throat size distribution obtained by analyzing mercury injection capillary pressure (MICP) data is widely used to determine the fractal dimensions of the reservoir rock,29 predict the reservoir permeability based on the acyclic pore model,30–32 estimate the ultimate recovery,33 as well as calculate the variation of water saturation in a near-wellbore zone during gas well production. However, field production data have shown that the calculated results are often smaller than the actual water saturation of the reservoir. That is because the method ignores the fact that there is still some immobile water in the drainable pores.34 The immobile water in the drainable pores exists in the form of a water film.4,35,36 It is like methane adsorbs on the pore surface of shale; it has a certain thickness and volume.37 Thus, the water film in drainable pores is part of the immobile water; the MICP data used to calculate the variation of the water saturation should be corrected.

Therefore, the dynamic variation of water saturation and its effects on APT damage during tight sandstone gas well production were revealed through a series of experiments and model research studies. (i) The MICP test is carried out to characterize the pore throat size distribution of tight sandstone rocks and then obtain the chart curve of cumulative frequency of mobile water versus the pore radius, which is corrected by the volume of the water film in drainable pores; (ii) a prognosis model is sequentially deduced and used to calculate the water saturation during tight sandstone gas well production (i.e., simulating the processes of drawdown pressure decrease and the liquid loading increase); (iii) the chart curve of APT damage degree versus water saturation, established by conducting the experimental evaluation of APT damage, is then used to characterize the APT damage degree in different production periods of tight sandstone gas wells; (iv) suggestions based on the sensitivity analysis of the factors influencing the water saturation are proposed, which provide practical guidelines for efficient and economic development of tight sandstone gas wells.

### EXPERIMENTAL PROGRAM

#### Materials Used.
Previous research studies showed that the number of the Upper Paleozoic sandstone samples, located in Ordos Basin, with the matrix permeability measured under an overburden pressure of less than 0.1 × 10⁻³ μm² accounted for 89% of the total, belonging to typical tight reservoirs.38–40 Thus, seven tight sandstone samples (25 mm diameter × 45 mm length) collected from the Shihezi formation of Permian in the Danidui Gas Field, Ordos Basin, China were used for the MICP test and APT damage measurements. The Shihezi formation that has been previously investigated is the fluvial facies deposit with the characteristics of generally 99–173 m thickness, 2469–2816 m burial depth, and partly water saturated.4 The average petrophysical properties of the tight sandstone samples and Shihezi formation are listed in Table 1, which shows that the petrophysical properties of the tight sandstone samples are similar to those of the reservoir. The X-ray test shows that these tight sandstone samples contain 69.6% quartz, 16.9% muscovite, 6.7% calcite, and 6.8% kaolinite on average.

#### Experimental Method and Procedure.

The PoreMaster 33 porosimeter made by Quantachrome Instruments was used to conduct the MICP test. The pore throat size ranges from 0.0038 to 150 μm could be measured. The experimental method was carried out according to the industry standard of Rock Capillary Pressure Measurement (SY/T 5346-2005).

The APT damage evaluation instrument, as shown in Figure 1, was used to evaluate the degrees of APT damage while increasing the water saturation of tight sandstone rock, which simulated the gradually increasing water saturation in the near-wellbore zone during the gas well production. The experiments were conducted at 20 °C, and the stepwise procedure is as follows:

(i) Dry the tight sandstone sample at 80 °C until the weight of the sample no longer changes with time and measure the initial mass of the sample.

(ii) Place the sample into the core holder, apply 2.5 MPa (363 psi) confining pressure, and measure the initial gas permeability $K_0$ of the sample.

![Table 1. Petrophysical Properties of the Tight Sandstone Samples and Formation](https://dx.doi.org/10.1021/acsomega.0c04993)
(iii) Keep the valve between the core holder and experimental fluid container open and saturate the sample for a time.

(iv) Measure the gas permeability $K_i$ and mass of the sample saturated with formation water.

(v) Repeat the steps (iii) and (iv) to measure the degrees of APT damage in cases of different water saturations. The degree of APT damage can be calculated according to eq 1:

$$D_w = \left( K_o - K_i \right) / K_o \times 100\%$$

where $D_w$ is the APT damage degree, %; $K_o$ is the initial permeability of the sample without water saturation, mD. $K_i$ is the permeability of the sample with water saturation $S_{wi},$ mD.

