Experimental Simulation on the Influencing Factors of Sand Production in H Gas Storage, Xinjiang, China

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ABSTRACT: Affected by the complex operation mode of strong injection and strong production, sand production can seriously affect the life cycle and peak shaving capacity of gas storage. In this paper, combined with the actual production situation of China’s largest gas storage (H Gas Storage), the effect of the gas flow rate, production pressure difference, formation pressure drop, permeability, and water saturation on sand production was systematically analyzed via an indoor sand production simulation experiment. The results showed that from the initial flow rate of 1.88 L/min to a critical flow rate of 3.87 L/min, the core permeability and the stage sand production continued to increase; however, during the flow rate from 3.87 to 8.58 L/min, the core permeability and the stage sand production decreased gradually. The whole process showed that only a small amount of free sand was produced in the early anhydrous production stage. Proper sand production in this stage can make the rock permeability and the gas production grow to a certain extent. But when the gas flow rate reached 3.87–8.58 L/min, pore throats were blocked by sand particles of large sizes. When all sand particles were carried away by the gas flow, no sand production occurred and the rock permeability remained unchanged. In this experiment, the critical pressure difference was 5 MPa. Under the same production pressure difference, the greater the rock permeability, the greater the stage sand production; similarly, under the same rock permeability, the greater the production pressure difference, the greater the stage sand production. In the case of high rock permeability, sand production occurred when the displacement pressure difference was 2 MPa. For the formation pressure drop, sand production occurred when the effective stress reached 10 MPa; furthermore, when the effective stress reached 16.5 MPa, the stage sand production reached the largest value; finally, when the effective stress reached 28 MPa, no sand production occurred anymore. Sand production was easy to occur in cores containing water, which was related to the hydration and swelling of clay minerals, the increase of seepage resistance in gas–water two-phase fluids, and the increase of shear stress in pore throats.

1. INTRODUCTION

H Gas Storage in the Xinjiang region is the largest underground gas storage in China with a storage capacity of more than 100 × 10⁸ m³. The original gas reservoir was converted into a gas storage facility in 2013. At present, it has completed seven cycles of gas injection and production operations. Affected by the strong injection and strong production operation modes, the reservoir is prone to have sand production risks when the gas production rate reaches more than 10 times that of the normal gas development stage. Sand production can seriously affect the life cycle and peak shaving capacity of the gas storage.

Sand production can cause the pore throats to be blocked, which in turn leads to a significant drop in reservoir permeability. In severe cases, it can also cause the wall of wells to collapse. Some basic experiments were conducted previously to study the controlling factors of sand production. For example, the “sand arch phenomenon” was discovered by Terzaghi et al. based on laboratory experiments. Stein found that the shear strength of rocks has a certain influence on sand production. Vaziri et al. established a fluid–solid coupling prediction model of sand production, which proved that rock permeability has a significant impact on sand production. Yue et al. found that the Forchheimer model was the most effective for the calculation of the critical sand production pressure difference in Donghe Oilfield. Yao et al. established a prediction model of sand production considering production factors, completion factors, and in situ stress states. Li et al. conducted a quantitative prediction of sand production in gas wells based on the numerical simulation of in situ stress around the well. Wang et al. systematically studied the
Figure 1. Experimental device for the sand production simulation. (1) Nitrogen bottle; (2) high-pressure nitrogen charging vehicle; (3) intermediate container (gas); (4) confining pressure pump; (5) core holder; (6) wet gas flowmeter; (7) gas compressor; (8) high pressure, constant speed, and constant pressure pump (double cylinder); (9) intermediate container (stratum water); and (10) electronic balance (conical flask).

microscopic sand production morphology and sand production mechanism of weakly cemented reservoirs based on visual experiments. Zhao et al. conducted a quantitative assessment of sand production risks in conventional sandstone gas reservoirs using discrete element theory. Liu et al. clarified the sand production mechanism of moderately consolidated sandstone using rock mechanics experiments. The above studies only focus on one aspect or several aspects that lead to sand production. However, there are few studies on the analysis of the influencing factors of sand production in gas reservoirs through a systematic experimental design.

Therefore, in this paper, combined with the actual production situation of China’s largest gas storage (H Gas Storage), the effect of gas flow rate, production pressure difference, formation pressure drop, permeability, and water content on sand production was systematically analyzed via an indoor sand production simulation experiment. This research can provide scientific guidance for ensuring the long-term safe operation of large gas storages worldwide.

