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Physical Simulation for Water Invasion and Water Control Optimization in Water Drive Gas Reservoirs

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Abstract

The development of water drive gas reservoirs (WDGRs) with fractures or strong heterogeneity is severely influenced by water invasion. Accurately simulating the rules of water invasion and drainage gas recovery countermeasures in fractured WDGRs, thereby revealing the mechanism of water invasion and an appropriate development strategy, is important for formulating water management measures and enhancing the recovery of gas reservoirs. In this work, physical simulation methods were proposed to gain a better understanding of water invasion and to optimize the water control of fractured WDGRs. Five groups of experiments were designed and conducted to probe the impacts of the distance between the fractures and the gas well, the drainage position, the drainage timing and the aquifer size on the water invasion and production performance of a gas reservoir. The gas and water production and the internal pressure drop were monitored in real time during the experiments. Based on the above experimental works, a theoretical analysis was conducted to quantitatively evaluate the performance of the gas reservoir recovery via the gas well production performance, water invasion, dynamic pressure drop and residual gas and water distribution analysis. The results show that when the fracture scale was appropriate, a gas well drilled close to a fracture (Experiment 1-3) or a high-permeability formation could also produce gas and achieve drainage efficiently. The recovery factor of Experiment 1-3 reached 62.5%, which was 24.6% and 21.1% higher than those of Experiments 1-1 and 1-2, respectively, which had wells drilled in low-permeability areas. Draining water near an aquifer can effectively inhibit water invasion during the early stage of gas recovery. The setup in Experiment 2-1 effectively inhibited

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water invasion and avoided the formation of water-sealed volumes of gas to recover 30% more gas than recovered with that of Experiment 1-1 without drainage wells. A shorter distance between the drainage well and the aquifer increased the drainage capacity and decreased the gas production capacity, respectively (Well 2 at Point A vs Point B). A larger aquifer had a lower gas recovery, which reduced the economic benefit. For example, due to an infinitely large aquifer, the reserves in Experiment 4-1 were developed by a single well, the gas recovery was only 33.4%. These research results are expected to be beneficial for the preparation of development plans and the optimization of water control measures for WDGRs.

Introduction

Most of the gas reservoirs discovered and developed in China are affected by water invasion, albeit to different degrees. Such effects have been observed to be more serious for WDGRs with fractured or highly heterogeneous formations. The edge water or bottom water tends to intrude easily through fractures or high-permeability zones during gas production. This splits the gas reservoir, resulting in water production in the gas wells, which considerably decreases gas production (Beattie and Roberts 1996; Liu et al. 1999; Hernandez et al. 2006; Dotoku et al. 2019).

WDGRs have the advantage of supplemented energy. For a relatively homogeneous reservoir, the water intrudes evenly, forming the so-called tongue, which acts to replenish energy (Agarwal et al. 1965, Farah et al. 2017). However, water intrusion poses a larger risk to gas reservoir development than to oil reservoir development. The edge and bottom water will "channel in" through the high-permeability zones in a fractured or heterogeneous reservoir, decreasing the efficiency of gas reservoir development. After the water in the gas reservoir is discharged, the formation water intrudes through the gas reservoir and will be split due to the formation water invasion via the fractures (or high-permeability zones). Then, some gas zones will be sealed and eventually form a dead zone, resulting in a significant decrease in the ultimate recovery of the gas reservoir. Additionally, after the gas wells are discharged, gas and water two-phase flow occurs in the formation, which will lead to an increased gas reservoir abandonment pressure and decreased gas production. In the later stage, due to the need for drainage to stabilize the production and tap potential, the difficulty and the costs of development increase (Li and Pan 2011).

Numerous efforts have been made regarding gas reservoir water invasion control by researchers in the oil and gas industry. There are currently three main types of water control countermeasures,

i.e., water drainage, gas well deliquification, and water shut-off (Hearn 2010; Yang et al. 2013; Matthey et al. 2017). Water shut-off is performed to reduce the permeability of fractures by injecting chemical agents, such as gelant, into them, thus preventing water invasion. Ghosh et al. (2020) presented experimental results of water shut-off and noted that the reservoir matrix must be well protected while plugging fractures. To achieve this, different agents may need to be injected into the reservoir at different times. This study suggested that it is not easy to solve the problem of water invasion via water shut-off. Among the three types of water control countermeasures, water drainage uses water wells to actively produce water to consume water energy and reduce the pressure difference between the gas zones and water zones to control water invasion. Water drainage, especially a multiwell combined drainage scheme implemented across a gas reservoir, is an active water control strategy that is widely used in practice. However, due to the complex reservoir conditions and water invasion mechanisms, as well as the constraints imposed by the technical, economic, and environmental conditions, it is difficult to determine the best water control measures and timing, posing great challenges to the formulation and implementation of water control development in gas reservoirs (Feng et al. 2015).

Therefore, for formulating water management measures and enhancing the recovery ratio of gas reservoirs, it is important to accurately simulate the water invasion and drainage gas recovery countermeasures in fractured WDGRs to reveal the water invasion mechanism and plan the reservoir development strategy (Warren and Root 1963; Xia 2002; Hearn 2010; Jin and Wojtanowicz 2010; Kabir et al. 2015; Glumov et al. 2017). However, due to the complexity of the water invasion mechanism and the limitations of experimental techniques, there have been few targeted theoretical studies performed on water control in such a WDGR. Lakatos et al. (2009) illustrated the water-induced formation damage via a flow experiment and high-pressure Hg porosimetry of tight sandstone. Li & Zhang (2011) conducted an experimental study of water shut-off by gas wettability alteration and investigated the feasibility of reducing water production in gas wells by changing the wettability of the gas zone. Xu et al. (2019) investigated the water drainage effect of reducing water invasion via physical simulation experiments. Fang et al. (2019) investigated the influence of reservoir parameters on water invasion in fractured carbonate gas reservoirs. A few indoor studies were conducted on the entire development cycle of gas reservoirs, including water invasion in the early stages and water control in the later stages (Rezaee et al. 2013; Liu et al. 2015).

In this work, a typical gas reservoir is adapted as a prototype to establish a geological model considering different fracture and matrix parameters. Such a model is aimed at simulating the relationship between the fractures and gas well locations, the water invasion in fractured WDGRs with different drainage locations, the drainage timing and the water body sizes. The pressure profiles of different gas reservoirs are monitored and recorded during the experiments to reveal the water invasion dynamics, i.e., the water sealing mechanism. Accordingly, reserve development rules and the distribution of the residual gas are analyzed. On these bases, reasonable countermeasures are proposed, providing technical support for the preparation of development plans and water control development measures for this type of gas reservoir.

Experiments

Geological Model

The water control practices in the Longdiao gas reservoir, a Carboniferous gas field in eastern Sichuan, China, reflect the complexity and challenges of on-site water control (Chen et al. 1999; Yang et al. 2003; Gou et al. 2002). Well Chi 39 in the Longdiao gas reservoir is located at the northern end of the Diaozhongba high spot of the gas field, with single-well-controlled reserves of 26.5×10^8 m³. This well was put into production in March 1992. The initial daily gas production rate (Q_g) was 35.0×10^4 m³/d. In March 1994, formation water was suddenly produced at a daily water production rate (Q_w) of 3 m³/d. The daily Q_g was then reduced to 7.3×10^4 m³/d. Studies showed that Well Chi 39 underwent water invasion typical of reservoirs with large fractures: two large water-conducting faults bring water to the Well Chi 39 area, as shown in **Fig. 1**.

In this case, the water invasion control measures for the gas reservoir were as follows:

In May 1998, a large-scale water drainage for pressure relief was performed for Well Chi 27; at the same time, gas lift drainage was conducted for Well Chi 39 using two additional wells for water control. The dynamic monitoring curves of the gas production depicted that the pressure in the water zones of Well Chi 27 was obviously decreased due to the pumping and drainage, and the daily Q_w of Well Chi 39 was effectively stabilized. After pumping was stopped in October 1999, the pressure in the water zones around Well Chi 27 rapidly recovered. The formation filtration conditions at Well Chi 39 deteriorated rapidly, with the rapid decrease in casing pressure. The Q_w increased from 18 m³/d at pumping stoppage to approximately 40 m³/d. The positive and negative production changes indicated that the pumping drainage pressure relief had a significant effect on

inhibiting the further deterioration of water invasion and reducing the water invasion damage. Although there was a favorable trend in the initial stage of drainage, after nearly four years of drainage, the overall water control effect in the area of Well Chi 27 has not achieved its intended purpose. The main reason is that the water displacement from Well Chi 27 did not meet the designed requirement, and the energy of the movable water was greater than predicted. The water control practice applied in the Well Chi 27-39 area shows that the uncertainties of the water-energy prediction and the actual drainage conditions on site are important factors affecting the water control effectiveness in the well area.

