Numerical simulations of depressurization-induced gas production from hydrate reservoirs at site GMGS3-W19 with different free gas saturations in the northern South China Sea

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Abstract
Class 1 hydrate reservoirs are regarded as the most promising targets for gas production. Previous investigations in the northern South China Sea have proven that the low-permeability hydrate reservoir at site GMGS3-W19 is a Class 1 hydrate deposit. However, the dynamic production behaviors of this type of reservoir are not yet fully understood. Here, we report gas recovery from hydrate reservoirs containing underlying free gas layers with different initial gas saturations and investigate the effects of absolute permeability and depressurization pressure on gas production performance. The results show that high initial gas saturation of the underlying free gas layer and low bottom-hole pressure are advantageous for enhancing the gas production performance. The effects of absolute anisotropic permeability and isotropic permeability on gas recovery from Class 1 hydrate reservoirs are different. For long-term gas production from this hydrate reservoir with any initial gas saturation, a higher horizontal permeability (permeability anisotropy more than 10) in the hydrate layer is remarkably beneficial to stimulate gas extraction and decrease the amount of produced water replenished by inflows from permeable overlying and underlying sediments. Moreover, the gas production rate is highly consistent with the hydrate dissociation ratio, one of the main factors affecting the gas production performance, in Class 1 hydrate reservoirs with different permeabilities. However, for this type of hydrate reservoir with permeability anisotropy larger than 5, the larger the horizontal permeability in the hydrate layer can form more secondary hydrates. The increment in secondary hydrate formation negatively influences the hydrate dissociation ratio and gas recovery. Thus, it is also significant to weigh the permeability anisotropy of the hydrate layer and the secondary hydrate formation amount during the production
1 | INTRODUCTION

Natural gas hydrate (NGH) is regarded as one of the most promising alternative energy resources that is widely distributed in permafrost zones and oceanic sediments. The NGH reservoirs are generally divided into four classes: Class 1 (the free gas layer above which the hydrate-bearing layer exists), 1 Class 2 (hydrate formation overlies a mobile water zone), 2 Class 3 (only one hydrate formation without any underlying zone of mobile fluids), 3,4 and Class 4 (reservoirs with low hydrate saturation and unconfined geological strata near the seafloor, hydrates in fractures, etc.). 5 The percentages of the above four types of reservoirs in nature are expected to be 14%, 5%, 6%, and 75%, respectively. 6 At present, Class 4, representing the largest content, is hard to be a candidate for gas production because of its dispersed distribution. 7 Among the other three classes, Class 1 hydrate accumulations are regarded as the most promising targets since the proximity to the hydration equilibrium at the hydrate-gas interface is favorable to gas recovery. Additionally, the existence of a free gas zone provides a significant contribution to total gas extraction. 8-10

In recent years, several short-term offshore field production tests have been carried out, including two tests in the Nankai Trough in Japan 11-14 and three tests in the Shenhu area 15-17 in China. According to previous field tests, depressurization is regarded as the most promising and feasible method. 18,19

It has been reported that there is a vast large hydrate resource in the South China Sea (SCS). 7 To optimize the field test in this area, the China Geological Survey (CGS) has carried out a series of drilling programs. For example, actual NGH samples were first collected at sites SH2, SH3, and SH7 in the Shenhu area in 2007. 20,21 Later, several Class 1 hydrate accumulations were discovered during the second and third hydrate expeditions at sites W17 and W19. 1 Based on these field studies, in 2017, the first offshore gas hydrate production trial was performed successfully in a clayey silt Class 1 hydrate reservoir, with a total gas production of 3.09 × 10^5 m^3. 15,22 However, the gas recovery rate (average 5000 m^3/d) is still far from the commercial production level. The results indicate that the relatively low gas production rate remains one of the bottlenecks for economic utilization due to the low-permeability sediments. 23 Therefore, how to promote gas production in Class 1 hydrate reservoirs is currently an urgent issue.

The gas production potential of hydrate reservoirs is mainly affected by three factors, including the production method, the configuration of the production well, and the reservoir condition. Although some novel and promising approaches are conducive to stimulating gas production potential from NGH reservoirs, 24-26,28-31,63 gas recovery enhancement is mainly dependent on gas hydrate resources in essence. If the reserves for gas production are deficient, even though the production strategies are strengthened, the enhancement of productivity is still limited. In other words, gas production potential is fundamentally determined by reservoir characteristics. There is no controversy regarding whether the absolute permeability is a key factor affecting the relative and effective permeability of sediments with or without solid hydrate. 32 According to previous research, 33,34 absolute permeability shows the greatest influence on methane hydrate production. Therefore, many modelling studies have been performed to evaluate the effect of the absolute isotropic permeability on the gas production potential. 35,36 Yu et al. 37 indicated that the permeability improvement in the low-permeability silt-dominated layers to enhance gas recovery in the eastern Nankai Trough seemed to be feasible. The sensitivity analysis on depressurization-induced gas production from the Class 1 hydrate reservoir in the SCS performed by Jiang et al. 38 showed that a high absolute permeability could enhance the hydrate dissociation rate. Similar production behaviors were also predicted by Grover et al., 39 Sun et al. 40 and Şükrü and Longinos. 41 In addition, permeability anisotropy (the ratio of horizontal to vertical permeability, i.e., r_{zz} = k_z/k_r) is a ubiquitous characteristic of sedimentary reservoirs in nature and is an important factor determining whether a hydrate reservoir has production potential. 42,43 Permeability anisotropy influences the fluid flow behaviors, pressure propagation, and heat transfer in the reservoir during production. 44 Specifically, increasing horizontal permeability is conducive to hydrate dissociation and fluid migration in the lateral direction, which are essential to long-term gas production. 45-48 Feng et al. 49 investigated the effect of permeability anisotropy on gas production behavior using a horizontal well by depressurization in a sand-dominated hydrate reservoir in the eastern Nankai Trough. The results indicated that high permeability anisotropy can significantly

progress. These findings can contribute to estimating the gas recovery efficiency in Class 1 hydrate reservoirs and optimizing the production process in similar areas.