2. DATABASES AND METHODS

2.1. H Gas Storage. The strata in the study area revealed by the drilling include Paleozoic, Triassic, Jurassic, Cretaceous, Paleogene, and Neogene from bottom to top, all of which are continental clastic deposits. The total deposition thickness is greater than 10,000 m. Moreover, the target layer of H gas storage is developed with medium-porous and medium-permeable sandstone reservoirs and is located in the second member of the Paleogene Ziniquanzi Formation (E1z2). The lithologies of the target layer include fine sandstone, unequal grained sandstone, and siltstone. According to the thin section observations under a microscope, the main pore types of the reservoirs in the Ziniquanzi Formation are intergranular pores, followed by intergranular dissolved pores and intragranular dissolved pores. The content of intergranular pores is 0–95%, with an average of 62%, the content of intergranular dissolved pores and intragranular dissolved pores is 5–100%, with an average of 36%, and the content of intragranular dissolved pores is 0–30%, with an average of 2%. The designed gas storage capacity is $107.0 \times 10^8$ m$^3$, and the working gas volume is $45.1 \times 10^8$ m$^3$.

2.2. Periodic Gas Injection and Production Operation. At present, H Gas Storage has a total of 36 wells, including 30 injection–production wells (29 vertical wells and 1 horizontal well), 4 monitoring wells, and 2 sewage reinjection wells. The designed upper limit pressure is 34.0 MPa, the lower limit pressure is 18.0 MPa, the cushion gas volume is $61.9 \times 10^8$ m$^3$, and the additional cushion gas volume is $16.5 \times 10^8$ m$^3$. When the peak gas bearing capacity is $20.0 \times 10^8$ m$^3$, the upper limit pressure reaches 34.0 MPa and the lower limit pressure reaches 26.0 MPa. In addition, the gas injection cycle was set as 180 days, and the gas production cycle was set as 150 days. During the normal peak shaving period, the average daily gas injection volume is $1300 \times 10^8$ m$^3$, and the average daily gas production volume is $1333 \times 10^8$ m$^3$.

After seven complete injection–production operation cycles of H Gas Storage, the volume of periodic gas injection and production gradually increased. In the first four operation cycles, gas injection was greater than gas production, and the formation pressure increased from 14.4 to 22.32 MPa in the first cycle. At the end of the seventh cycle, the formation pressure reached 34 MPa.

2.3. Physical Simulation of Sand Production. In this study, an indoor physical simulation experiment was designed to study the influencing factors of sand production in a gas reservoir. The cores were collected in Well HUKJ3 from H Gas Storage, and the experimental device is shown in Figure 1. It was composed of a core holder, a high-pressure nitrogen charging vehicle, a high pressure, constant speed, and constant pressure pump, a confining pressure pump, a gas compressor, and a vacuum saturation device. Among them, the nitrogen filling equipment and the constant speed constant pressure pump provide the power of gas flow. In addition, some other equipment such as wet flow meters and electronic balances.
were used for real-time measurements of experimental parameters such as fluid flow and sand production amount. Experimental operation steps are as follows:

(1) The length and diameter of the long core were measured before the experiment, and then the long core was vacuumed under a closed condition and saturated with water for 960 min (ensuring full saturation with water).

(2) The core sample was placed in an oven at 100 °C and dried for 12 h, and then the weight of the core sample was weighed.

(3) Different devices were assembled together and the device was tightly sealed. Then, the core was put into the core holder, and a confining pressure at least 3 MPa greater than the inlet pressure was applied. Nitrogen was used to generate the pressure in the experiment.

(4) The gas flow was measured using a gas flowmeter. After every 40 min of fluid displacement, a new gas flow rate was applied and the gas permeability and sand production amount were calculated. After each gas flow rate experiment was over, the core was taken out and its dry weight was measured. The experiment was repeated until the end.

(5) On the basis of step (3), the production pressure difference (or gas drive pressure difference) was applied from 0.5 to 8 MPa. The effective stress was maintained at 3 MPa by adjusting the displacement pressure and confining pressure.

(6) On the basis of step (3), cores with different permeabilities were selected for fluid displacement under different displacement pressure differences for 40 min. Then, the sand production was calculated by weighing the core before and after the experiment.