The Chi 27-39 well area of the Longdiao gas reservoir mentioned above has the typical characteristics of a WDGR. As shown in **Fig. 2**, three geological models of typical multiscale fractured WDGR are developed, taking the geological and development examples of the gas zone as a prototype. Water invasion and water control experiments are designed and performed. The left end of the model is connected to the aquifer, and the right side is a heterogeneous reservoir, which is composed of fractured zones (FZs) and matrix zones (MZs) with different physical properties. The FZs are located above and below the MZs. The MZs are divided into MZ 1 and MZ 2 according to different physical properties (indicated by the different filling colors in **Fig. 2**). The main differences among the three geological models are the range of the right MZ 2 (see the boundaries of the three models shown in **Fig. 2**) and the location of Well 1. The gas wells in Geological Models 1 and 2 were deployed at MZ 2, representing a gas reservoir with low-permeability matrix barriers; in these cases, the gas wells and aquifer are not completely connected via fractures. In Model 3, Well 1 is directly connected to the FZ, which represents a gas reservoir in which the gas wells are directly connected with the aquifer through fractures. Compared to the other models, in Model 1, Well 1 is the farthest from the FZ; in Model 3, Well 1 is directly connected to the FZ.

Experimental Method

Corresponding to the geological model, a novel experimental device and method for water invasion and water control in a complex and fractured WDGR were proposed and established (**Fig. 3** and **Fig. 4**).

As shown in **Fig. 3**, **Fig. 4** and **Table 1**, the experimental reservoir was mainly composed of four groups of cores with different physical properties. The core holders were equipped with multiple pressure probes to monitor the gas reservoir pressure profile in real time.

Core 1 and Core 3, which were fractured artificially, were used to represent the small-fracture zone (SFZ) and the large-fracture zone (LFZ), respectively, while Core 2 and Core 4 represent the MZs.

Different lengths were selected for Core 4 according to the simulated geological models: 50 cm for Model 1; 25 cm for Model 2; and 0 cm for Model 3. For Well 1 in the three models, the fracture penetration rates were 50%, 67%, and 100%, respectively (**Table 1**).

Five groups of different types of experiments were designed to investigate the main geological and production conditions affecting the water invasion and water control in the gas reservoirs. The purpose, characteristics, models, and gas well parameters of the experiments are shown in **Table 2** and are described in detail below:

The first group of experiments (Group I) was designed to unveil the impact of the positional relationship between the gas wells and FZs on the water invasion. During the single-well production of Well 1, three different geological models were formed by adjusting the length of Core 4, as described above.

The second group of experiments (Group II) was designed to reveal the impact of the drainage positions on the water control effectiveness. Wells 1 and 2 were simultaneously initiated for production, simulating multiple-well drainage and gas production. Note that Well 2 was placed at four different positions (A, B, C, and D) in the FZs in the four different experiments of Group II. A and C were set in the middle of Core 1 and Core 3, respectively. Meanwhile, B and D were 12.5 cm to the left of A and C, respectively.

The third group of experiments (Group III) was designed to conduct research related to the timing of drainage on water control effectiveness. Experiments 3-1 and 3-2 were completed with Geological Model 2, which was compared with Experiment 1-2 (considering the same geological model), and Experiment 3-3 was completed with Geological Model 3, which was compared with Experiment 1-3 (considering the same model).

The fourth group of experiments (Group IV) was designed to investigate the impact of aquifer size on water control effectiveness. Experiment 4-1 simulated gas reservoirs with an infinite aquifer, while Experiment 4-2 simulated gas reservoirs without an aquifer. Experiments 4-1 and 4-2 were compared with Experiment 3-1 because they used the same geological model. The volume of the aquifer in Experiment 3-1 was 15 times the gas reservoir volume.

The purpose of the fifth group of basic experiments (Group V) was a comparative analysis. Experiments 5-1 and 5-2 were conducted with Model 1 and Model 3, respectively, to simulate volumetric gas reservoirs.

In the first to third groups of experiments, the gas reservoirs were connected to the finite aquifer in a total of 10 experiments. Considering that the elastic energy was released from the gas reservoir rocks and the aquifer, an aquifer volume equivalent to 15 times the gas reservoir volume was consistently set in the experiments.

Considering the similar requirements and gas reservoir production matching experiences, the experimental production rate was 15%-30% of the model open flow (Geertsma et al. 1956; Jiao et al. 2019). In this study, the measured open flows of the different models were in the range of 1000-3000 mL/min, so the experimental Q_g met the open flow requirements of 150-900 mL/min. The abandoned production range of the gas reservoir and the detection accuracy of the flow meter was considered in the experimental study. The abandoned production was set to 2.5% of the Q_g . All the experimental gas wells were produced at a production rate of 400 mL/min with an abandonment production constraint of 10 mL/min.

Experimental Procedures

Step 1: Prepare the core models according to the experimental scheme, load all the cores into the core holder, and then add a confining pressure of 35 MPa.

Step 2: Slowly saturate the core model from both ends with nitrogen until the pressure reaches 30 MPa.

Step 3: Load the simulated formation water into a high-pressure resistant container and apply a pressure of 30 MPa. Change the aquifer setup as needed; if it is an infinite aquifer, then connect a constant pressure gas source to the container to provide continuous pressure.

Step 4: Connect the container storing the brine to the core model at 100% nitrogen saturation. According to the experimental scheme, produce the gas well at a production rate of 400 mL/min to simulate gas reservoir exploitation.

Step 5: During gas recovery, the pressure probes set on the core holder record the pressure profile of the core in real time. The instantaneous gas, water production, accumulated gas, water breakthrough time, and other parameters are recorded by the outlet flow meter and the gas-water separator. Stop the experiment when Well 1 or Well 2 reaches the predetermined production target.

Step 6: After the end of the experiment, weigh the cores to obtain the water saturations at different positions.

Results and Discussion

Impact of the Distance Between the Wells and Fractures

In Group I, three different gas reservoir geological models were formed by varying the length of Core 4 to reveal the impact of the distance from the gas well to the fractures on the water invasion and gas production.

Production Performance

The production curves of Group I are plotted in **Fig. 5**. For comparison, the production curves of the volumetric gas reservoir in Experiment 4-2 are also included in **Fig. 5**. The main production parameters are given in **Table 3**.

The experimental results show that the distance between the gas wells and the FZ can greatly influence the production performance and recovery factor (R).

The gas wells in Gas Reservoirs 1-1 and 1-2 drilled in the low-permeability MZ 2, and there are barriers in the FZ. Once water breakthrough occurred in the gas wells in both gas reservoirs, the production rate dropped rapidly to the abandonment production rate. Specifically, water breakthrough was observed at 74 mins in Experiment 1-1; then, at 76 mins, the Q_g decreased to the abandonment Q_g due to the water breakthrough. Additionally, water breakthrough was observed at 47 mins in Experiment 1-2; then, at 49 mins, the gas production was stopped. Therefore, only the water production curves of Experiment 1-3 are included in **Fig. 5(b)**. For Experiment 1-3, with the gas well directly connected to the FZ, after water breakthrough, the gas well still produced gas for a long time. This is because the water in Well 1 could be quickly and fully drained during the experiment, although a water breakthrough was observed 22 mins after Well 1 production was initiated, when the production capacity stabilized. Stable production lasted for 32 mins, and both gas and water were produced for 115 min. The R during the stage of producing both gas and water reached 25.6%.

Considering the timing of the water breakthrough, a shorter distance between a gas well and the FZ connected to an aquifer will result in a faster water breakthrough. The impacts of the water invasion and the water production capacities of the gas wells are varied, along with the different

distances between the gas wells and the FZs. Although the Q_g of the three types of gas reservoirs were similar, due to the large differences in the gas reservoir reserves, the R of Experiment 1-1 was only 37.9%, and the R of Experiment 1-2 was 41.4%, while the gas R in Experiment 1-3 in the zone directly connected to the FZ reached 62.5%.

The experimental results show that because the FZ is connected to the aquifer, the closer a gas well is to the FZ, the higher the R is. First, the fractures have a high gas supply capacity because they are high-speed gas flow channels, which results in a stable production capacity of the gas reservoir; consequently, the reserves are developed fast. Second, the gas wells in the FZ can produce gas with water for a long time because continuous drainage consumes the water energy and inhibits the water invasion. Third, due to the high conductivity of the large fractures, even if the water saturation is increased, they still have a high seepage capacity, resulting in stabilized gas production at the gas wells after water breakthrough and maintaining long-term gas and water production. Notably, the conclusions have preconditions. The results on the effect of a fracture on the gas recovery are obtained from these experimental conditions (a specific fracture scale and matrix permeability). Fang et al. (2019) noted that although fractures at certain scales can enhance gas recovery, excessively large fractures would allow water to flow along the fractures, which could rapidly decrease the gas recovery.