Theoretical Variation of Water Saturation near a Wellbore during Gas Well Production. Basic Theory and Assumptions. The pore structure of tight sandstone formation is assumed to be represented by the tortuous capillary tube bundles with different diameters. The assumptions used for describing the water discharge in the tortuous capillary tube bundles are as follows: (i) The tortuous capillary tube bundles have TEO (two ends open) boundary conditions. The gas–water flow direction in the capillaries can be assumed to be horizontal. (ii) Each capillary is independent and has a constant diameter and tortuosity along its way. (iii) During the gas well production, the driving mechanism of water drainage from capillaries is the drawdown pressure $\Delta P.$ The capillary pressure $P_c$ caused by the adhesion and cohesion of water molecules in the adhesive layer and the hydrostatic pressure $P_h$ caused by the liquid loading in the wellbore are the resistance pressures.

Thus, without considering other acting mechanisms, the capillary pressure is the resistance pressure for water drainage (Figure 2a, no liquid loading) during the early stage of gas well production. However, during the middle and later stages of gas well production, the hydrostatic pressure caused by the liquid loading would bring back pressure in the well bottom hole. Consequently, the differential pressure acting on the water in the capillaries decreases, which makes water drainage more difficult (Figure 2b).

The drawdown pressure can be then determined by eq 2, which is the difference between the reservoir pressure in the drainage area and the well bottom hole flow pressure.

$$\Delta P = P_p - P_{wf}$$

where $\Delta P$ is the drawdown pressure, MPa. $P_p$ is the reservoir pressure, MPa. $P_{wf}$ is the well bottom hole flow pressure, MPa.

The capillary pressure $P_c$ is the main resistance pressure for water drainage. It can be calculated by eq 3.

$$P_c = \frac{2\sigma \cos \theta}{r}$$

where $P_c$ is the capillary pressure, MPa. $\sigma$ is the interfacial tension of air–formation water (surface tension), N/m. $\theta$ is the contact angle of formation water on a tight sandstone surface, degree. $r$ is the diameter of the capillaries, $\mu$m.

Figure 1. Schematic diagram of the experimental instrument used for APT damage evaluation.

Figure 2. Schematic diagram of the gas–water production in the tortuous capillary tube bundles with different diameters. The gas–water phases flow in the capillary when the radius of the capillary is less than $r_{bk};$ otherwise, the capillary was saturated with water. (a) Stage I: early production; large amounts of tortuous capillaries provide the paths for the flow of the gas–water phases. (b) Stage II: middle and later stages of production; the numbers of tortuous capillaries providing the paths for the flow of the gas–water phases reduced with the decrease of drawdown pressure and the increase of the liquid loading height.
During liquid loading in a well bottom hole, the hydrostatic pressure $P_h$ caused by the liquid loading would bring back pressure in the well bottom hole (i.e., the differential pressure acting on the water in the capillaries $\Delta P_w$ decreases). Thus, the hydrostatic pressure caused by the liquid loading increases the difficulty for water drainage. Since liquid loading is a complex problem, the hydrostatic pressure is assumed to vary from 0 to 1.4 MPa (0–203 psi).

**Critical Capillary Radius for Mobile Water.** Therefore, during the gas–water well production, only when the differential pressure acting on the water in the capillaries ($\Delta P_w$) is greater than or equal to capillary pressure ($P_d$), the water in the capillaries could be effectively discharged. As shown in eq 4

$$\Delta P_w - \frac{2\sigma \cos \theta}{r} = \Delta P - P_h - \frac{2\sigma \cos \theta}{r} \geq 0 \quad (4)$$

When the $\Delta P_w - \frac{2\sigma \cos \theta}{r}$ is equal to zero, the capillary radius calculated by eq 4 is the critical capillary radius for mobile water $r_{ck}$ and is given as follows

$$r_{ck} = \frac{2\sigma \cos \theta}{\Delta P - P_h} \quad (5)$$

in which $r_{ck}$ is the critical capillary radius for mobile water, $\mu m$. Hence, as shown in Figure 2, the water in the capillaries with a radius greater than $r_{ck}$ is mobile water; otherwise, the water is trapped and becomes immobile water.