(7) On the basis of step (3), the formation pressure drop was simulated by changing the confining pressure. Nitrogen was used to generate the pressure in the experiment. When the two ends of the core reached a stable state (in at least half an hour), the gas flow rate was read, and the rock permeability was measured; then, the core was taken out and dried for 1 h, and the weight of the core sample was weighed.

In this experiment, the petrophysical properties of the rock samples and the configured formation water components are shown in Tables 1 and 2, respectively.

### Table 1. Petrophysical Properties of the Core Samples in the Sand Production Simulation Experiment

| core sample | well name | horizon | depth (m) | length (mm) | diameter (mm) | porosity (%) | permeability (mD) |
|-------------|-----------|---------|-----------|-------------|---------------|--------------|-----------------|
| 1#          | HUKJ3     | E_{1-2} | 3209.0–3214.0 | 50.08 | 25.17 | 19.7 | 616.8 |
| 2#          | HUKJ3     | E_{1-2} | 3468.3–3473.6 | 50.21 | 25.31 | 18.2 | 756.6 |
| 3#          | HUKJ3     | E_{1-2} | 3497.0–3500.6 | 50.22 | 25.23 | 19.4 | 621.5 |
| 4#          | HUKJ3     | E_{1-2} | 3508.5–3513.8 | 50.18 | 25.32 | 16.5 | 71.4 |
| 5#          | HUKJ3     | E_{1-2} | 3540.5–3548.0 | 50.24 | 25.59 | 18.3 | 321.6 |
| 6#          | HUKJ3     | E_{1-2} | 3548.0–3553.5 | 50.17 | 25.26 | 18.9 | 510.3 |
| 7#          | HUKJ3     | E_{1-2} | 3574.0–3578.0 | 50.16 | 25.27 | 17.7 | 600.0 |

### Table 2. Concentration of Various Ions in the Configured Formation Water

| water type | salinity (mg/L) | bicarbonate (mg/L) | chloride (mg/L) | sulfate (mg/L) | calcium ion (mg/L) | magnesium ion (mg/L) | sodium potassium ion (mg/L) |
|------------|-----------------|--------------------|-----------------|----------------|---------------------|----------------------|---------------------------|
| NaHCO₃     | 8599.66         | 323.77             | 3901.84         | 1177.00        | 57.98               | 12.95                | 3126.11                   |

### 3. RESULTS

The interval range of the gas flow rate in this experiment was determined by formula 1. The gas well in the study area used 7 inch casing, 16 holes/m, and the borehole radius \( r_w = 18 \) cm, the effective thickness of the gas layer \( h = 26.25 \) m, and the daily gas production rate ranged from 16 to 120 \( \times 10^3 \) m³/d. Therefore, the determined experimental gas flow rate range was 1.8–13.8 L/min.

\[
\frac{Q}{h} = \frac{1.152wQ_0}{D^2}
\]

where \( Q \) is the actual production, m³/d; \( Q_0 \) is the gas flow rate, mL/min; \( r_w \) is the wellbore radius, cm; \( D \) is the core diameter, cm; and \( h \) is the effective thickness of the gas layer, m.

According to Darcy’s law, the calculation formula of rock permeability \( K \) is

\[
K = \frac{2P_0Q_0 \mu L}{A(p_1^2 - p_2^2)} \times 10^2
\]

where \( K \) is the gas permeability of the rock sample, mD; \( P_0 \) is the atmospheric pressure, MPa; \( Q_0 \) is the gas flow rate when the gas passes through the rock sample under atmospheric pressure \( p_0 \), cm³/s; \( \mu \) is the gas viscosity, mPa·s; \( L \) is the length of the rock sample, cm; \( A \) is the cross-sectional area of the rock sample, cm²; \( P_1 \) is the inlet pressure, MPa; and \( P_0 \) is the outlet pressure, MPa.

Table 3 shows the test results of sand production of core sample #1 under different gas flow rates. The gas flow rate ranged from 1.88 to 12.00 L/min. As the gas flow rate increased, the stage sand production and the rock permeability both showed the characteristic of first increasing and then decreasing. The turning point was around 3.00 L/min.

Table 4 shows the test results of sand production of core sample #2 under different production pressure differences. The production pressure differences were distributed between 0.5 and 8.0 MPa.