Water Invasion Analysis

Currently, the main methods of water invasion degree identification can be divided into three main methods: the pressure drop curve method, the apparent geological reserves method and the water invasion volume coefficient method (Chen 1978; Abdul-Majeed and Al-Assal 1998; Siddiqui et al. 2010; Xu et al. 2020).

Using the water invasion volume coefficient method, the θ ~ R curves of Group I were drawn; details are presented in Appendix A. For comparison, the curve of the basic Experiment 5-2 (curve of the volumetric gas reservoir Model 3 without an aquifer) was also drawn in **Fig. 6**. The relationships between the W_p and the R for Experiments 1, 2 and 3 are also plotted in **Fig. 6** for ease of analysis.

Fig. 6 shows a consistency among the theoretical results. For the volumetric gas reservoir depletion exploitation without an aquifer (Experiment 5-2), the θ ~ R curve basically conforms to the 45° line. In the early stage of production in Group I, the θ ~ R curve curves upward, which

reflects the water invasion into the gas reservoirs. The θ - R curves of the later stage of production for the three experiments show a difference in the water invasion as follows.

1. For Experiments 1-1 and 1-2, the slopes of the θ - R curves do not change considerably, and they always plot above the 45° line, indicating that as the formation water continued to intrude, and effective drainage was not fulfilled. The gas well was directly connected to the FZ in Experiment 1-3. When $R=0.37$ or so, the relative pressure of the drawdown curve begins to shift downward, showing strong drainage characteristics that correspond to the point where the gas well began to produce water. This indicates that the θ - R curve can, in time, accurately reflect the change in the water invasion degree on the basis of an accurate calculation of the average formation pressure and geological reserves. As the W_p of the gas well increases, the relative pressure drawdown curve crosses the 45° line when the R of the reserves R is approximately 0.4 and continues to tilt down, indicating that the net intrusion of the aquifer continued to decrease at this stage and gradually transformed into net production.

2. For Experiment 1-3, the θ - R curve decreases and finally approaches $\theta=0.25$, which is in accordance with the fact that the R of Experiment 1-3 is more than 20% higher than those of Experiments 1-1 and 1-2.

Dynamic Pressure Drop

The gas reservoir material balance method can be adapted to estimate the overall water invasion degree and the R of the gas reservoir. However, to calculate the R of the reservoir and the residual gas distribution in different zones of the gas reservoir, a deep understanding of the residual pressure of different regions of the gas reservoir is needed, and it is necessary to apply the gas reservoir pressure contour method and other methods to study the water sealing condition in the gas reservoir (Xu et al. 2012; Feng et al. 2013). During the experiments, the dynamic pressure of the gas reservoir was monitored in real time to intuitively reflect the distribution of the residual sealed gas in the gas reservoir and the R of the reserves, providing important analytical method and basis for understanding the water invasion rules, the water sealing gas mechanism and the mechanism of the remaining reserve development.

Fig. 7 shows the dynamic pressure drop profile of the volumetric gas reservoir in Experiment 4-2. **Figs. 8-10** show the pressure drop profiles of the water drive in Experiments 1-1, 1-2, and 1-3. For the convenience of analysis, the average pressure gradients in the near-well zones during the

above four experiments are calculated and plotted according to the pressure parameters (Experiments 1-1, 1-2 and 4-2 at both ends of Core 4, and Gas Reservoir 1-3 at both ends of the gas reservoir), as shown in **Fig. 11**.

The experimental results show that the dynamic pressure drop profiles of the volumetric gas reservoir and the WDGRs are significantly different, providing rich information about the gas reservoir dynamics.

The pressures at various positions evenly decreased during the production of the volumetric gas reservoir in Experiment 4-2. When the period of stabilized production ended, the R in the reserves was nearly uniform. When the production was stopped at 88 mins, the residual pressure at the various positions was nearly completely dissipated, which corresponded to a gas R greater than 98%.

Matrix 2 of Gas Reservoir 1-1 had the largest range, and Well 1 was 50 cm from the FZ. The dynamic pressure drop process of the gas reservoir shows that the pressure drop in the entire gas reservoir was relatively synchronous and occurred within the first 20 mins of gas production, indicating that the initial reserve development was balanced and that the reservoir could provide a stable gas supply to the gas well. In this stage, the maximum pressure gradient of the gas supply path of the gas reservoir, which occurs in the near-well area of the low-pressure MZ 2 (Core 4), was only 0.007 MPa/cm (**Fig. 11**). Thereafter, the pressure gradient in the immediate vicinity of the well began to increase rapidly, reaching 0.18 MPa/cm at 25 mins and a peak value of 0.34 MPa/cm at 30 mins before stable production ended. The significant pressure drop funnel that formed around the gas well indicated that a large amount of formation energy was lost in the immediate vicinity of the well, i.e., the MZ. When Well 1 was abandoned and production was stopped, the pressure gradient near the well finally stabilized at 0.38 MPa/cm, and the residual pressure in the peripheral FZs and MZ 1 (Cores 1-3) was as high as 19.6 MPa to 21.6 MPa. A large amount of residual reserves was not developed due to water sealing. The R of the corresponding gas reservoir was only 37.9%.

Well 1 in Experiment 1-2 was 25 cm from the FZs, 50% of the distance in Experiment 1-1. Similar to Experiment 1-1, the initial pressure drop in Experiment 1-2 was synchronous in the entire gas reservoir. In the later stage, due to the intrusion of formation water in the near-well zone (MZ 2), the pressure gradient of the near-well zone increased rapidly. In the process of production decline, the average pressure gradient of the near-well zone was stabilized at approximately 0.74 MPa/cm,

which was the highest value among the three WDGRs, approximately twice that in Experiment 1-1.

Well 1 in Experiment 1-3 was directly connected to the FZs. Its pressure drop profile was significantly different from that of Experiments 1-1 and 1-2. Whether in the early or late stages of development, the R in all parts of the gas reservoir Experiment 1-3 was relatively balanced, and the near-well and peripheral pressures gently and synchronously reduced. Due to the high conductivity of the fractures, gas and water were produced together from the gas well, and the energy of the aquifer was simultaneously reduced. This reduces the physical damage due to water invasion, allowing the gas to flow to the gas well through the fractures.

The gas reservoir pressure drop profiles in **Figs. 8-10** also show that, with only Well 1 in production, the R of the low-permeability MZ 1 (Core 2) surrounded by the FZs at the distal end of the gas well depended on the peripheral FZs (Cores 1 and 3). If the R of the reservoir in the FZ was low (Experiments 1-1 and 1-2), the reserves in MZ 1 were sealed off and could not be developed; if the R of the reservoir in the FZs was high (Experiment 1-3), the MZ 1 R would supply gas to the gas well through the FZs and achieve a high gas reservoir R .

Distribution of Residual Water and Reserves

The cores representing the three types of WDGRs were removed immediately after the gas production experiments ended. Then, the average water saturation of the cores in the different parts of the gas reservoirs was obtained using the weighing method, as shown in **Table 4**.

The experiments show that in Experiments 1-1 and 1-2, the overall average water saturations after production were not very different, both exceeding than 40%. Experiment 1-3 with the gas well connected to the FZs produced gas with water for a relatively long time after water breakthrough was observed in the gas well, and the drainage effect was good. The water saturation was only 32.33%, which was approximately 10% lower than that in Experiments 1-1 and 1-2.

All the experimental results obtained for the three types of WDGRs show that the water invasion in the FZs directly connected to the aquifer was the most serious, and correspondingly, the water saturation was the highest, reaching 40%-55%. Although near-well MZ 2 was the farthest from the aquifer, its water saturation was also approximately 45%. The high water saturation of MZ 2 indicated that the fracture was the main water intrusion channel and that the water spread into the

MZ far from the aquifer via the fracture. This is consistent with the conclusion of Sait (2019) from a study of the water invasion mechanism of a fractured carbonate gas reservoir.

MZ 1, surrounded by the FZs, had the lowest average water saturation for each experimental scheme, i.e., 27.60%, 21.45%, and 9.56% in Experiments 1-1, 1-2 and 1-3, respectively, which were considerably lower than those in other zones. The reason for this is that the main water invasion mechanism of MZ 1, the imbibition effect, was different from those of the other zones. Specifically, the permeability of MZ 1 was 0.67 mD, which was considerably lower than that of the reservoirs in the peripheral FZs, where the gas supply rate was slow and the development of the remaining reserves was delayed. The pressure was always slightly higher than that of the connected FZs (this can be verified with the measured pressure data). Physically, gas and water in porous media cannot flow from a low-pressure FZs to a high-pressure MZ. Therefore, the mechanism of the water invasion in MZ 1 can mainly be the imbibition caused by the capillary force.