KEYWORDS

absolute permeability, Class 1 hydrate reservoirs, depressurization, hydrate dissociation ratio, initial gas saturation
promote hydrate dissociation, leading to an increase in gas recovery during long-term extraction. However, the effect of permeability anisotropy on gas production enhancement is inconsistent with the findings of other scholars. Given the debates above, the impact of permeability anisotropy on hydrate development in different reservoirs is still controversial. Moreover, there are few reports on this issue in the low-permeability Class 1 hydrate reservoirs. Hence, whether gas recovery from Class 1 hydrate reservoirs can be enhanced by anisotropic permeability improvement needs further investigation. Meanwhile, the difference in the gas recovery enhancement for this type of reservoir with anisotropic and isotropic permeability is also unclear.

This study mainly investigates the effect of absolute permeability, including anisotropic and isotropic permeability, on gas recovery from Class 1 hydrate reservoirs with different initial gas saturations based on the available data at site W19 in the SCS (Figure 1). It is assumed that water and sand production have already been well managed. Furthermore, it is worth noting that the free gas layer can significantly affect gas production behaviors due to this special characteristic of Class 1 hydrate accumulations. Therefore, accurate gas saturation of the free gas layer can lead to an anticipated result. However, different measurement methods may obtain diverse gas saturation in the free gas layer, causing an unreliable prediction. Because of this variability, some possible gas saturations are first designed in the model to simulate their influences on gas production by depressurization (under constant bottom-hole pressure). Then, the effects of absolute permeability in the hydrate-bearing layer and free gas layer, including anisotropic and isotropic permeability, on the production behaviors are investigated. Meanwhile, the secondary hydrate formations in Class 1 hydrate reservoirs with different gas saturations and permeabilities are calculated, and the relationship between the actual hydrate dissociation ratio and gas production rate is determined. Finally, the bottom-hole pressure on gas production performances in the Class 1 hydrate reservoirs with different permeabilities are also analyzed. The simulation results can contribute to a clear understanding of gas recovery from a Class 1 hydrate reservoir and show some optimal strategies for economic and environmentally safe production from similar hydrate reservoirs.

2 | NUMERICAL MODELS

2.1 | Target reservoir conditions, model construction, and domain discretization

Numerical simulation in this study is performed using the TOUGH+HYDRATE software. It was developed by the Lawrence Berkeley National Laboratory and has been widely used in production prediction due to its high accuracy. The geological system simulated in this paper is located in the Shenhu area (Figure 1). It is in the Pearl River Mouth Basin, one of the most important petrolierous basins on the northern slope of the SCS. In 2013, gas hydrate reservoirs were discovered at site W19 in the Shenhu area. Field drilling and logging indicated that a 38-m-thick high-saturation NGH reservoir exists from 136.4 to 174.4 m below the seafloor (mbsf), with a water depth of 1273.6 m. The lithology of the hydrate-bearing sediments is mainly silty clay and clay silt with a porosity of 0.5 and an absolute permeability of 10 mD. The clay content ranges from 17.2% to 44.2%, and the silt content ranges from 55.6% to 80.1%. The underlying free gas layer is distributed at 174.4-193.9 mbsf with relatively low absolute permeability (average 2 mD). This reservoir is a typical Class 1 hydrate reservoir. In situ measurements show that the temperature of the seafloor is approximately 4°C. The wet thermal conductivity and dry thermal conductivity of the deposits are 2.917 W/m/K and

![FIGURE 1 Sketch map of (A) the location of site W19 in the South China Sea and (B) the target reservoir conditions of site W19 (Gas & water in the figure means the underlying free gas layer)](image-url)
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1.0 W/m/K, respectively. As a special type of Class 1 hydrate reservoir, this reservoir has an overburden (OB) and underburden (UB) that are fully saturated with water, and their absolute permeabilities are both 1.16 mD. The hydrate saturation estimation based on well logging is shown in Figure 2. The highest hydrate saturation can reach 55.6%. To better determine the influences of gas saturation and permeability on gas recovery, the weighted average value for the whole hydrate reservoir (24.36%) is adopted in this study. The main modelling reservoir parameters and physical properties are summarized in Table 1.

Because the permeability of the studied hydrate accumulation is relatively low, so the production capacity of single vertical well may be limited. Yu et al.23 suggested that the utilization of multiple-well system helps to enhance gas recovery in the low-permeability hydrate reservoirs. Thus, the purpose of this investigation is mainly to analyze the production performance from a single-well, which is as a part of a multiple-well system involving vertical wells installed on a regular areal pattern (Figure 2). An axisymmetric cylindrical hydrate reservoir model with a radius of \( r = 200 \) m and a thickness of 393.9 m is employed for the numerical simulations. Specifically, the thickness of the OB is 136.4 m, which is extended to the ocean floor. The UB extends to a sufficiently large depth (i.e., the thickness of 200 m is adopted in this investigation after computation trial), which can ensure that the pressure and temperature of the bottom boundary do not change during the simulation. The top and bottom boundaries are treated as flowing boundaries that can replenish water removed within the hydrate-bearing system. The well is located in the center of the simulation reservoir, with a radius of \( r_w = 0.1 \) m, and the perforated interval extends from the hydrate formation to the free gas layer, with a length of 57.5 m.