Table 5 shows the sand production test results of core samples #3, #4, and #5 under different permeability conditions. It can be seen that with the increase of the production pressure difference, both the stage sand production and the cumulative sand production gradually increased.

Table 6 shows the sand production test results of core sample #6 under different formation pressure drop conditions. The displacement pressure was set to 0.5 MPa, and the confining pressures were applied from 5 to 29 MPa.

The effect of different water saturations (0, 20, 40, 60, and 80%) on sand production was determined in this study. Table 7...
composition. The main lithologies include fine sandstone and siltstone, and the main mineral compositions include clay, quartz, potash feldspar, and plagioclase. Identifications of mineral components under a microscope showed that the content of quartz was distributed between 30 and 60%, and the content of feldspar was distributed between 30 and 50%. The low quartz content of the target layer represents low rock strength (Figure 2a). This is because the quartz component constitutes the skeleton of sandstone, so the higher the quartz content, the higher the rock mechanical strength, and a low quartz content represents a low rock strength. Meanwhile, the high content of feldspar indicates that the antirupture ability of the rock is weak (Figure 2b), and it is an important reason for the loose structures of sandstone.

According to the statistical results, the contents of the clay component of the target layer are distributed between 1 and 40% (Figure 2c–f). Clay minerals are prone to hydration and expansion under the friction of the fluid medium, which in turn causes the pores to be blocked.

Moreover, affected by the hydration expansion of clay minerals, the mechanical strength of the rock will be significantly reduced, and the reservoir is prone to have sand production.

In the production stage for a given gas well, the gas inevitably rubs against the formation rocks during its seepage process. Therefore, the greater the fluid velocity, the greater the frictional force exerted on the surface of rock particles. As the drag force on the surface of the rock particles exceeds the inherent tensile strength of the rock, tensile failure occurs. Furthermore, the mineral particles detach from the rock surface and cause sand production when the fluid flows into the bottom of the well.

The changing characteristics of stage and cumulative sand production and rock permeability under different flow velocity conditions are shown in Figure 3. For rock permeability, it could be found that only a small amount of free sand was scourred and migrated in the core at the beginning of the displacement experiment. Under this condition, the core permeability increased to a certain extent (Figure 3). As the flow rate continued to increase and reached 3.87 L/min, the rock permeability reached a peak, and after that, it started to decrease. Until the flow rate reached 9.00 L/min, the rock permeability decreased to the lowest value. The stage sand production increased with the increase of the gas flow rate in the early stage (Figure 3). When the gas flow rate reached 3.87 L/min, the stage sand production reached a peak value. Thus, 3.87 L/min was defined as the critical flow rate. When the gas flow rate exceeded 4.14 L/min, the stage sand production decreased gradually. Finally, when the flow rate reached 8.58 L/min, no sand production occurred (Figure 3). The cumulative sand production increased with the increase of the gas flow rate in the early stage. When the gas flow rate reached 4.14 L/min, the cumulative sand production increased rapidly. However, when the flow rate reached 5.00 L/min, the increase rate in accumulated sand production became slow gradually, and when the flow rate reached 8.58 L/min, no sand production occurred.

Table 3. Test Results of Sand Production under Different Gas Flow Rates

| flow rate (L/min) | permeability (mD) | stage sand production (g) | cumulative sand production (g) |
|------------------|-------------------|---------------------------|-----------------------------|
| 1.88             | 616.8             | 0.00                      | 0.00                        |
| 1.97             | 617.6             | 0.00                      | 0.00                        |
| 2.35             | 619.4             | 0.00                      | 0.00                        |
| 2.61             | 625.3             | 0.004                     | 0.004                       |
| 2.93             | 630.9             | 0.005                     | 0.009                       |
| 3.53             | 638.3             | 0.016                     | 0.016                       |
| 3.87             | 645.2             | 0.010                     | 0.026                       |
| 4.14             | 653.8             | 0.017                     | 0.043                       |
| 4.62             | 652.1             | 0.016                     | 0.035                       |
| 5.22             | 648.3             | 0.014                     | 0.073                       |
| 6.00             | 619.6             | 0.010                     | 0.083                       |
| 6.67             | 612.5             | 0.009                     | 0.092                       |
| 7.50             | 602.3             | 0.005                     | 0.097                       |
| 8.00             | 597.2             | 0.002                     | 0.099                       |
| 8.58             | 583.3             | 0.000                     | 0.099                       |
| 9.23             | 563.1             | 0.000                     | 0.099                       |
| 10.00            | 563.2             | 0.000                     | 0.099                       |
| 12.00            | 563.0             | 0.000                     | 0.099                       |