Gas reservoirs with different geological conditions and even different zones of the same gas reservoirs may have completely different water invasion mechanisms. Their water saturation and residual gas distributions also may be significantly different.

The relative residual reserves of different zones (the ratio of the residual reserves to the total gas reserves) can be calculated after converting the water saturation to the residual gas saturation while considering the residual pressure and porosity of various zones in the gas reservoir. The specific calculation method is as follows:

$$f = \frac{P_{rk} S_{gk} \phi_k}{\sum_{k=1}^n P_{rk} S_{gk} \phi_k} \quad \dots\dots\dots (1)$$

The proportions of residual reserves in different zones after the production of the three types of WDGRs for Group I were calculated and are shown in **Table 5**.

Table 5 shows that the distribution of the residual reserves in different zones of the same gas reservoir was not uniform. Although the porosity of MZ 1 was not high in the three experiments, the residual reserves of this zone were apparently higher than those of the other zones, taking a high

saturation of residual gas into account. The amount of residual reserves in the near-well MZ 2 in the near-well area of Experiments 1-1 and 1-2 was the lowest. The reserves were concentrated in the peripheral FZs and MZ 1, and the gas reservoir reserves were not recovered uniformly; the difference among the proportions of the residual reserves in the different zones of Experiment 1-3 is no more than 10%, and the reserve development was the most balanced.

Impact of Drainage Positions

The multiwell drainage gas production process is often adopted in the early stage of development in fractured WDGRs. For fractured reservoirs or high-permeability zones connecting to the aquifer, water drainage wells (such as Well Chi 27 in **Fig. 1** and Well 2 in **Fig. 2**) are deployed to block aquifer water intrusion. In Group II, the impact of the drainage position on the water control effect was simulated by adjusting the position of the gas production well. As shown in **Table 2** and **Fig. 3**, Well 2 in Experiments 2-1 and 2-2 was set at Point A in the middle of the LFZ and Point B near the water edge, respectively (the distance between Points A and B was 12.5 cm). Well 2 in Experiments 2-3 and 2-4 was located in the zone with small fractures, at Point C and Point D. In the experiments, the operation of the Well 1 and Well 2 was simultaneously initiated. For joint gas production and water draining, the well that reached an abandoned production rate first, had to keep open until the other well reached the abandonment production rate.

Production Performance

Experiments 2-1 and 2-2 in which the drainage well was set in a LFZ were selected for a comparative analysis. The gas production and water production results of both experiments are shown in **Figs. 12** and **13**. The production parameters are shown in **Table 6**.

Since multiwell water control was conducted in the early stage, the gas R of Experiments 2-1 and 2-2 was significantly improved compared with that of Experiment 1-1 with a single well, Well 1 for production, reaching 72.79% and 78.87%, respectively (the gas reservoir conditions were exactly the same, and the R of Experiment 1-1 was only 37.9%). This shows that in the early stage of development, the gas wells in reasonable positions perform joint drainage, greatly reduce the impact of the water invasion and significantly improve the gas recovery.

The production curve shows that no water breakthrough occurred during the production of Well 1 in the distal MZ in Experiments 2-1 and 2-2 due to the high-efficiency drainage of Well 2. This indicates that joint drainage and gas production effectively prevented the aquifer from invading into

the deep part of the gas reservoir. In Experiment 2-2, Well 2 was closer to the aquifer and had a higher drainage capacity and a lower gas production capacity. The R of Well 2 was 28.58%, which was only 80.6% of that in Experiment 2-1. Experiment 2-2 had a better effect on the overall water control of the gas reservoir. The stable production period of Well 1 at the distal matrix position reached 40 min, and the R was as high as 50.29%, which were 1.48 times and 1.34 times those of the corresponding Well 1 in Experiment 2-1, respectively. The R of the entire gas reservoir reached 78.87%, which was 6.08% higher than that in Experiment 2-1.

Clearly, the drainage gas recovery in Experiments 2-1 and 2-2 was better than Experiment 1-1, not considering the technical limitations and economic costs.

Both production parameters of Experiments 2-3 and 2-4 are tabulated in **Table 6**. The R of the gas reservoirs reached 78.08% and 80.33%, respectively, which were also greatly improved compared with the single-well production in Experiment 1-1: the differences in the production performance metrics of Experiment 1-1 and Experiments 2-1 and 2-2 were noticeable. The impact of the drainage position in the SFZ was small, and the difference in the R did not exceed 2.5%. Water-control Experiments 2-3 and 2-4 had similar drainage effectiveness based on the drainage and gas production capacities of the main drainage well, Well 2. Thus, their drainage functions and the protective effects on the gas reservoirs were not considerably different. Compared with drainage Well 2, which was set in the LFZ (Experiments 2-1 and 2-2), Well 2 in the SFZ (Experiments 2-2 and 2-3) had a delayed breakthrough time, and its drainage speed was slower, but the corresponding gas production capacity increased, and the R reached 44%, which was more than 10%-15% higher than that of Experiments 2-1 and 2-2.

Group II showed that the gas drainage effectiveness and the gas production capacity were significantly affected by the location of the gas well upstream, performing the main drainage function. The distance from the gas well to the aquifer and the seepage capacity of the reservoir in the area were important factors. At the same time, these results also illustrated the complexity of the development of a water control plan. The drainage position should be determined by comprehensively considering the recovery of the entire gas reservoir, the technical conditions on site and the economic benefits.

Water Invasion Analysis

The θ - R curves of Group II are included in **Fig. 14**. For comparison, the θ - R curves of the

volumetric gas reservoirs using the same model (basic Experiment 5-1) are also shown in **Fig. 14**. For the convenience of analysis, the relationships between the W_p and the R of the reserves for the corresponding experiments are also plotted in **Fig. 14**.

The θ - R curves of Group II showed the characteristics of water drainage. As Well 2 in Experiments 2-1 and 2-2 produced water earlier and faster, the relative pressure curve started to decrease earlier, and the rate of decrease was greater, implying a stronger drainage effect. As the production progressed, the curves decreased to greater extents, indicating that as the drainage proceeded, the net water influx was reduced and converted to net water production in the later stage.

In **Fig. 14**, the upward W_p - R curve indicates that the unit gas production corresponded to an increase in both the water production and the water-gas ratio. The water production of the four experiments significantly increased once the R was greater than 50%-60%. Thus, the water-gas ratio of the gas reservoir in the later stage of production increased significantly, which also indicates that only the large-scale drainage in the later stage could maintain the gas production of the gas well. Meanwhile, the corresponding relationship between the W_p and the relative formation pressure decline curve was obvious, indicating that the θ - R relation curve could accurately reflect the water invasion degree of the gas reservoir in a timely manner.

Dynamic Pressure Drop

The dynamic pressure drop profiles of Experiments 2-1 and 2-2 are included in **Fig. 15** and **Fig. 16**. Since water control was performed via both wells in an early stage of gas reservoir development, the pressure profiles of the gas reservoirs of Experiments 2-1 and 2-2 decreased rapidly and simultaneously. The residual pressure was low, which was significantly different from that of Experiment 1-1, as plotted in **Fig. 8**. The high pressure drop funnel that formed in the immediate vicinity of Well 1 in Experiment 1-1 was not observed in Experiments 2-1 and 2-2. This shows that for a fractured WDGR, multiwell water control conducted in the early stage could effectively prevent the aquifer water from intruding the gas reservoir, protect the entire gas reservoir, and greatly improve the R and balance of the gas reservoir development.

As Well 2 was deployed at a different position, the order of development of the remaining reserves in different zones of the gas reservoir changed. In Experiment 2-1, Well 2 was at Point A, in the middle of the LFZ connected to MZ 1. MZ 1 supplied the most gas to Well 2 through the fracture, and the average pressure in that zone dropped rapidly, close to the rate of pressure drop in

MZ 2 connected to Well 1. After producing for 20 mins, the residual pressure almost reached vanished. In Experiment 2-2, Well 2 was closer to the aquifer, and its drainage capacity was higher, so the pressure in the other areas of the gas reservoir, including the SFZ and the MZ in the upper part of the gas reservoir, was simultaneously reduced, which protected the entire gas reservoir more effectively.

Distribution of Residual Water and Reserves

Table 7 provides the average water saturation of the gas reservoir in Group II, which was 22.4% when production ended and significantly lower than that in Experiment 1-1 (41.46% water). Therefore, in the early stage, performing multiwell joint drainage and gas production can effectively prevent water invasion.

Comparing the experimental schemes, such as the large-fracture drainage Experiments 2-1 and 2-2, the average water saturation of the gas reservoir after production was 22.81% and 16.37%, which were lower than 27.32% and 23.22% of the small-fracture drainage Experiments 2-3 and 2-4 and indicated that drainage in the large-fracture can more greatly restrain water invasion.