**Prognosis Model of Water Saturation near a Wellbore.** Although the water in the capillaries with a radius greater than $r_{ck}$ is mobile water, it could not be completely removed due to the wetting effect of water on the inner surface of the rock pores. Previous studies have shown that the retained water exists in the capillaries ($r > r_{ck}$, after the removal of mobile water) in the form of a water film.\textsuperscript{13,35,36} The volume of the water film cannot be ignored and consequently increases the amount of water saturation in the reservoir. The water contains the immobile water in the capillaries with a radius less than $r_{ck}$ and the water film on the inner surface of the capillaries with a radius greater than $r_{ck}$.

**Figure 3** shows the schematic diagram of a water film on the inner surface of a single capillary. The thickness of the water film can be calculated by eq 6.\textsuperscript{35} The appendix shows the detailed derivation of the water film thickness equation.

$$r_w = \frac{6.17 \times 10^{-3}}{\Delta P^{1/3}} \quad (6)$$

where $r_w$ is the apparent thickness of the water film, $\mu m$.

Field production data have shown that the drawdown pressure of Shihezi formation in the early stage of gas well production is about 5 MPa and then decreases gradually to 2 MPa in the middle and later stages of gas well production. Thus, for the immobile water in the drainable pores that exists in the form of water film ($\Delta P \geq P_d$), the apparent thickness of water film, as shown in Figure 4, increases from $3.608 \times 10^{-3}$ to $4.897 \times 10^{-3} \mu m$. Results indicate that the apparent thickness of the water film changes little in cases of different field drawdown pressures; the average value is $4.145 \times 10^{-3} \mu m$, which could be used to represent the apparent thickness of the water film during the whole production stages of the gas well.

According to the figure, the volume of a single capillary can be expressed as

$$V_{\text{single}} = \pi r^2 L \quad (7)$$

in which $V_{\text{single}}$ is the volume of a single capillary, $L$ is the length of a single capillary. Thus, the volume of the mobile water (exclude the water film) in a single capillary could be expressed as

$$V_{\text{moval}} = \pi (r - 4.145 \times 10^{-3})^2 L \quad (8)$$

Then, the volume ratio of the mobile water to the capillaries in the reservoir is given as follows

$$\varphi = \frac{V_{\text{moval}}}{V_{\text{single}}} = \frac{(r - 4.145 \times 10^{-3})^2}{r} \quad (9)$$

in which $\varphi$ is the volume ratio of the mobile water to the capillaries in reservoir, dimensionless. According to the pore throat size distributions of the tight sandstone rock $f(r)$ obtained from the MICP test, the distributions of mobile water in the corresponding pore throat size can be expressed as

$$f_{\text{moval}}(r) = f(r) \varphi \quad (10)$$

where $f_{\text{moval}}(r)$ is the distribution of mobile water in the corresponding pore throat size, $f(r)$ is the pore throat size distribution of tight sandstone rock. Thus, the cumulative distribution frequency of mobile water in the corresponding pore throat size can be expressed as

$$F_{\text{moval}}(r) = F(r) \varphi \quad (11)$$
in which \( F_{\text{moval}}(r) \) is the cumulative distribution frequency of mobile water in the corresponding pore throat size. \( F(r) \) is the cumulative distribution frequency of pore throat size in the tight sandstone rock. Then, the water saturation with considering the volume of the water film could be determined according to \( F_{\text{moval}}(r_{bk}) \).

\[
S_{\text{residual}} = \left( \frac{V_p - V_p \times F_{\text{moval}}(r_{bk})}{V_p} \right) \times 100\% = 100 - F_{\text{moval}}(r_{bk})
\]

(12)

where \( V_p \) is the pore volume. \( S_{\text{residual}} \) is the water saturation with considering the volume of the water film, %.

**RESULTS AND DISCUSSION**

Verifying the Reliability of the Water Saturation Model via Experiments. The curve of \( F\) in Figure 5 obtained from the MICP test presents the cumulative distribution frequency of a pore throat size in the Shihezi tight sandstone reservoir. Results show that the pore throat size is mainly distributed between 0.15 and 0.01 \( \mu \)m. Thus, the cumulative distribution frequency of mobile water in the corresponding pore throat size can be calculated according to eq 11, as shown in the curve of \( F_{\text{moval}}(r) \) in Figure 5. Then, the \( F_{\text{moval}}(r) \) curve can be used to determine the water saturation via equation 5 and equation 12.