The cylindrical reservoir model is discretized into 90 (\( r \)-coordinate) \( \times \) 326 (\( z \)-coordinate) grid blocks, with a total number of 29,340 grids. A total of 180 inactive elements are assigned as boundary cells located in the uppermost and lowermost grids of the OB and UB, respectively. The corresponding temperatures and pressures of the inactive cells (i.e., the uppermost and lowermost grid block layers in the TOUGH+HYDRATE software) remain constant during the simulation. Along the radial direction, the computational domain is divided nonuniformly. There are 45 meshes discretized in the radial range of 20 m, and the minimum size in the vicinity of production well is 0.1 m. Meanwhile, the grids in the hydrate and gas layers are also finely divided due to the significant heat and mass transfers in this region while the discretization in underburden is gradually enlarged with depth. That is, fine discretization (\( \Delta Z = 0.1-0.5 \) m) is applied in the gas hydrate-bearing sediments (GHBS) and the gas layer, and coarser blocks (\( \Delta Z > 0.5 \) m) are adopted in the other domains far from the reservoirs in the perpendicular direction.66 The uppermost and bottommost of the model are set to be very thin (\( \Delta Z = 0.001 \) m), ensuring correct gradients.

FIGURE 2 Schematic diagram of the multiple-well system, Class 1 hydrate reservoir model and hydrate saturation65
and true boundary behavior. Additionally, it is assumed that no flow occurs across the outermost lateral boundary.

### 2.2 Initial conditions

The initialization process of our simulations is performed using the method suggested by Moridis et al. In this special Class 1 hydrate reservoir, the numerical domain is subdivided into two subdomains: (a) a subdomain comprising the top boundary, the overburden, and GHBS, including the thin element containing the base of GHBS (where gas, water, and hydrate coexist), and (b) a subdomain comprising the thin element containing the base of GHBS, the gas layer, the underburden and the bottom boundary. The domain (a) is initialized using the known hydrate saturation, the known pressure and temperature at the top and bottom of the above subdomain. The similar process is repeated with the lower subdomain (b). Then, slightly adjust the temperature of the bottom boundary until the heat flows in the two subdomains are identical. Finally, the initial condition of the entire system is checked through numerical simulation without any mass extraction by TOUGH+HYDRATE software. After that, the correct initial conditions can be obtained, as shown in Figure 3.

#### TABLE 1 Main properties and boundary conditions of the hydrate reservoir model

| Parameter                           | Value                  | Parameter                           | Value                  |
|-------------------------------------|------------------------|-------------------------------------|------------------------|
| Hydrate zone thickness              | 38 m                   | Porosity $\phi_1$ (overburden)      | 0.60                   |
| Gas layer                           | 19.5 m                 | Porosity $\phi_2$ (underburden)     | 0.51                   |
| Overburden thicknesses              | 136.4 m                | Porosity $\phi_3$ (hydrate zone and gas layer) | 0.50                   |
| Underburden thicknesses             | 30 m                   | Water salinity                      | 0.035                  |
| Hydrate saturation                  | 24.36 %                | Gas composition                     | 100% CH$_4$            |
| Gas saturation                      | 5.24 % (average value) | Radius of the simulation domain     | 200 m                  |
| Absolute permeabilities of hydrate zone | $k_l = k_z = 1.00 \times 10^{-14}$ m$^2$ (10 mD) | Compressibility                   | $1.00 \times 10^{-8}$ Pa$^{-1}$ |
| Absolute permeabilities of gas layer | $k_l = k_z = 2.00 \times 10^{-15}$ m$^2$ (2 mD) | Initial bottom pressure of gas hydrate-bearing sediments ($P_B$) | $1.480 \times 10^7$ Pa |
| Absolute permeabilities of the overburden and underburden | $k_l = k_z = 1.16 \times 10^{-15}$ m$^2$ (1.16 mD) | Initial bottom temperature of gas hydrate-bearing sediments ($T_B$) | 14.44 °C |
| Grain density $\rho_R$ (all formations) | 2700 kg/m$^3$              | Pressure at well $P_w$                | $4.5 \times 10^6$ Pa    |
| Geothermal gradient                 | 60 K/km                | $S_{\mu A}$                         | 0.5                    |
| Grain specific heat                 | 1000 J kg$^{-1}$ °C$^{-1}$ | $S_{\mu G}$                         | 0.05                   |
| Compression coefficient             | $1.00 \times 10^{-8}$ Pa$^{-1}$ | $n$                                 | 5                      |
| Dry thermal conductivity $K_{GRD}$  | 1.0 W/m/K              | $n_G$                               | 3                      |
| Wet thermal conductivity $K_{GRW}$  | 2.917 W/m/K            | Capillary pressure model            | $P_{cap} = -P_0 \left[ (S^*)^{-1/4} - 1 \right]^{1.5}$ |
| Relative permeability model$^{53}$ | $K_A = (S_A)^\alpha K_G = (S_G)^\alpha$ | $S^* = (S_A - S_{AA}) / (1 - S_{AA})$ |
|                                     | $S_A^* = (S_A - S_{AA}) / (1 - S_{AA})$ | $S_G^* = (S_G - S_{AG}) / (1 - S_{AG})$ |

**FIGURE 3** Initial conditions of the simulated reservoir
In particular, the pore pressure at the bottom of GHBS is 14.80 MPa. According to the hydrate pressure-temperature equilibrium curve, the corresponding phase equilibrium temperature is approximately 14.54°C. Compared with the in situ temperature measurement (14.44°C), the initial condition verifies the stability of gas hydrates in the formation.