The production parameters in **Table 6** show that the drainage well located in a large-fracture (i.e., Experiments 2-1 and 2-2) will produce water earlier and more frequently. Based on the above analysis of **Fig. 14**, Well 2 in Experiments 2-1 and 2-2 produces water earlier and faster than that in Experiments 2-3 and 2-4, so its $\theta \sim R$ curve dips earlier and its dip amplitude is larger, implying a stronger drainage effect. Both **Table 6** and **Fig. 14** show that this finding is reliable and accurate, since the drainage effect of large fractures is better and more effective at avoiding water intrusion into the deeper part of the gas reservoir.

When the water is drained at the near-aquifer location in the FZ (Experiments 2-2 and 2-4), the increment of water saturation in the gas reservoir is small, approximately 5%-7% lower than that drained in the middle of the FZ (Experiments 2-1 and 2-3, far from the aquifer). This shows that whether the reservoir permeability is high or low, the drainage of water near the aquifer can better prevent water invasion.

Notably, due to the high-efficiency drainage in the early stage of the experiments, all four experiments successfully protected the low-permeability MZ 1 surrounded by fractures and the low-permeability MZ 2 at the toe of the well. In the large-fracture drainage Experiments 2-1 and 2-2, the water saturation of MZ 1 was increased by only approximately 5%, and almost no water invasion

occurred. In Experiment 2-2, the water content of the distal MZ 2 was increased by only 1.91%.

In general, although the MZ had poor physical properties and low permeability, its R on the whole was higher than that of the FZ connected to the aquifer. This indicated that, on the one hand, due to multiwell drainage, the MZ was basically unaffected by water invasion; on the other hand, as the number of gas wells increased, the gas supply distance from the MZ to the gas wells was greatly reduced, so the reserves could be developed more easily (**Table 8**).

In Experiments 2-1 and 2-2, which drained water along the large fractures, the R of the reserves in LFZ 2 was greater than that in SFZ 1, which was far from Well 2. However, in Experiments 2-3 and 2-4, which drained water along the small fractures, the R in SFZ 1 was better than that in LFZ 2, which was far from Well 2.

Impact of Drainage Timing

As shown in **Table 2**, Experiments 3-1 and 3-2 were conducted with Geological Model 2. At the beginning of Experiments 3-1 and 3-2, only a single well, Well 1, was put into production. Once Well 1 reached the abandonment production rate, Well 2 was immediately opened in Experiment 3-1. The drainage well was set in the middle of the LFZ, and it was produced simultaneously with Well 1. In Experiment 3-2, Well 1 was first shut in and then opened to produce gas 16 hours later. When the production of Well 1 decreased to the abandonment production rate again, drainage Well 2 was set at Point A in the middle of the LFZ and was put on production. The production process lasted until the production of both wells was reduced to the abandonment production rate. Experiment 3-3 was implemented with Geological Model 3. Well 1 was directly connected to the fracture zone (FZ) through the high-conductivity fault zone. Its drainage timing was the same as that of Experiment 3-1.

The above experimental process reflects that the first stage of production in Experiments 3-1 and 3-2 was identical to that in Experiment 1-2 (with the same gas reservoir) for single-well (Well 1) production, except that in the second stage, the increases in Well 2 were added. Similarly, the first stage of Experiment 3-3 was identical to that in Experiment 1-3 of single-well (Well 1) production (for the same gas reservoir). Therefore, the production situation of the first stage of Group III is not repeated.

Production Performance

The production curve and the production parameters after adding Well 2 in the second stage of

production of Group III are shown in **Fig. 17** and **Table 9**, respectively.

As shown in **Table 9**, the gas production and W_p in the original production well, the remote Well 1, were extremely small in the second stage of each of the three experiments. By the end of production, the R of Well 1 was less than 3%, and the W_p was less than 4 mL, which can be neglected. The main gas production could be attributed to the later addition of Well 2.

In the second stage of Experiment 3-1, the R of Well 2 reached 37.6%. The cumulative R of the two stages was 79.9%.

After the wells were shut in for 16 hours in Experiment 3-2, Well 1 was initiated first, in the stage with a R of 2.9%. The water produced was only 3.6 mL. This showed that the water invasion into the gas reservoir formed a strong water seal, making it difficult for gas and water to flow into Well 1. It was difficult to effectively resume the production of Well 1 after a long-term shut in. After that, Well 2 was added, and the R sharply reached 31.7%, which implies effective stimulation. In the two stages, the cumulative R increased to 76%, which was slightly lower than that in Experiment 3-1.

Experiments show that when a single well (Well 1) was put into production, once it was flooded, its production would decrease rapidly and could not be recovered by itself. However, by adding a new gas well, Well 2, in the high-permeability zone of the gas reservoir, the water-sealed reserves in the gas reservoir could be unlocked, which significantly improved the gas R (38.45% and 34.6%). In addition, the later the drainage timing of the drainage well, the more serious the water invasion, the more difficult the development of the water-sealed reserves, and the lower the R of the gas reservoirs.

Compared with the outstanding stimulation effect of adding Well 2 in Experiments 3-1 and 3-2, the gas and Q_w in the second stage of Experiment 3-3 were extremely low. The R was only 5.4%, and the cumulative R of the two stages was 68.7%, which was far lower than that achieved in Experiments 3-1 and 3-2. Well 1 in the gas reservoir of Experiment 3-3 was directly connected to the FZ via a high-conductivity fault zone, where the energy in the gas reservoir was largely consumed in the first stage (the residual relative apparent pressure in Experiment 1-3 was only 0.25, in **Fig. 6**), which was not enough to produce gas from the water-sealed zone; thus, it is not possible to significantly increase the gas production in such gas reservoirs by adding gas wells.

Dynamic Pressure Drop

The dynamic pressure drop profiles of the second stage of Experiment 3-1 are shown in **Fig. 18** (for the first stage, see Experiment 1-2, shown in **Fig. 9**).

In the second stage of Experiment 3-1, after adding Well 2 and producing from the two wells for 5 mins, the pressure drop profile changed. When Well 2 was put into production, the residual reserves in MZ 1 were quickly produced. Since the gas production at Well 2 was stable, a large amount of gas and water was produced. Specifically, the peripheral areas that were difficult to exploit from Well 1 in the first stage were developed by Well 2 (Cores 1-3). Well 2 continued to produce for 184 mins, and the pressure drop profile at the end of the experiment (**Fig. 18(d)**) showed that the gas reservoir was relatively balanced and effectively developed.

At the beginning of the second stage of Experiment 3-2, Well 1 was produced first, and the yield stimulation effect was poor, so the pressure drop profile did not change considerably. After adding drainage Well 2, the change in the pressure drop profile was almost the same as that of Experiment 3-1. To avoid repetition, those results are not described in this paper.

Since the drainage scheme in the second stage of Experiment 3-3 almost failed, the relative formation pressure was unchanged from that of Experiment 1-3, and the pressure profile was also stabilized after the first stage of production.

Distribution of Residual Water and Reserves

The water saturations for different zones after gas reservoir production are presented in **Table 10**. Compared with the four experiments in Group II, in which two wells were combined to control water in the early stage of the experiments, Group III showed that the average water saturation increased to more than 30% (from the 22.4% observed for Group II) due to the delay in the drainage well initiation. This indicates that a delayed drainage led to an increase in the net water influx in the gas reservoir.

In Experiments 3-1 and 3-2, after the second stage of production, the average water content of the gas reservoir decreased to 31.22% and 33.77%, respectively, which were 11.52% and 8.97% lower than that of the first stage (Experiment 1-2, 42.74%), respectively. Thus, by increasing the effective drainage of the drainage well, the water saturation of the reservoir was reduced and the flow resistance was reduced, which laid the foundation for the residual reserves to be developed.

Compared with Experiment 3-1, in Experiment 3-2, Well 1 was shut in, the drainage was

590 delayed, and the average water saturation of the gas reservoir was increased by 2.5%. The maximum
591 increase was in MZ 2 (where Well 1 located), indicating that during the shut in of Well 1, the gas
592 and water were rebalanced under the enormous pressure difference in the near-well area and
593 continued to flow to the near-well area.

594 In Experiment 3-3, at the end of the first stage (Experiment 1-3) of production, the average
595 water content was 32.33%. In the second stage, the water drainage had little effect, as only a small
596 amount of gas and water was produced. The average water saturation dropped by only 1.54%.

597 Compared with Experiment 3-1, the residual reserves of MZ 2 in the near-well area of Well 1
598 in Experiment 3-2 were increased due to the late timing of the drainage, and the gas and water in
599 the gas reservoir were rebalanced within 160 mins after Well 1 was shut in. Under the condition of
600 an enormous pressure difference in the near-well area, the gas and water continuously flowed into
601 MZ 2, which caused the gas and water contents to greatly increase, and the average residual pressure
602 increased by 4.0 MPa. The increase in the water saturation led to an increase in the gas and water
603 seepage resistance, and the difficulty of the development of the remaining reserves increased.
604 Therefore, the proportion of residual reserves in MZ 2 in Experiment 3-2 was significantly greater
605 than that in Experiment 3-1 (**Table 11**).