Table 4. Test Results of Sand Production under Different Production Pressure Differences

| production pressure difference (MPa) | permeability (mD) | stage sand production (g) | cumulative sand production (g) |
|--------------------------------------|-------------------|---------------------------|-----------------------------|
| 0.5                                  | 756.6             | 0.00                      | 0.00                        |
| 1.0                                  | 756.8             | 0.00                      | 0.00                        |
| 1.5                                  | 757.6             | 0.00                      | 0.00                        |
| 2.0                                  | 759.8             | 0.00                      | 0.00                        |
| 2.5                                  | 763.9             | 0.002                     | 0.002                       |
| 3.0                                  | 769.5             | 0.003                     | 0.005                       |
| 3.5                                  | 770.7             | 0.005                     | 0.010                       |
| 4.0                                  | 770.2             | 0.008                     | 0.018                       |
| 4.5                                  | 756.8             | 0.010                     | 0.028                       |
| 5.0                                  | 732.8             | 0.012                     | 0.040                       |
| 5.5                                  | 720.7             | 0.020                     | 0.060                       |
| 6.0                                  | 716.3             | 0.021                     | 0.081                       |
| 7.0                                  | 709.0             | 0.021                     | 0.102                       |
| 8.0                                  | 701.2             | 0.022                     | 0.124                       |

Table 5. Test Results of Sand Production under Different Rock Permeabilities

| production pressure difference (MPa) | 621.5 (mD) | cumulative sand production (g) | stage sand production (g) | 321.6 (mD) | cumulative sand production (g) | stage sand production (g) | 714 (mD) | cumulative sand production (g) | stage sand production (g) |
|--------------------------------------|------------|-------------------------------|---------------------------|------------|-------------------------------|---------------------------|----------|-------------------------------|---------------------------|
| 1.0                                  | 0.000      | 0.000                         | 0.000                     | 0.000      | 0.000                         | 0.000                     | 0.000    | 0.000                         | 0.000                     |
| 2.0                                  | 0.003      | 0.003                         | 0.001                     | 0.001      | 0.001                         | 0.000                     | 0.000    | 0.000                         | 0.000                     |
| 3.0                                  | 0.009      | 0.012                         | 0.004                     | 0.005      | 0.005                         | 0.002                     | 0.002    | 0.002                         | 0.002                     |
| 4.0                                  | 0.013      | 0.025                         | 0.009                     | 0.014      | 0.014                         | 0.003                     | 0.005    | 0.005                         | 0.005                     |

shows the test results of sand production of core sample 7# under different water saturation conditions.

4. DISCUSSION

4.1. Influence of the Gas Flow Rate on Sand Production. The reservoir rocks (E1−E2) in H Gas Storage have fine particles, high clay content, and low rock cement composition. The main lithologies include fine sandstone and siltstone, and the main mineral compositions include clay,
Finally, when all of the free sand was carried out by the gas, the amount of sand production was becoming less and less. Permeability increased slightly with the migration and subsequently, although the gas permeability and gas production capacity increased slightly. Characterized by a small amount of free sand made the rock water-free production stage of H Gas Storage, sand production in the pores would be displaced. This showed that in the early stage of sand production, the core permeability remained unchanged.35,36 If a dry rock sample was used to perform gas displacement, in this case, only the free sand could be driven out, and the pore structure was ignored.

Table 6. Test Results of Sand Production under Different Formation Pressure Drop Conditions

| displacement pressure (MPa) | confining pressure (MPa) | effective stress (MPa) | stage sand production (g) | permeability (mD) | cumulative sand production (g) |
|-----------------------------|--------------------------|-----------------------|--------------------------|------------------|-------------------------------|
| 0.5                         | 5.0                      | 4.5                   | 0.000                    | 510.3            | 0.000                         |
| 0.5                         | 8.0                      | 7.5                   | 0.000                    | 508.5            | 0.000                         |
| 0.5                         | 11.0                     | 10.5                  | 0.002                    | 502.1            | 0.002                         |
| 0.5                         | 14.0                     | 13.5                  | 0.004                    | 495.9            | 0.006                         |
| 0.5                         | 17.0                     | 16.5                  | 0.009                    | 482.3            | 0.015                         |
| 0.5                         | 20.0                     | 19.5                  | 0.007                    | 470.3            | 0.022                         |
| 0.5                         | 23.0                     | 22.5                  | 0.004                    | 461.7            | 0.026                         |
| 0.5                         | 26.0                     | 25.5                  | 0.002                    | 459.2            | 0.028                         |
| 0.5                         | 29.0                     | 28.5                  | 0.000                    | 459.0            | 0.028                         |