In previous studies, a constant well pressure was recommended for gas production from Class 1 deposits. According to the offshore field production tests performed in China and Japan, gas recovery induced by depressurization with a constant pressure of 4.5 MPa is employed in the reference case. Darcian flow through a pseudo-medium in the interior of the well is used to describe the borehole flow. This pseudo-medium has a very high permeability ($k_r = k_z = 5.0 \times 10^{-9} \text{ m}^2$), with a porosity of 1.0 and a capillary pressure of 0 MPa.

### 3 SIMULATION RESULTS AND SENSITIVITY ANALYSIS

#### 3.1 Gas production from Class 1 hydrate reservoirs with different initial gas saturations

The initial gas saturation of the underlying free gas layer at site W19 is estimated to be 0%-16.9% (Figure 2), with an average of 5.24%. Due to the special characteristics of Class 1 hydrate accumulation and measurement limitations, there may be some differences in gas saturation obtained by well logging. Therefore, in this section, the effect of free gas saturation on gas production from Class 1 hydrate reservoirs within 5 years is first investigated. The gas saturation is set between 3.24% and 11.24% according to the preliminary geological data at site W19 (Table 2).

##### 3.1.1 Gas and water production

The volumetric rates of gas production ($Q_g$) in Cases 1-5 are shown in Figure 4A. In the early period, the $Q_g$ is very prominent because of the high-pressure difference between the production well and the reservoir, which can cause rapid hydrate dissociation and free gas recovery around the wellbore. As production proceeds, the pressure gradient between the dissociation front and the production well gradually decreases, resulting in a decrease in $Q_g$. In addition, the underlying free gas saturation near the wellbore also decreases with continuous depressurization. According to the simulations, the $Q_g$ in Case 5 (i.e., $S_{gas} = 11.24\%$) is markedly higher than that in Case 1 (i.e., $S_{gas} = 3.24\%$) or Case 2 (i.e., $S_{gas} = 5.24\%$). The higher initial free gas saturation contributes to a higher $Q_g$, whereas a Class 1 reservoir with relatively low gas saturation (below 5.24%) has no distinct influence on gas recovery. The possible reason is that the irreducible gas saturation is set to 5% ($S_{irG} = 0.05$) in the simulation (Table 1). Hence, there is no obvious variation in gas production if the initial free gas saturation is lower than or close to 5%. In contrast, a high initial free gas saturation (>5%) boosts gas production significantly. However, the largest $Q_g$ in Case 5 during the 5 years of production are mainly between 900 m$^3$/d and 2400 m$^3$/d, which are far below the commercial production level.

As shown in Figure 4A, the volumetric rate of water production in the well ($Q_w$) is found to decrease initially and then increase gradually throughout the later simulation. At the early stage, $Q_w$ decreases mainly because the initial pressure...
FIGURE 5  Spatial distributions of (A) P, (B) T, (C) S_{hyd}, (D) S_{gas}, and (E) S_{aqu} at t = 1800 days under conditions of different initial gas saturations (In order to clearly present the physical distributions of the hydrate-bearing layer and gas layer, only 100 m of the underburden is shown, the same below)
gradient near the wellbore gradually decreases. However, the fluid resulting from the permeable burdens can invade the GHBS as the pressure drop gradually expands. Meanwhile, both water released from hydrate dissociation and the reduction in free gas around the well may also promote water extraction (Figure 5E). In addition, an increase in the underlying free gas saturation significantly affects the water extraction. The $Q_w$ values in Cases 1-2 (i.e., $S_{gas} < 5.24\%$) are higher than those in Cases 3-5. It is easy to understand that initial high water saturation in the gas formation can give rise to a high water production rate. Furthermore, each phase migration can also be disturbed by the other phase(s) in multiphase flow. Therefore, an increase in free gas saturation helps to decrease water extraction.

The gas-to-water ratio ($R_{gw} = \frac{V_g}{V_w}$) is a relative criterion for evaluating the production efficiency from methane hydrate reservoirs and is mainly used to economically assess production potential. As shown in Figure 4B, $R_{gw}$ is relatively high at the beginning since a large amount of free gas is extracted. However, the free gas near the well gradually decreases and the water from the permeable burdens gradually flows into the production well, which are adverse to increasing the production efficiency. It can be observed that $R_{gw}$ increases with increasing gas saturation, especially under high initial free gas saturations (i.e., Cases 3-5).

In addition, an increase in the gas saturation may cause a decrease in the hydrate dissociation ratio ($R_d$) of the whole simulation system (Figure 4B). The possible reason is that secondary hydrates may form near the hydrate-gas interface and at the hydrate dissociation front during gas recovery. Clearly, high free gas saturation in the gas layer is favorable for the formation of secondary hydrates (Figure 5C). Presumably, because the secondary hydrate formation rate is faster than the hydrate dissociation rate in the early period, the whole system shows no hydrate dissociation and even a negative value at the beginning. The higher the initial free gas saturation is, the more secondary hydrate forms. Therefore, the initial dissociation time of the whole system seems to be late with an increase in the free gas saturation.

### 3.1.2 Spatial distributions of physical properties

To visually determine the differences among Cases 1-5, the final spatial distributions of the physical properties are shown in Figure 5. Because this study mostly considers the main factors affecting production potential, specific analyses of the evolution processes are not emphasized here.

1. **Spatial distribution of pressure ($P$)**

As shown in Figure 5A, a significant pressure reduction can be observed in the surrounding sediments. However, the evident pressure-drop areas in all cases are only within the range of 35 m near the well because of the extremely low absolute permeability of the reservoir. These results demonstrate the above analysis of low gas production over 5 years, as shown in Figure 4A. In addition, the affected area caused by depressurization near the hydrate-gas interface narrows with an increase in the initial gas saturation. The possible reason is that more free gas can invade the GHBS because of buoyancy if the initial gas saturation increases, which inhibits pressure reduction near this interface, especially at high gas saturation. Meanwhile, the pressure-drop area in the OB can expand when the initial gas saturation increases. This phenomenon occurs probably because the underlying free gas enters the GHBS and forms secondary hydrates, which sharply decreases the effective permeability of the GHBS and results in better pressure-drop transfer in the OB.