To verify the reliability of the model used for determining the water saturation, the water saturation in case of a 5 MPa drawdown pressure obtained from the new model was compared to that obtained from a gas flooding test in APT measurements. Results in Figure 6 indicate that the theoretical water saturation is 46.2% determined via the new model, and the experimental water saturation is recorded as 47.6% on average by testing six tight sandstone rocks. Thus, the results prove that the water saturation obtained from the new method matches the experimental results very well; the error is very little and only 2.94%. The new model used for determining the water saturation has good reliability.

Variation of Water Saturation near a Wellbore during Gas Well Production. Influence of Drawdown Pressure on Water Saturation. As mentioned, field production data obtained from the MICP test presents the cumulative distribution frequency of mobile water in the Shihezi formation.

![Figure 5](https://pubs.acs.org/acsomega/2021/6/5166-5170/figure5.png)

Figure 5. Chart curves of cumulative distribution frequencies of pore throat size and mobile water in the Shihezi formation.

![Figure 6](https://pubs.acs.org/acsomega/2021/6/5166-5170/figure6.png)

Figure 6. Water saturations in case of a 5 MPa drawdown pressure obtained from the new model and experiments.

![Figure 7](https://pubs.acs.org/acsomega/2021/6/5166-5170/figure7.png)

Figure 7. Curves of the critical capillary radius for mobile water and the variation of water saturation near a wellbore versus drawdown pressure.

wellbore was significantly influenced by the drawdown pressure decreasing. The results indicated that with decreasing drawdown pressure, both of \( r_{bk} \) and \( S_{\text{residual}} \) increase and their rising rates increase gradually. For example, when the drawdown pressure decreased from 5 to 3.5 MPa, the \( r_{bk} \) and the \( S_{\text{residual}} \) increased from 0.0268 \( \mu \)m and 46.2% to 0.0382 \( \mu \)m and 49.7% (increased by 42.5 and 7.6%), respectively. However, when the drawdown pressure decreased from 3.5 to 2 MPa, the \( r_{bk} \) and the \( S_{\text{residual}} \) increased from 0.0382 \( \mu \)m and 49.7% to 0.0669 \( \mu \)m and 60.2% (increased by 75.1 and 21.1%), respectively.

Influence of Liquid Loading on Water Saturation. Besides, field production data have also shown that liquid loading becomes more and more serious in the middle and later production stages of a gas well. The height of liquid loading
could lead to the increase of hydrostatic pressure. Therefore, as shown in Figure 2b, in cases of a 2.5 MPa drawdown pressure and a different hydrostatic pressure, the critical capillary radius for mobile water ($r_{\text{hk}}$) and the variation of water saturation near a wellbore ($S_{\text{residual}}$) could be calculated from eqs 5 and 12, respectively.

The curves in Figure 8 have shown that the water saturation near a wellbore was also significantly affected by the hydrostatic pressure. The results demonstrated that with increasing hydrostatic pressure in a wellbore, both $r_{\text{hk}}$ and $S_{\text{residual}}$ increase, and their rising rates increase gradually. For instance, when the hydrostatic pressure increased from 0 to 0.6 MPa, the $r_{\text{hk}}$ and the $S_{\text{residual}}$ increased from 0.0535 µm and 55.6% to 0.0704 µm and 61.3% (increased by 31.6 and 10.3%), respectively. However, when the hydrostatic pressure increased from 0.8 to 1.4 MPa, the $r_{\text{hk}}$ and the $S_{\text{residual}}$ increased from 0.0787 µm and 63.9% to 0.122 µm and 75.3% (increased by 55.0 and 17.8%), respectively.

**Effect of Water Saturation on APT Damage.** APT damage degrees in cases of different water saturations have been given by conducting APT damage evaluations of six sandstone rocks. The data have been analyzed and fitted by the method of least squares to see how much the changing water saturation would influence the degree of APT damage. As shown in Figure 9, the curve of the APT damage degree versus water saturation indicates that the water saturation has a significant influence on the APT damage degree. The APT damage degree initially increases rapidly and then at the later stage increases slowly with increasing water saturation. This indicated that the gas well production would be sensitively dependent on the water saturation during the early and middle stages of the development of a tight sandstone reservoir.