Table 7. Test Results of Sand Production under Different Water Content Conditions

| displacement pressure difference (MPa) | 1   | 2   | 3   | 4   |
|----------------------------------------|-----|-----|-----|-----|
| dry sample gas displacement permeability (mD) | 600.0 | 610.5 | 609.1 | 612.3 |
| stage sand production (g)               | 0.000 | 0.000 | 0.003 | 0.005 |
| cumulative sand production (g)          | 0.000 | 0.000 | 0.003 | 0.008 |
| 20% water saturation permeability (mD)   | 598.3 | 597.9 | 596.4 | 595.8 |
| stage sand production (g)               | 0.000 | 0.004 | 0.009 | 0.013 |
| cumulative sand production (g)          | 0.000 | 0.004 | 0.013 | 0.026 |
| 40% water saturation permeability (mD)   | 596.4 | 595.7 | 594.6 | 593.9 |
| stage sand production (g)               | 0.000 | 0.008 | 0.010 | 0.015 |
| cumulative sand production (g)          | 0.000 | 0.008 | 0.018 | 0.033 |
| 60% water saturation permeability (mD)   | 590.8 | 587.6 | 585.3 | 582.2 |
| stage sand production (g)               | 0.002 | 0.010 | 0.013 | 0.018 |
| cumulative sand production (g)          | 0.002 | 0.012 | 0.025 | 0.043 |
| 80% water saturation permeability (mD)   | 582.3 | 581.4 | 579.5 | 577.6 |
| stage sand production (g)               | 0.005 | 0.016 | 0.019 | 0.022 |
| cumulative sand production (g)          | 0.005 | 0.021 | 0.040 | 0.062 |

occurred, and the accumulated sand production remained unchanged (Figure 3).

Sand production is a very complicated dynamic process. The sand source can be divided into three categories: free sand, denuded sand, and skeleton sand.35,36 If a dry rock sample was used to perform gas displacement, in this case, only the free sand in the pores would be displaced. This showed that in the early water-free production stage of H Gas Storage, sand production characterized by a small amount of free sand made the rock permeability and gas production capacity increase slightly. Subsequently, although the gas flow rate continued to increase, the amount of sand production was becoming less and less. Finally, when all of the free sand was carried out by the gas, the core no longer produced sand anymore.

On the whole, in the early stage of sand production, the core permeability increased slightly with the migration and flow of fine sand particles. As the gas flow rate increased, larger sand particles in the reservoir accumulated in the throats, which narrowed the gaps between the pores and throats in the reservoir and increased the seepage resistance. These factors blocked the pores and throats, and the permeability of the reservoir became much poorer. Finally, when all of the sand particles in the core were removed by the gas, the core no longer produced sand, and the core permeability remained unchanged.

4.2. Influence of the Production Pressure Difference on Sand Production. The greater the production pressure difference, the lower the fluid pressure in the pores of the formation, and the greater the effective stress. When the effective stress exceeds the mechanical strength of the formation, the rock skeleton becomes damaged and sand production occurs.36,38 Regarding the special gas production methods of H Gas Storage with strong injection and strong production, the impact of the production pressure difference on sand production cannot be ignored.

The changing characteristics of stage sand production and rock permeability under different displacement pressure differences are shown in Figure 4. It could be found from the stage sand production curve that the core did not produce sand at the beginning of the experiment. As the displacement pressure difference increased, only a small amount of sand began to be produced gradually. Until the displacement pressure difference increased to 5.0 MPa, the amount of stage sand production increased sharply. Therefore, the critical pressure difference of sand production was considered to be 5.0 MPa. When the displacement pressure difference increased to 8.0 MPa, the increase in the amount of sand production gradually slowed down. Rock permeability increased slowly at the beginning of the experiment. When the displacement pressure difference reached 3.0 MPa, the rock permeability reached its peak value. Furthermore, when the displacement pressure difference exceeded 4.0 MPa, the rock permeability began to decrease.