### 2. Spatial distribution of temperature ($T$)

The temperature “subsidence” in the upper dissociation front is notable because of the endothermic reaction caused by hydrate dissociation (Figure 5B). It is clear that the isotherms move upward and merge in the vicinity of the production well, especially at the bottom of the perforated interval. This result occurs because the high-temperature fluid in the permeable UB enters the production well, counteracting the temperature decrease caused by hydrate dissociation. In addition, the isotherms in the simulated formation with higher initial gas saturation move upward more obviously than those in formations with lower gas saturation. The possible reason is that the underlying free gas with a relatively high temperature invades the hydrate reservoir due to buoyancy (Figure 5D). Meanwhile, some

### TABLE 3 Numerical simulations of reservoirs with different permeabilities and low gas saturations

| Case | $k_x$ | $k_z$ | $r_{xz}$ | $k_x$ | $k_z$ | $r_{xz}$ |
|------|------|------|--------|------|------|--------|
| Case 2 | 10  | 10  | 1      | 2    | 2    | 1      |
| Case 6 | 50  | 50  | 1      | 2    | 2    | 1      |
| Case 7 | 100 | 100 | 1      | 2    | 2    | 1      |
| Case 8 | 50  | 10  | 5      | 2    | 2    | 1      |
| Case 9 | 100 | 10  | 10     | 2    | 2    | 1      |
| Case 10 | 10  | 10  | 1      | 10   | 10   | 1      |
| Case 11 | 10  | 10  | 1      | 20   | 20   | 1      |
| Case 12 | 10  | 10  | 1      | 10   | 2    | 5      |
| Case 13 | 10  | 10  | 1      | 20   | 2    | 10     |

Note: $r_{xz}$ = the horizontal permeability $k_x$, the vertical permeability $k_z$ (the same below).
free gas may form secondary hydrates under proper pressure and temperature (Figure 5C), releasing some heat in these areas.

3. Spatial distribution of hydrate saturation ($S_{\text{hyd}}$)

The $S_{\text{hyd}}$ distributions in Cases 1-5 indicate that the hydrate dissociation front presents a nearly well-regulated shape (Figure 5C). The differences in the full hydrate dissociation area are negligible, regardless of the initial gas saturation. This result can be attributed to the same initial conditions in the whole simulation system except for the slight gas saturation difference in the underlying free gas layer. Therefore, it is speculated that the gas recovery rate may be significantly affected by free gas saturation (Figure 4A). Moreover, the dissociation front in the lower part of the hydrate reservoir is horizontally deeper than that in the upper part. This situation is mainly caused by the upward migration of fluids (i.e., free gas and water) with high temperature (Figure 5B), which accelerates the hydrate dissociation. In addition, small amounts of secondary hydrates can be observed in the upper part of the dissociation front. The temperature and salinity in the dissociation front dramatically decrease because of the endothermic nature and dilution effect of hydrate dissociation, which are conducive to forming secondary hydrates if some free gas released from hydrate migrates upward after depressurization. Furthermore, high gas saturation, that is, higher than 9.24%, hinders hydrate dissociation and forms secondary hydrates at the hydrate-gas interface. The main reason is that the underlying free gas can enter the GHBS because of buoyancy and form hydrates near this region, which is located in the hydrate stability area. In contrast, the $S_{\text{hyd}}$ distribution changes slightly if the gas saturation decreases to below 5.24%, which can also demonstrate a result similar to that shown in Figure 4.

4. Spatial distribution of gas saturation ($S_{\text{gas}}$)

Figure 5D shows the final spatial distributions of $S_{\text{gas}}$ under different cases. The highly saturated free gas is

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**TABLE 4** Numerical simulations of reservoirs with different permeabilities and high gas saturations

| Case   | $k_r$ | $k_z$ | $r_{xz}$ | $k_r$ | $k_z$ | $r_{xz}$ |
|--------|-------|-------|----------|-------|-------|----------|
| Case 4 | 10    | 10    | 1        | 2     | 2     | 1        |
| Case 14| 50    | 50    | 1        | 2     | 2     | 1        |
| Case 15| 100   | 100   | 1        | 2     | 2     | 1        |
| Case 16| 50    | 10    | 5        | 2     | 2     | 1        |
| Case 17| 100   | 10    | 10       | 2     | 2     | 1        |
| Case 18| 10    | 10    | 1        | 10    | 10    | 1        |
| Case 19| 10    | 10    | 1        | 20    | 20    | 1        |
| Case 20| 10    | 10    | 1        | 10    | 2     | 5        |
| Case 21| 10    | 10    | 1        | 20    | 2     | 10       |

**FIGURE 6** Evolutions of (A) $Q_g$, (B) $Q_w$ and (C) $R_{gw}$ under conditions of different permeabilities in the hydrate reservoir
mainly distributed in the vicinity of the production well. This phenomenon occurs mainly because both the gas released from hydrate dissociation and the underlying free gas accumulate near the wellbore under differential pressure. It can also be found that free gas near the borehole is preferentially extracted because of the high-pressure gradient in this area. Meanwhile, in Cases 4 and 5, high gas concentrations can be observed around the hydrate-gas interface. The possible reason is that secondary hydrate formation decreases the effective permeability, which obstructs the upward migration of underlying free gas. When the underlying free gas saturation increases, the gathering extent below the hydrate-gas interface becomes more obvious due to the buoyancy (i.e., Cases 3-5). In contrast, the phenomenon cannot be detected when the underlying free gas layer has low initial free gas saturation. This is mainly because little gas can escape, especially when the free gas saturation is less than 5%.