606 In Experiment 3-3, since the second stage of water drainage had little effect, there is no
607 significant difference in the distribution of residual reserves between the second stage and the first
608 stage (Experiment 1-3).

609 **Impact of the Aquifer Size**

610 As shown in **Table 2**, Experiments 4-1 and 4-2 and Experiment 3-1 were conducted using Geological
611 Model 2 under conditions of an infinite aquifer, no aquifer, and an aquifer 15 times greater than the
612 reservoir. In the early stage of Experiments 4-1 and 3-1, only distal Well 1 was produced. After
613 production in Well 1 was reduced to the abandonment production rate, Well 2, in the middle of the
614 LFZ, was initiated, and the production was combined with Well 1. Once both wells reached the
615 abandonment production rate, the production was stopped. Since Experiment 4-2 considered a
616 volumetric gas reservoir, it was developed only by Well 1.

617 ***Production Performance***

618 The production of Experiments 3-1, 4-1 and 4-2 are shown in **Fig. 19** and **Fig. 20**, and the production
619 parameters are shown in **Table 12**.

Comparing the gas production performance, in the first stage, Well 1 in the MZ in Experiment 3-1 (finite aquifer) exhibited stable production for only 30 min. After 49 mins of production, the abandonment production rate was reached, and the R of the single well was 41.4% (42.9% in total, combined with the second stage). However, for the infinite aquifer in Experiment 4-1, due to the high energy of the aquifer, the water invasion was faster and more serious, which led to a shortened (only 23 mins) stable production period of Well 1 in the MZ. After 35 mins of production, the abandonment production rate was met, and the single-well R was only 33.4% (35.4% in total combined with the second stage).

In the second stage, the same drainage measures were utilized for the same drainage timing used for Experiments 3-1 and 4-1. In Experiment 3-1, the finite aquifer drained from Well 2 with a stable production for 14 mins with a single-well R of 37.6%. In Experiment 4-1, the water drainage was fully developed in Well 2 for the infinite aquifer, and the average drainage rate was 12 times larger than that of the finite aquifer (according to **Table 12**), so only 10 mins of stable production were observed. The single-well R was only 29.1%, which was 8.5% lower than that of Well 2 for Experiment 3-1.

At the end of production, the cumulative gas recovery of the infinite aquifer case was 64.5%, which was 15.95% less than that of the finite aquifer case. The single-well stable production period of the volumetric gas reservoir in Experiment 4-2 was as long as 55 mins, which was more than twice that in Experiment 3-1, and the R was over 98%.

The above experiments show that the aquifer size had a significant impact on gas recovery. For the same geological and production conditions, the larger the aquifer was, the lower the R . Fang et al. (2019) performed water invasion experiments with small fractured cores at different aquifer scales. Their research conclusion is consistent with that from this work, which shows that this conclusion may be universal for fractured gas reservoirs.

Comparing the water production performance, in Experiments 3-1 and 4-1, Well 2 was located in the LFZ with high conductivity and directly connected with the aquifer. Therefore, after Well 2 was initiated, it could quickly produce gas and water. In the finite aquifer Experiment 3-1, after the water production of drainage Well 2 increased sharply during the initial stage of the well startup, the aquifer energy was gradually depleted. Meanwhile, the Q_w gradually decreased to only 0.07 mL/min in the later stage. In infinite aquifer Experiment 4-1, since the aquifer's energy in the

production process was not depleted, the water production of drainage Well 2 rapidly increased and then stabilized at approximately 5 mL/min, indicating that the water invasion rate and the drainage rate reached an equilibrium state. Thereafter, Well 2 continued to produce water at this rate until the end of production. The average Q_w from the infinite aquifer was 5.1 mL/min, which was approximately 12 times of that from the finite aquifer. The W_p was as high as 721.7 mL, which was 9.2 times that of the infinite aquifer.

In the experiments, drainage Well 2 could achieve rapid and large-scale drainage. After the energy of the aquifer in the gas reservoir was released, it would not intrude toward the direction of Well 1. By the end of production, Well 1 in the finite aquifer Experiment 3-1 produced almost no water, and the infinite aquifer Experiment 4-1 also produced only 14.4 mL of water.

Dynamic Pressure Drop

Fig. 21 shows the dynamic pressure profiles of Experiment 4-1 (Geometrical Model 2, infinite aquifer). From the early stage of production of Well 1 until the stable production of the well ended, the reserve development was mainly concentrated in the immediate vicinity of Well 1. The pressure remained almost unchanged due to water invasion on the left side, far from the well area (**Fig. 21(a)**). Well 2 produced a large amount of water, forming a pressure drop funnel around the bottom of LFZ 2 and the connected MZ 1. As production progressed, the pressure drop funnel around Well 2 gradually expanded outward, allowing the undeveloped reserves of the area far from Well 1 (Cores 1-3) to be developed. Due to the infinite volume of the aquifer in this case, the residual pressure of the formation remained high until the gas well was shut in.

Comparing the dynamic pressure drops of Experiments 3-1 and 4-1 (**Fig. 18** and **Fig. 21**), it can be seen that the aquifer size affects the R of the entire gas reservoir. At the end of the stable production of Well 1 in the first stage of Experiments 3-1 and 4-1, the pressure drop funnels in the near-well area (Core 4) were 0.75 MPa and 1.14 MPa, respectively, and the pressure gradient of the infinite aquifer was clearly higher. Until the end of the water drainage process, the average residual pressure of the infinite aquifer case remained higher than that of the finite aquifer case (**Fig. 18(d)** and **Fig. 21(d)**).

Distribution of Residual Water and Reserves

After water drainage was conducted with the newly added Well 2 in Experiments 3-1 and 4-1, the

water saturations of the gas reservoirs were similar, at 31.22% and 34.01%, respectively. The difference is mainly due to LFZ 2, where drainage Well 2 was located. In Experiment 4-1, the water content in the area was as high as 46.51%, which was 7.65% higher than the same area of Experiment 3-1, indicating that the large fractures were the main channels of the water invasion (**Table 13**).

The proportions of the residual reserves in different zones of the gas reservoir after gas production in the two types of aquifers of Experiments 3-1 and 4-1 are shown in **Table 14**.

In Experiments 3-1 and 4-1, compared with other zones, MZ 2 had the highest R of the reservoir; conversely, SFZ 1 had the lowest R in the reservoir. Although MZ 2 had poor physical properties and low permeability, it was farthest from the aquifer but nearest to Well 1, so it had the highest R of the gas reservoir. However, although SFZ 1 had favorable physical properties, it had the worst R because it was directly connected to the aquifer and was the farthest from Well 1 and Well 2.

Conclusions

The following conclusions were drawn according to the above-mentioned work:

1. When the fracture scale is appropriate and the permeability of a matrix zone is low, a production well should be deployed in an area that is close to the fractured zone. Although the fractured zone may lead to a fast water breakthrough, it will also result in a higher capacity for gas production and draining water, which can effectively avoid water invasion from occurring in the low-permeability zone.

2. In different zones of a gas reservoir, the water invasion mechanisms will be different. In a matrix area surrounded by fractures, the water saturation is considerably lower than that in the peripheral fractured zones after production. It is confirmed that the main reason for the water invasion in the matrix area is the imbibition caused by capillary forces.

3. The function of a drainage well varies with its location. A shorter distance between the well location and the aquifer induces a higher drainage capacity and a lower gas production capacity.

4. In the process of development, a gas reservoir will be seriously flooded due to untimely drainage. If the remaining energy of this type of reservoir is insufficient, it is difficult to break the gas reservoir seal, even if more gas wells are drilled later.

5. The larger an aquifer is, the lower its R , and the larger the water drainage required to maintain gas production, resulting in a lower production benefit.

709 **Nomenclature**

710 A_k = Core cross-sectional area measured at each measuring point, cm².

711 B_W = Formation water volume coefficient.

712 B_{gi} = Original natural gas volumetric coefficient.

713 G = Natural gas reserves, 10⁴m³.

714 G_p = Cumulative gas production, 10⁴m³.

715 L_k =Core length measured by each measuring point, cm.

716 P = Current formation pressure, MPa.

717 P_i =Initial reservoir pressure, MPa.

718 P_k = Average formation pressure of the core measured at each measuring point, MPa.

719 P_{rk} = Residual pressure in the cores measured at each measuring point, MPa.

720 $\bar{P}$ = Average formation pressure of the gas reservoir, MPa.