As discovered in previous studies, an ultra-low water saturation has been confirmed in the tight sandstone gas reservoir in Ordos Basin by sealed coring and log interpretation. The initial water saturation in tight gas reservoirs is about 20%, which is far below the irreducible water saturation. When the gas well is open for production, the water saturation near a wellbore would increase gradually. According to the variation of water saturation predicted by the new model in Figure 7 and Figure 8, as well as the field production data, gas well production goes through different stages of water saturation. The 20% water saturation represents the water saturation in the initial stage of gas well production. The 46.2% water saturation in cases of a 5 MPa drawdown pressure without liquid loading represents the water saturation during the early-middle production stage of a gas well. The 75.3% water saturation in case of a 2.5 MPa drawdown pressure with 1.4 MPa hydrostatic pressure represents the water saturation in the later production stage of a gas well.

Therefore, the APT damage degree in the Shihezi formation would increase from $D_{g}$ corresponding to 20% water saturation to $D_{1}$ and $D_{2}$ corresponding to 46.2 and 75.3% water saturations, respectively, during the all the production stages of a gas well. They are 23.14, 68.27, and 91.37%, respectively, according to the chart curve in Figure 9 (data of APT damage degree in case of different water saturations were obtained by measuring six rock samples in Table 1). The APT damage degree increased with an increase of 195 and 295%, respectively. Thus, we can conclude that the APT damage may be the main factor of formation damages during the production of gas wells for partly water-saturated tight sandstone gas reservoirs.

To reduce the APT damage degree, the sensitivity analysis of the factors influencing the water saturation will be carried out in the following section. The research results will provide the way for guiding the improvement of aqueous trapping removal techniques, which are critical for increasing the productivity of the tight sandstone gas wells and obtaining the ultimate high recovery rate of gas resources from the tight sandstone reservoirs.

**Sensitivity Analysis of the Factors Influencing the Water Saturation.** Eq 12 indicates that the water saturation $S_{\text{residual}}$ of a formation depends on the critical capillary radius $r_{\text{hk}}$ and a positive correlation existed. The greater the $r_{\text{hk}}$, the higher the $S_{\text{residual}}$. The $r_{\text{hk}}$ is calculated by eq 5, and it is found that the parameters of surface tension, wetting contact angle, and hydrostatic pressure are variable. Of these, the hydrostatic pressure effecting the $r_{\text{hk}}$ and $S_{\text{residual}}$ has been demonstrated before; a foam agent could be used to remove the liquid loading in a wellbore. In addition, ΔP in eq 5 is the drawdown pressure, and it is a constant during the short-term gas well production. Thus, the factors influencing the water saturation are mainly the surface tension and wetting contact angle.

**Influence of Surface Tension on Water Saturation.** Figures 10 and 11 show the curves of surface tension versus critical

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**Figure 8.** Curves of the critical capillary radius for mobile water and the variation of water saturation near a wellbore versus hydrostatic pressure.

**Figure 9.** Chart curve of APT damage degree vs water saturation.
capillary radius and water saturation. They are calculated in case of a 2.5 MPa drawdown pressure, 23° wetting contact angle, without or with considering 1.4 MPa hydrostatic pressure, respectively. Results show that reducing the surface tension is of great significance to decrease the critical capillary radius and water saturation. For instance, when the drawdown pressure is 2.5 MPa and the height of liquid loading is zero (case 1), the $r_{bk}$ and $S_{\text{residual}}$ are 0.054 μm and 55.6% in case of a 0.0727 N/m surface tension, respectively, whereas they are 0.015 μm and 43.6% in case of a 0.02 N/m surface tension, respectively. They decrease by 72.22 and 21.58%, respectively. The APT damage degree decreases from 80.27 to 63.74% (reduced by 20.59%) by querying the chart curve in Figure 9, as shown in Figure 12. Similar results are observed with considering a 1.4 MPa hydrostatic pressure. The $r_{bk}$ and $S_{\text{residual}}$ are 0.122 μm and 75.3% in case of a 23° wetting contact angle, respectively, whereas they are 0.033 μm and 48.1% in case of a 0.02 N/m surface tension, respectively. They decrease by 72.95 and 36.12%, respectively. The APT damage degree decreases from 91.37 to 71.20% (reduced by 22.08%) by querying the chart curve in Figure 9, as shown in Figure 12. Similar results are observed with considering a 1.4 MPa hydrostatic pressure. The $r_{bk}$ and $S_{\text{residual}}$ are 0.122 μm and 75.3% in case of a 23° wetting contact angle versus critical capillary radius and water saturation in case of a 2.5 MPa drawdown pressure without liquid loading.