5. Spatial distributions of water saturation ($S_{\text{aqu}}$)

The $S_{\text{aqu}}$ distribution in the simulation system at $t = 1800$ days is shown in Figure 5E. Because the water saturation is dependent on the hydrate and free gas distributions, an obvious vertical low water saturation zone at the dissociation front can be observed. That is, abundant free gas gathers around this area, and some secondary hydrates form at the same time. Similarly, high gas saturation in the underlying free gas layer is conducive to gas migration and secondary hydrate formation, resulting in a low water saturation region near the hydrate-gas interface. For the same reason mentioned above, the higher the free gas saturation is, the lower the water saturation presents at the hydrate-gas interface.

3.2 Effect of permeability on gas production

3.2.1 Permeability setting in the reservoir with different gas saturations

Based on the predictions, the $R_d$ values of Cases 1-5 are less than 1.25% within 5 years of production, which means that hydrate dissociation is quite limited (Figure 4B). In addition, the hydrate dissociation and gas production potential can be dramatically affected by the underlying free gas saturation (Figures 4 and 5). Therefore, the initial gas saturation should be considered a key sensitive parameter in productivity evaluation.

As mentioned above, a Class 1 hydrate reservoir with gas saturation below 5.24% has no distinct influence on gas recovery. The higher initial gas saturation contributes to a higher $Q_g$, while gas saturation higher than 9.24% hinders hydrate dissociation and forms secondary hydrates at the hydrate-gas interface. Thus, gas layer with two typical initial
gas saturations (5.24% and 9.24%) are mainly studied in this section, representing a GHBS with relatively low and high initial gas saturation, respectively.

Cases 6-21 are designed to investigate the effect of permeability enhancement on gas recovery (e.g., improving absolute isotropic permeability and anisotropic permeability) from GHBS with different initial gas saturations for a production period of 5 years (Tables 3 and 4). According to previous investigations, the ratios of horizontal permeability to vertical permeability in most reservoirs generally range between 2 and 10. Therefore, we specify different values of $r_{zz}$ for the reservoir (i.e., $r_{zz} = 1, 5$ and 10) in our modelling to analyze the effect of permeability anisotropy on gas production, which are consistent to the field permeability anisotropy values obtained from laboratory tests and the general assumptions adopted in most numerical simulations.

Consequently, the absolute isotropic/anisotropic permeability of the hydrate layer ranges from 10 mD to 100 mD, and the absolute isotropic/anisotropic permeability of the gas layer is mainly between 2 mD and 20 mD. Case 2 and Case 4 are preferred as the corresponding reference cases. The absolute index (i.e., production potential) and relative criterion (i.e., $R_{gw}$) for evaluating the efficiency of gas production are presented in the following sections.

### 3.2.2 | The reservoir with low gas saturation

**Permeability enhancement in hydrate-bearing sediments**

As shown in Figure 6A, the $Q_g$ at the beginning is very high, and it then gradually decreases as the depressurization range expands. The gas released from the hydrate reservoir increases with increasing permeability, including isotropic permeability and anisotropic permeability. However, the effect of permeability anisotropy (i.e., different $r_{zz}$) on gas production is not obvious within 5 years. When the other parameters remain constant, increasing the permeability of the hydrate reservoir significantly enhances production behavior because of the better migration channels and depressurization effect. It is clear that the hydrate dissociation extent is more significant in the high-permeability reservoirs, enhancing gas production (e.g., Case 7 and Case 9) (Figure 7A), which has also been reported by some previous studies. Simultaneously, the permeability enhancement in the hydrate reservoir expands the scope of high gas saturation around the well, and increasing the vertical permeability is more significant (Figure 7B). This result occurs mainly because the free gas from the gas layer or hydrate dissociation moves up more smoothly and accumulates below the low-permeability OB. The secondary hydrate formation under the interface between the GHBS and OB becomes more extensive and obvious in Case 7 and Case 9. Comparatively, the increasing gas production potential is mainly derived from the gas hydrate dissociation and some free gas escape from the underlying gas layer.

In addition, it is anticipated that increasing the permeability, including anisotropic and isotropic permeability, will...
increase the water production from the whole system, but the effect of the anisotropy on water production is limited. As shown in Figure 6B, higher permeability facilitates water extraction, which is mainly attributed to fast hydrate dissociation and water migration. In comparison, the gas production improvement multiple at the initial stage is lower than that of water extraction, so all the $R_{gw}$ values in Cases 6-9 are lower than that in Case 2 at the beginning (Figure 6C). However, the opposite results can be observed because of the contrast in the increasing trends of gas and water production. The results also show that the horizontal permeability of the GHBS is the main factor affecting gas recovery. As shown in Figure 6C, anisotropic permeability enhancement is more helpful for gas recovery from the GHBS with high permeability in the late stage. This outcome is consistent with the gas production behavior predicted in a low-permeability Class III hydrate reservoir. Therefore, increasing horizontal permeability as much as possible may lead to better gas production performance during long-term production.