721 R = recovery factor, fraction.

722 S_{gk} = Residual gas saturation measured in the core, fraction.

723 W_e = Cumulative water influx, 10⁴m³.

724 W_p = Cumulative water production, 10⁴m³.

725 Z = Natural gas deviation coefficient at pressure P .

726 Z_i = Natural gas deviation coefficient at pressure P_i .

727 θ = Core porosity measured by each measuring point, fraction.

728 ω = Water invasion volume coefficient.

729 ϕ_k = Core porosity measured at each measuring point, fraction.

730 **Subscripts**

731 k = *property at each measuring point*

732 i = *initial condition*

733 **Acknowledgment**

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Appendix A—Detail of the Water Invasion Volume Coefficient Method

Currently, the main methods of water invasion degree identification were developed based on the gas reservoir material balance equation, so generally, the evaluation results of the three methods for

the same production data are quite similar, as Siddiqui et al. (2010) noted in their work on the application of the general material balance equation.

Two parameters, namely, the gas recovery and the relative apparent pressure of the formation, are utilized in the water invasion volume coefficient method, which is equivalent to the normalized pressure drop curve method. The water invasion volume coefficient method is more suitable for a comparative analysis of water invasion with different gas reserves and formation pressures. However, the water influx volume coefficient method requires more gas reservoir parameters, such as the original gas reserves, compared to the other two methods. As such, the water invasion volume coefficient method was utilized to analyze the water invasion and development performance of the gas reservoir in the experiments.

The water invasion volume coefficient is defined as the ratio of the net water amount invading into the gas-bearing area to the primary reserves of the gas reservoir, namely,

$$\omega = \frac{W_e - W_{pBw}}{GB_{gi}} \quad \text{..... (A-1)}$$

The pressure drop equation of a normal pressure WDGR can also be expressed as

$$\frac{P}{Z} = \frac{P_i}{Z_i} \left(\frac{G - G_p}{G - \omega G} \right) \quad \text{.....(A-2)}$$

The R of reserves is defined as

$$R = \frac{G_p}{G} \quad \text{.....(A-3)}$$

The relative apparent pressure of formation is defined as

$$\theta = \frac{P/Z}{P_i/Z_i} \quad \text{.....(A-4)}$$

From the above relationship,

$$\theta = \frac{1-R}{1-\omega} \quad \text{.....(A-5)}$$

For non-water drive gas reservoirs, $\omega = 0$, and Eq. (5) becomes

$$\theta = 1 - R \quad \text{.....(A-6)}$$

Eq. (5) shows that the angle between the $\theta \sim R$ curve and the longitudinal axis is greater than 45° for WDGRs since the water invasion volume coefficient $\omega < 1$. In contrast, for volumetric gas reservoirs, the angle between the $\theta \sim R$ curve and the longitudinal axis is 45°.

It is difficult to obtain an accurate average formation pressure during actual production. In the experiments, the internal pressures of the gas reservoir are accurately measured in real time at more than 20 measurement points, which provides a sound foundation for accurately obtaining the average

formation pressure of the entire gas reservoir. This is beneficial to analyzing the degree of water invasion in the gas reservoir.

According to the experiments, the pressure and physical reservoir parameters of the different zones of the gas reservoir are different, so the average formation pressure of the gas reservoir is calculated by the weighted average values of the physical parameters related to the reserves:

$$\bar{P} = \frac{\sum_{k=1}^n p_k L_k A_k \phi_k}{\sum_{k=1}^n L_k A_k \phi_k} \dots\dots\dots (A-7)$$

At the same time, due to the large pressure variation range in the gas reservoir during the gas reservoir development process, the value of the nitrogen deviation factor under different pressures should be considered when calculating the apparent formation pressure P/Z .

Compared with the pressure drawdown curve method, the water invasion volume coefficient method requires a more accurate and reliable estimation of the initial in-place reserves of the gas reservoirs, in addition to accurate average formation pressure, to calculate the R of the gas reservoirs, posing additional challenges for gas reservoir developers. In the experiment, the reservoir pore volume and the initial reservoir pressure are already known, so the primary reserves can be accurately obtained.

Appendix B—Figures

Fig. 1—Schematic diagram and production history of Chi 27-39 well in the gas field in eastern Sichuan, China.

Modified according to Gou et al. (2002).

Fig. 2—Multi-well joint water-control geological model for fractured water drive gas reservoirs (three geological models).

Fig. 3—Schematic diagram of the joint water-control experiments (three geological models, Well 2 at points A/B/C/D).

Fig. 4—Joint water-control experimental setup for fractured water drive gas reservoirs.

(a)

(b)

Fig. 5—Production performance of the Group I : (a) Gas production, and (b) Water production of Experiment 1-3.

Fig. 6—Relationship between relative apparent pressure of the formation and R .

Fig. 7—Pressure distributions at different stages of Experiment 4-2: (a) Early stage of production – 10 mins, (b) Early stage of production – 30 mins, (c) End of the stabilized period – 55 mins, and (d) Production halts – 88 mins.

Fig. 8—Pressure distributions at different stages of Experiment 1-1: (a) Early stage of production – 10 mins, (b) Early stage of production – 20 mins, (c) End of the stabilized period – 30 mins, and (d) Production halts -76 mins.

Fig. 9—Pressure distributions at different stages of Experiment 1-2: (a) Early stage of production – 10 mins, (b) Early stage of production – 20 mins, (c) End of the stabilized period – 30 mins, and (d) Production halts -49 mins.

Fig. 10—Pressure distributions at different stages of Experiment 1-3: (a) Early stage of production – 10 mins, (b) Early stage of production – 20 mins, (c) End of the stabilized period – 32 mins, and (d) Production halts - 115 mins.

Fig. 11—Average pressure gradients at different times in the near-wellbore zone of the Group I.

Fig. 12—Gas production of two wells in Experiments 2-1 and 2-2: (a) Gas production of Well 1 located in the MZ, and (b) Gas production of Well 2 located in the FZ.

Fig. 13—Water productions of Well 2 in Experiments 2-1 and 2-2.

Fig. 14—Relationship between relative apparent pressure of the formation and R : (a) Drainage Experiments 2-1 and 2-2 in the LFZ, and (b) Drainage Experiments 2-3 and 2-4 in the SFZ.

Fig. 15—Pressure distributions at different stages of Experiment 2-1 (Well 2 is at Point A): (a) Produced for 10 mins, (b) Produced for 20 mins, (c) Produced for 30 mins, and (d) Gas reservoir production halted at 135 mins.

Fig. 16—Pressure distributions at different stages of Experiment 2-2 (Well 2 is at Point B): (a) Produced for 10 mins, (b) Produced for 20 mins, (c) Produced for 30min, and (d) Gas reservoir production halted at 105 mins.

Fig. 17—Production of Gas Well 2 in the second stage of Group III: (a) Gas production of the gas Well 2, and (b) Water production of the gas Well 2.

Fig. 18—Pressure distributions at different times in the second stage of Experiment 3-1 (after drainage): (a) Well 2 started up – 5 mins, (b) End of the stabilized period of Well 2 – 14 mins, (c) Late production period -40 mins, and (d) Gas well production halted – 184 mins.

Fig. 19—Gas production performance of Experiments 3-1 and 4-1: (a) Gas production of Gas Well 1 in the MZ, and (b) Gas production of the Gas Well 2 at point A.

Fig. 20—Water production of Gas Well 2 in the FZ of experiments 3-1 and 4-1.

Fig. 21—Pressure distributions at different stages of Experiment 4-1 (Model 2, infinite aquifer): (a) Stable production of Well 1 ended -23 mins, (b) End of the stabilized period of Well 2 – 45 mins, (c) Late production period -70 mins, and (d) Gas well production halted-142 mins.