According to the cumulative sand production curve, the core did not produce any sand at the beginning of the experiment. As the displacement pressure difference increased, the cumulative sand production also increased; when the displacement pressure difference reached about 5.0 MPa, the cumulative sand production had the largest increasing rate.

The rock permeability increased with the increase of the displacement pressure difference. This was because as the gas drive pressure increased, some fine particles in the pores were driven out, and the pore flow capacity was improved.35–37 However, as the displacement pressure difference continued to
increase, the rock permeability decreased gradually. This was because the excessive production pressure difference was equivalent to an extra increase in the confining pressure, and then the rock permeability was continuously reduced due to stress sensitivity. As the confining pressure continued to increase, the rock skeleton was deformed, and tiny particles fell off, which resulted in a continuous increase in sand production.

Therefore, the greater the production pressure difference, the greater the risk of sand production. It is essentially related to the change in the gas flow velocity in the reservoir. Especially in the strong injection and strong production mode of gas storage, the impact of the production pressure difference on the sand production is more obvious.25–28

Figure 2. Field emission scanning electron microscopy images of the target layer. (a) Well HUKJ3, No. 1-1 core sample, fine-grained quartz sandstone, with irregular arrangement of quartz grains; (b) Well HUKJ3, No. 2-1 core sample, long strips of feldspar grains; (c) Well HUKJ3, No. 1-2 core sample, particles covered by kaolinite on the surface; (d) Well HUKJ3, No. 1-3 core sample, kaolinite fillings; (e) Well HUKJ3, No. 2-2 core sample, hair-like illite fillings in the pore; and (f) Well HUKJ3, No. 2-3 core sample, Imon mixed layer.

Figure 3. Changes in stage and cumulative sand production and rock permeability under different flow velocity conditions (core sample 1#).

Figure 4. Changes in stage and cumulative sand production and rock permeability under different production pressure difference conditions (core sample 2#).
4.3. Influence of Core Permeability on Sand Production. Rock permeability determines the flow capacity of formation rocks. The higher the rock permeability, the weaker the cementation strength and the greater the risk of sand production. The influence of rock permeability on the stage and cumulative sand production is shown in Figures 5 and 6, respectively. Under the same production pressure difference conditions, the larger the permeability of the core, the larger the stage and cumulative sand production; similarly, under the same rock permeability conditions, the greater the production pressure difference, the greater the stage and cumulative sand production (Figures 5 and 6). When the rock permeability was 71.4 mD, the core did not produce any sand when the displacement pressure difference was lower than 3.0 MPa; and in the case of high rock permeability, when the displacement pressure difference was only 2.0 MPa, the core began to produce sand. The results showed that the greater the rock permeability, the lower the degree of core cementation and the easier it was for the core to have sand production.

4.4. Influence of Formation Pressure Drop on Sand Production. In the strong gas production process in H Gas Storage, the formation pressure continued to drop. Figure 7 shows the changes in the formation pressure of Wells HUK24 and HUK28 in H Gas Storage.

It can be seen from Figure 7 that the formation pressure of Well HUK24 dropped by about 8–9 MPa from the beginning of the fourth cycle to the end of the seventh cycle, and the formation pressure of Well HUK28 dropped by 7–9 MPa from the beginning of the fifth cycle to the end of the seventh cycle. Formation pressure drop is one of the influencing factors affecting sand production. Figure 8 shows the sand production under different formation pressure drop conditions.

It can be seen from Figure 8 that as the confining pressure increased, the effective stress increased as well, and the rock permeability decreased significantly. During the gas production process, the pore pressure of the reservoir decreased to a certain extent. However, the overburden load remained unchanged. Then, the effective net stress applied on the reservoir increased, and the pores and throats were blocked. This was the main reason for the decrease in reservoir seepage capacity.

At the beginning of the gas displacement experiment, no sand was produced until the effective stress reached 10.0 MPa. Moreover, as the confining pressure increased, the amount of stage sand production first increased and then decreased to a certain extent, while the cumulative sand production continued to increase (Figure 8). When the effective stress was 13.0 MPa, the largest sand production amount was reached. When the effective stress reached 28.0 MPa, the core hardly produced sand. When the confining pressure reached a certain value, the stratum skeleton sand was crushed, the rock permeability decreased significantly and the rock pores were closed. At this time, the free sand can no longer flow freely, and no sand production occurred anymore.