**Permeability enhancement in the underlying gas layer**

Clearly, more free gas can be extracted with an increase in the permeability of the underlying gas layer even though the gas saturation is relatively low (i.e., 5.24%) (Figure 8A). As shown in Figure 9B, relatively high gas saturation can be observed near the wellbore with an increase in the permeability of the underlying gas layer, which demonstrates that more free gas can be trapped in Cases 10-13 than in Case 2. According to the spatial distributions of $S_{hyd}$ and $S_{gas}$ at $t = 1800$ days in the whole simulation system (Figure 9), the increase in $Q_g$ is mainly due to the increased free gas production from the underlying gas layer rather than from hydrate dissociation. In all cases, the hydrate dissociation area and the distribution of secondary hydrate formation are almost the same (Figure 9A). In addition, the free gas layer permeability isotropy and anisotropy have negligible effects on gas production mainly because the permeability...
of GHBS is relatively low and the increase in vertical permeability in the low-saturated gas layer has little impact on pressure reduction in the GHBS. Meanwhile, the gas extraction is mainly from the horizontal direction rather than the vertical direction. Hence, there is no significant difference in the evolution trend.

In addition, permeability enhancement can increase water production from gas formation (Figure 8B). The greater the permeability enhancement is, especially the higher the isotropic permeability, the more water produced from the gas layer due to the better migration channels. Clearly, water extraction can be stimulated when permeability increases in all directions. As a result, improving the permeability of the gas layer with low initial gas saturation cannot effectively enhance $R_{gw}$ (Figure 8C). The analogous results are very similar to the prediction by Sun.65 Meanwhile, the permeability anisotropy can increase $R_{gw}$ to some extent. The possible reason is that a decrease in the vertical permeability of the gas layer can prevent water extracted from the permeable UB.

Quantitative comparison of production behaviors
As mentioned above, permeability enhancement in either the GHBS or the underlying gas layer is beneficial to increase $Q_g$ and $Q_w$ within 5 years of production (Figures 6 and 8). However, permeability improvement in the gas layer is unfavorable for increasing the gas-to-water ratio. Similarly, an increase in the permeability of the GHBS cannot increase $R_{gw}$ in the early stage. Furthermore, the higher the horizontal permeability is, the better the production situation during long-term production will be.

In this section, we select the average production index values and proportion of the amount of water replenished by inflows from overlying and underlying sediments to total water production volume (PWIT) in Cases 2 and 6-13 within 5 years for the comprehensive comparison of production behaviors caused by different permeabilities in the Class 1 hydrate reservoir. As shown in Figure 10, the permeability enhancement in the GHBS shows better production performance even though the water extraction increases at the same time. Additionally, increasing the permeability of the underlying free gas layer can help to stimulate gas recovery, but the effect is not significant. Here, Case 2 is selected as a represented case to show the evolution of water flows at key interfaces because the similar prediction results are obtained from other cases. As shown in Figure S1A, water inflows at the top of the GHBS are larger than that at the bottom of the gas layer. The possible reasons are that gravity facilitates the downward flow of formation water and the effective permeability of GHBS is relatively high, thereby increasing water extraction from the permeable OB. It is obvious that the amount of water inflows at the top of the GHBS and the bottom of the gas layer is less than the total water production volume. Compared with Case 2, the PWIT is decreased when the permeability of GHBS is enhanced among Cases 6-9 (Figure S1B). Meanwhile, anisotropic permeability may slightly contribute to gas production. For example, the average $R_{gw}$ in Case 2 (5.9 ST m$^3$ CH$_4$/m$^3$ of H$_2$O) is enhanced to approximately 6.78ST m$^3$ CH$_4$/m$^3$ of
H₂O in Case 9 (Figure 10). The average $Q_g$ can increase by a factor of six when the horizontal permeability of the reservoir increases by tenfold. Moreover, anisotropic permeability may also slightly affect the PAWI (Figure S1B). In summary, high permeability in hydrate formation, especially a higher horizontal permeability, can contribute to the improvement of gas production from a Class 1 hydrate reservoir with low initial gas saturation.

### 3.2.3 The reservoir with high gas saturation

**Permeability enhancement in the hydrate-bearing formation**

As shown in Figure 11A, the gas production rate can be stimulated in a hydrate reservoir with high absolute permeability when the gas saturation is relatively high (i.e., 9.24%). This result occurs mainly because increasing the permeability of the hydrate formation contributes to depressurization and accelerates hydrate dissociation. These processes can be directly demonstrated by the spatial distribution of hydrate saturation. According to Figure 12A, the full dissociation area around the wellbore is expanded due to the high reservoir permeability. However, the increase in the hydrate reservoir permeability is also conducive to gas escape from the gas layer due to buoyancy (Figure 12B), so secondary hydrates form at the top of the GHBS because of the blocking effect caused by the low-permeability OB (Figure 12A).

Similarly, high reservoir permeability promotes water production from the GHBS caused by better migration channels and more water released from hydrate dissociation (Figure 11B). Meanwhile, the decreasing gas saturation in the gas layer during production is also beneficial for water flowing from the underlying formations, thereby increasing water extraction in Cases 14-17 (Figure 12B). Comparatively, the $R_{gw}$ in the low-permeability hydrate reservoir is relatively high in the early period, but the situation reverses during long-term production (Figure 11C). A possible reason is that the water in the permeability-enhanced hydrate reservoir is easier to extract in the early stage, and the gas extraction extent is relatively low, resulting in a decrease in $R_{gw}$. As production proceeds, the increase in gas recovery is greater than that of water extraction. Therefore, the $R_{gw}$ curves in Cases 14-17 gradually exceed those in Case 4. This finding demonstrates that high permeability in the hydrate reservoir is important for economic exploitation.