The interfacial modifier that reduces interfacial tension of air–formation water (surface tension) is of significant importance for releasing APT damage. Especially, the wetting contact angle is conducive to the decrease of the critical capillary radius and water saturation. For example, when the drawdown pressure is 2.5 MPa and the hydrostatic pressure is zero, the $r_{bk}$ and $S_{\text{residual}}$ are 0.054 μm and 55.6% in case of a 23° wetting contact angle, respectively, whereas they are 0.010 μm and 42.7%, respectively, when wetting contact angle increases to 80°. They decrease by 81.48 and 23.20%, respectively. The APT damage degree decreases from 80.27 to 62.41% (reduced by 22.25%) by querying the chart curve in Figure 9, as shown in Figure 15. Similar results are observed with considering a 1.4 MPa hydrostatic pressure. The $r_{bk}$ and $S_{\text{residual}}$ are 0.122 μm and 75.3% in case of a 23° wetting contact angle.
angle, respectively, whereas they are 0.023 μm and 45.7%, respectively, when wetting contact angle increases to 80°. They decrease by 81.15 and 39.31%, respectively. The APT damage degree decreases from 91.37 to 67.46% (reduced by 26.17%) by querying the chart curve in Figure 9, as shown in Figure 15.

Therefore, the interfacial modifier should also have the effect of increasing the wetting contact angle that can effectively release the APT damage. Moreover, the interfacial modifier could effectively enter the reservoir pores in a near-wellbore zone and continuously act on the increase of wetting contact angle.

■ CONCLUSIONS

A prognosis model was deduced and used to characterize the dynamic variation of water saturation during gas well production in partly water-saturated tight sandstone gas reservoirs. In addition, experimental evaluations of APT damage were conducted to reveal the influence of water saturation changes on APT damage. The research results are as follows:

(1) The prognosis model used for prognosis of the water saturation consists of immobile water and the water film and has good reliability. The results obtained from the model and experiments agreed with each other well, and the error is very little and only 2.94%.

(2) Decrease of drawdown pressure or increase of hydrostatic pressure (caused by liquid loading) will result in increasing water saturation, which is positively correlated with APT damage. The chart curve of APT damage degree versus water saturation indicates that the APT damage degree will increase from 23.14 to 68.27 and 91.37% during the middle-later stages of tight sandstone gas well production, respectively.

(3) Results of a sensitivity analysis showed that the surface tension and wetting contact angle have a significant impact on the water saturation. The interfacial modifier could effectively enter the reservoir pores in a near-wellbore zone and continuously act on the reduction of surface tension and increase of wetting contact angle, which is very helpful for releasing APT damage.

Therefore, research results of the dynamic variation of water saturation and its effect on APT damage during tight sandstone gas well production could provide practical guidelines for efficient and economic development of tight sandstone gas wells.

■ APPENDIX

The scholar proposed the generalized Young Laplace formula

\[ P_d = \frac{\alpha}{r_w^3} \]

where κ is the average curvature of the solid surface to which the water film adheres, m⁻¹. Since the capillary bundle model is used to characterize the pore structure of a sandstone reservoir, κ is equal to 0.5/r. \( P_d \) is the separation pressure of the water film separated from a solid surface, MPa. \( P_d \) can be calculated according to the empirical equation given by Champion Halsey

\[ P_d = \frac{\alpha}{r_w^3} \]

in which \( \alpha \) is a constant; the more hydrophilic the reservoir is, the greater its value is. According to the experimental results given by Gee et al., the value of \( \alpha \) is \( 1.187 \times 10^{-7} \) while the water adheres to the strongly hydrophilic quartz surface of tight sandstone rocks. Thus, inserting eq 13 (appendix-2) into eq 14 (appendix-1) yields eq 15 (appendix-3).

\[ r_w = \left( \frac{1.18 \times 10^{-7}}{P_c - 2\kappa} \right)^{1/3} \]

For a strongly hydrophilic tight sandstone reservoir, the drawdown pressure \( \Delta P \) is equal to \( P_i \); the immobile water in the drainable pores exists in the form of a water film. Thus, according to \( \Delta P = P_i = 2\kappa/r \), eq 15 can be simplified as eq 16.

\[ r_w = \frac{6.17 \times 10^{-3}}{\Delta P^{2/3}} \]

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The authors wish to thank Prof. Zhong for her technological help. This work was supported by the Foundation of Department of Science and Technology of Sichuan Province (2019YJ0406).

Acknowledgments

The authors declare no competing financial interest.

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