4.5. Influence of Water Saturation on Sand Production. Formation water can react with clay minerals. It can dissolve the cement in the formation and reduce the mechanical strength of the rock. The reservoir of H Gas Storage belongs to weakly cemented sandstone and the clay content is high. Therefore, the formation is more likely to cause sand production after water breakthrough occurred. Wells HUK24 and HUK28 both produce water during gas production, and their water production dynamic curves are shown in Figure 9. According to the experimental results of No. 3-1 sample immersed in formation water for 16 h (Figure 10), the core has changed from a complete cylinder to a loose state.

The relationship between the displacement pressure difference and stage and cumulative sand production under different water saturations is shown in Figure 11. Under the same water saturation conditions, both the stage and cumulative sand production increased as the displacement pressure difference increased (Figure 11). For the gas displacement of dry samples, the core did not produce sand when the displacement pressure difference was small, while the water-containing core was easier to produce sand. Under the same displacement pressure difference, both the stage and cumulative sand production increased with the increase of water saturation (Figure 11). This is because the clay minerals inside the water-bearing core are easy to be hydrated, thus decreasing the rock strength to a certain extent. In addition, the gas–water two-phase flow significantly increased the seepage resistance of the fluids, which in turn induced larger shear stress in the pores and throats and thus made the internal structures of the core easily damaged. Moreover, the sand-carrying capacity of gas–water two-phase
flow was stronger than the single-phase gas displacement, which also made the formation easier to have sand production.

The relationship between rock permeability and the displacement pressure difference at different saturations is shown in Figure 12. It can be seen from Figure 12 that as the displacement pressure difference increased, the rock permeability of the dry sample continued to increase, while the rock permeability of the water-containing core showed a downward trend. It was caused by the small pores and throats being blocked by large particles of free sand. Under the same displacement pressure difference, the higher the water saturation, the lower the rock permeability. This was because the hydration and swelling of clay minerals caused a significant decrease in core permeability.

For dry samples, the amount of sand production at the outlet end of the core holder during gas displacement was small, or almost no sand was produced; however, when the water saturation of the rock sample increased from 20 to 40%, the amount of sand at the outlet of the core holder was larger. When the water saturation was 40−60%, the increasing rate of sand production tended to slow down. Finally, when the water saturation reached 80%, the sand production of the rock sample increased significantly again. This was due to the massive destruction of internal structures of the core by hydration and swelling under high water saturation conditions.
Combined with the actual operation of H Gas Storage, the production pressure difference, water saturation, and formation pressure are considered to be the most direct factors affecting the sand production. However, in the complex production mode of strong injection and strong gas production, the control of production pressure difference is the most critical for the prevention and control of formation sand production.

5. CONCLUSIONS

(1) In this paper, combined with the actual production situation of China’s largest gas storage (H Gas Storage), the effect of gas flow rate, production pressure difference, formation pressure drop, permeability, and water content on sand production was systematically analyzed via an indoor sand production simulation experiment.

(2) The gas flow rate has a certain influence on sand production. Only a small amount of free sand was produced in the early anhydrous production stage. Proper sand production in this stage can make the rock...
permeability and the gas production grow to a certain extent. But when the gas flow rate reached 3.87–8.58 L/min, the pore throats were blocked by sand particles of large sizes. When all sand particles were carried away by the gas flow, no sand production occurred and the rock permeability remained unchanged.

(3) In this experiment, the critical pressure difference corresponding to the maximum sand production change is 5 MPa. Under the same production pressure difference, the greater the rock permeability, the greater the stage sand production; similarly, under the same permeability, the greater the production pressure difference, the greater the stage sand production. In the case of high rock permeability, sand production occurred when the displacement pressure difference was 2 MPa.

(4) For the formation pressure drop, sand production occurred when the effective stress reached 10 MPa; furthermore, when the effective stress reached 16.5 MPa, the stage sand production reached the largest value; finally, when the effective stress reached 28 MPa, no sand production occurred anymore. Sand production is easy to occur in cores containing water, which is related to the hydration expansion of clay minerals, the increase of seepage resistance in gas—water two-phase fluids, and the increase of shear stress in pore throats.

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Notes
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