Appendix C—Tables

Core No.	Reservoir types	Length , cm	Diameter , cm	Porosity , %	Permeability ,mD
1	Through-going fracture	50	2.52	5.42	9.68
2	Pore type	50	2.51	4.54	0.67
3	Through-going fracture	50	2.53	5.63	18.08
4	Pore type	50/25/0	2.51	5.91	2.54

Table 1—Basic physical parameters of the four groups of cores used in the experiments

Group No.	Experimental No.	Factors	Experimental characteristics	Location of Gas Well 2	Geological Model	Aquifer
I	1-1	Location relationship between gas wells and fracture zones	Single well production in	n/a	Model 1	Finite aquifer (15 times)
	1-2		Gas Well 1	n/a	Model 2	
	1-3		The distance from Well 1 to the fractured zones are different	n/a	Model 3	
II	2-1	Drainage position	Gas Well 1 and 2 producing at the same time	Middle of large fracture-A	Model 1	Finite aquifer (15 times)
	2-2		Well 2 is set at a different position of the fractured zone	Near water end of large fracture-B	Model 1	
	2-3			Middle of small fracture-C	Model 1	
	2-4			Near water end of small fracture - D	Model 1	
III	3-1	Drainage timing	Well 2 was started up immediately after production was stopped in Well 1	Middle of large fracture-A	Model 2	Finite aquifer (15 times)

			Well 2 was started up in	Middle of large fracture-A	Model 2	
			16 hours after production			
			in Well 1 was stopped			
			Well 2 was started			
			immediately after	Middle of large fracture-A	Model 3	
			production was stopped in			
			Well 1			
IV		Aquifer size	Well 2 was started	Middle of large fracture-A	Model 2	Infinite aquifer
			immediately after			
			production was stopped in			
			Well 1	n/a	Model 2	n/a
			Different Aquifer			
V		Basic experiment	No aquifer, only Well 1	n/a	Model 1	n/a
			was producing			

950 Table 2—Contents and parameters of different groups of experiments

951

Experimental No.	Length of Core 4, cm	Stable production period, min	<i>R</i> during stabilized period, %	Production period, min	<i>R</i> , %	Breakthrough time, min	<i>W_p</i> , ml
1-1	50	30	34.2	76	37.9	74	0.2
1-2	25	30	41.4	49	41.4	47	0.05
1-3	0	32	51.7	115	62.5	22	51.7
4-2	25	55	91.7	88	98.6	n/a	n/a

952 Table 3—Statistics on the production of the Group I and Experiment 4-2

953

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4	Average in the Gas Reservoir
1-1	46.34	27.60	47.47	44.43	41.46
1-2	53.11	21.45	50.73	45.65	42.74
1-3	45.86	9.56	41.56	n/a	32.33

954 Table 4—Water saturation increment in different zones at the end of Group I (%)

955

956

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4
1-1	27.93	32.08	28.51	11.48
1-2	26.93	38.05	29.56	5.46
1-3	29.48	39.69	30.83	n/a

Table 5—Percentage of residual reserves at the end of Group I (%)

Experi mental No.	Gas Well 1 in the distal MZ			Gas Well 2 in the FZ				Whole gas reservoir		
	Stable production period, min	Abando nment time, min	Single well R, %	Breakthrough time, min	Stable production period, min	Abandonment time, min	Single well R, %	Production period, min	Cumulative water production, mL	R, %
2-1	27	29	37.46	5	17	135	35.44	135	83.9	72.79
2-2	40	105	50.29	5	19	44	28.58	105	103.8	78.87
2-3	25	34	33.53	11	23	144	44.44	144	80.2	78.08
2-4	26	65	35.44	6	14	175	44.78	175	86.9	80.33

Table 6—Statistics on the production of Group II

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4	Average water content
2-1	31.99	4.46	31.32	23.46	22.81
2-2	33.01	6.78	23.78	1.91	16.37
2-3	38.09	22.91	33.51	14.78	27.32
2-4	23.27	13.49	41.12	14.99	23.22

Table 7—Water saturation increment in different zones at the end of Group II (%)

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4
2-1	48.62	0.61	36.47	14.30
2-2	42.68	25.76	25.29	6.27
2-3	21.37	28.09	40.49	10.05
2-4	26.13	27.46	35.10	11.30

Table 8—Percentage of residual reserves in different zones at the end of Group II (%)

The Joint production of two wells in the second stage										
Experimental No.	First stage $R, \%$	Gas Well 2 in the FZ					Matrix Well 1			
		Stable production		Abandonment		$R, \%$	Stable production		Abandonment	Cumulative R of the two stages, %
		period, min		time, min			period, min		time, min	
3-1	41.4	14		184		37.6	0		30	79.9
3-2	41.4	10		168		31.7	0		20	76.0
3-3	62.5	1		25		5.4	0		12	68.7

Table 9—Statistics on the production of Group III

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4	Average in the gas reservoir
3-1	37.42	19.74	38.86	28.87	31.22
3-2	40.11	17.74	36.02	41.20	33.77
3-3	45.33	8.05	38.99	n/a	30.79

Table 10—Water saturation increment in different zones at the end of Group III (%)

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4
3-1	41.07	23.08	26.95	8.90
3-2	40.03	14.58	27.93	17.45
3-3	35.64	34.56	29.80	n/a

Table 11—Distribution of residual reserves in different zones at the end of Group III (%)

Experi- mental No.	Gas Well 2 in the FZ					Gas Well 1 in the distal MZ					Cumulative R of the reservoir, %
	Stable production period, min	Downtime , min	Single well R , %	W_p , mL	Stable production period, min	First abandonment time, min	Downtime , min	Single well R , %	W_p , mL		
3-1	14	184	37.6	78.6	30	49	184	42.9	1.1	80.45	
4-1	10	142	29.1	721.7	23	35	142	35.4	14.4	64.50	
4-2	Dry well				55	88	88	98.6	0	98.6	

Table 12—Statistics on the production of Group IV and Experiment 3-1

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4	Average in the gas reservoir
3-1	37.42	19.74	38.86	28.87	31.22
4-1	35.16	19.67	46.51	34.68	34.01

Table 13—Water saturation increment (%) in different zones at the ends of Experiments 3-1 and 4-1

Experimental No.	SFZ 1 - Core 1	MZ 1 - Core 2	LFZ 2 - Core 3	MZ 2 - Core 4
3-1	41.07	23.08	26.95	8.90
4-1	43.48	21.93	26.64	7.95

Table 14—Distribution of residual reserves (%) in different zones at the ends of Experiments 3-1 and 4-1

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1006

Multi-well joint water-control geological model for fractured water drive gas reservoirs (three geological models).

Figure 3

Schematic diagram of the joint water-control experiments (three geological models, Well 2 at points A/B/C/D).

Figure 4

Joint water-control experimental setup for fractured water drive gas reservoirs.

(a)

(b)

Figure 5

Production performance of the Group I : (a) Gas production, and (b) Water production of Experiment 1-3.

Figure 6

Relationship between relative apparent pressure of the formation and "R".

Figure 7

Pressure distributions at different stages of Experiment 4-2: (a) Early stage of production – 10 mins, (b) Early stage of production – 30 mins, (c) End of the stabilized period – 55 mins, and (d) Production halts – 88 mins.

Figure 8

Pressure distributions at different stages of Experiment 1-1: (a) Early stage of production – 10 mins, (b) Early stage of production – 20 mins, (c) End of the stabilized period – 30 mins, and (d) Production halts – 76 mins.

Figure 9

Pressure distributions at different stages of Experiment 1-2: (a) Early stage of production – 10 mins, (b) Early stage of production – 20 mins, (c) End of the stabilized period – 30 mins, and (d) Production halts – 49 mins.

Figure 10

Pressure distributions at different stages of Experiment 1-3: (a) Early stage of production – 10 mins, (b) Early stage of production – 20 mins, (c) End of the stabilized period – 32 mins, and (d) Production halts -115 mins.

Figure 11

Average pressure gradients at different times in the near-wellbore zone of the Group I.

(a)

(b)

Figure 12

Gas production of two wells in Experiments 2-1 and 2-2: (a) Gas production of Well 1 located in the MZ, and (b) Gas production of Well 2 located in the FZ.

Figure 13

Water productions of Well 2 in Experiments 2-1 and 2-2.

Figure 14

Relationship between relative apparent pressure of the formation and " R ": (a) Drainage Experiments 2-1 and 2-2 in the LFZ, and (b) Drainage Experiments 2-3 and 2-4 in the SFZ.

Figure 15

Pressure distributions at different stages of Experiment 2-1 (Well 2 is at Point A): (a) Produced for 10 mins, (b) Produced for 20 mins, (c) Produced for 30 mins, and (d) Gas reservoir production halted at 135 mins.

Figure 16

Pressure distributions at different stages of Experiment 2-2 (Well 2 is at Point B): (a) Produced for 10 mins, (b) Produced for 20 mins, (c) Produced for 30min, and (d) Gas reservoir production halted at 105 mins.

(a)

(b)

Figure 17

Production of Gas Well 2 in the second stage of Group III: (a) Gas production of the gas Well 2, and (b) Water production of the gas Well 2.

Figure 18

Pressure distributions at different times in the second stage of Experiment 3-1 (after drainage): (a) Well 2 started up – 5 mins, (b) End of the stabilized period of Well 2 – 14 mins, (c) Late production period -40 mins, and (d) Gas well production halted – 184 mins.

(a)

(b)

Figure 19

Gas production performance of Experiments 3-1 and 4-1: (a) Gas production of Gas Well 1 in the MZ, and (b) Gas production of the Gas Well 2 at point A.

Figure 20

Water production of Gas Well 2 in the FZ of experiments 3-1 and 4-1.

Figure 21

Pressure distributions at different stages of Experiment 4-1 (Model 2, infinite aquifer): (a) Stable production of Well 1 ended -23 mins, (b) End of the stabilized period of Well 2 – 45 mins, (c) Late production period -70 mins, and (d) Gas well production halted-142 mins.