Meanwhile, the permeability anisotropy significantly affects gas production within 5 years (Figure 11A). Gas production from the GHBS with anisotropic permeability is higher than that from the GHBS with isotropic permeability. The larger the horizontal permeability is, the more significant the difference is. The reason for this phenomenon is that permeability anisotropy in the GHBS can effectively prevent the fluid from flowing along the vertical direction and thus increases depressurization effect and hydrate dissociation along the horizontal direction. As shown in Figure 12A, the formation of secondary hydrates in the middle of the GHBS...
in Cases 14-15 may also inhibit fluid flow, thereby decreasing gas production to some extent. However, the water production performance in Case 17 is not significantly different from that in Case 15 (Figure 11B). A possible reason is that the viscosities of methane and water are obviously different. It can be speculated that water production from the Class 1 hydrate reservoir may not be significantly influenced by permeability anisotropy due to its relatively high viscosity. In summary, anisotropic permeability enhancement in the GHBS is more helpful for gas recovery stimulation for long-term production, and the larger the anisotropic permeability value, the earlier the effectiveness is achieved.

Permeability enhancement in the underlying gas layer
Similarly, the effect of permeability enhancement in the gas layer with high gas saturation on production behaviors is also discussed. The permeability enhancement in the gas layer can increase the gas production rate (Figure 13A). Meanwhile, its increase is also beneficial to water extraction to some extent because of the better transport channels, but the yield-promoting effect seems to be limited (Figure 13B). Consequently, the corresponding gas production efficiency (i.e., $R_{gw}$) improves with an increase in the permeability of gas layer (Figure 13C).

Gas recovery is facilitated if the anisotropic permeability is considered and the other parameters remain constant (Figure 13). The larger the horizontal permeability is, the greater the difference will be. In addition, the formation of secondary hydrates at the dissociation front and the interface between the gas and hydrate zones can be observed. It is clear that the formation of secondary hydrates at the interface decreases since the upward free gas migration into the GHBS is prohibited by the low vertical permeability in the gas layer (Figure 14). Meanwhile, the water recovery from the GHBS and the gas layer also decreases because the water extracted from the UB is impeded (Figure 13B). Hence, we can conclude that increasing the permeability of the underlying free gas formation with high saturation, especially the horizontal permeability, may increase gas production efficiency within several years, while the advantage may gradually disappear later.

Quantitative comparison of production behaviors
Similarly, for Class 1 hydrate reservoir with high gas saturation, increasing the permeability of the GHBS or the underlying gas layer favors fluid extraction and gas recovery. Compared with the situation of isotropic permeability, higher horizontal permeability is more favorable for decreasing $Q_w$ and improving $Q_g$ and $R_{gw}$. However, high permeability in the GHBS is not conducive to improving the $R_{gw}$ during the early period.

Here, we also select the average values and PWIT in Case 4 and Cases 14-21 after 5 years of production for the comprehensive comparison. As shown in Figure 15, the average $Q_g$ and $Q_w$ in Cases 14-17 can significantly increase, suggesting that higher permeability in the GHBS is favorable for boosting hydrate dissociation and fluid extraction. Specifically, the average $Q_g$ in Case 17 increases from 1100 to 7290 m$^3$/d when the reservoir permeability increases tenfold. Moreover,
the PWIT significantly decreases when the permeability of GHBS is enhanced (Figure S1B). However, from the perspective of the average $R_{gw}$, the high permeability of the GHBS is not all conducive to improving the $R_{gw}$. It should be noted that permeability anisotropy (i.e., $r_{rz} = k_r/k_z$) may significantly affect $R_{gw}$ and increase the production efficiency if $r_{rz}$ is higher than 10. This phenomenon is very obvious under the condition that the permeability of the gas layer increases, which shows better performance than those in Cases 14-17. The $R_{gw}$ in Case 21 is 12.6 ST m$^3$ CH$_4$/m$^3$ H$_2$O, which is the maximum among Cases 14-21. However, the PWIT significantly decreases when the horizontal permeability of the gas layer in Case 21 is increased (Figure S1B). In summary, high-permeability anisotropy ($r_{rz} > 10$) in a Class 1 hydrate reservoir with high initial gas saturation is beneficial to enhance long-term gas production performance.

3.3 | Effect of permeability enhancement on secondary hydrate formation and hydrate dissociation

The formation of secondary hydrates is a self-reinforcing process. The greatest obstacle during the production process is the reduction in reservoir permeability and even clogging. As shown in the above hydrate distribution profiles (i.e., Figures 5, 7, 9, 12, 14), secondary hydrates form at the hydrate dissociation front and/or the hydrate-gas interface, which is mainly dependent on reservoir conditions, such as different gas saturation (e.g., Case 2 and Case 4) and permeability (e.g., Case 4 and Case 15). Clarifying the relationship between gas production and secondary hydrate formation can optimize sustainable gas production strategies. At present, secondary hydrate formation is generally qualitatively identified by the spatial distribution of hydrate saturation. Few
studies have been conducted to quantitatively analyze the effect of secondary hydrate formation on the hydrate dissociation process and gas production performance. Therefore, in this section, the secondary hydrate volume is quantitatively calculated after 5 years of depressurization-induced production in the Class 1 hydrate reservoir, and the discrepancy between the actual methane hydrate dissociation ratio ($R^*_D$) and the ostensible hydrate dissociation rate ($R_D$) of the whole system is presented and discussed. Additionally, the correlation between the hydrate dissociation ratio ($R^*_D$ and $R_D$) and gas production rate is analyzed.

### 3.3.1 Secondary hydrate formation volume calculation and hydrate dissociation ratio discrepancy

The formation of secondary hydrates in the GHBS is depicted by a higher $S_{hyd}$. To obtain the hydrate amount marked in the red zone in different cases, two methods (i.e., the average hydrate saturation multiplied by marked pore volume and the accumulation of actual hydrate saturation of each mesh multiplied by its pore volume) are proposed and compared. According to the calculation results, deviations among them are mainly between 0.19% and 1.06% in different cases, within the allowable error range. For the convenience of rapid computing, the amount of secondary hydrate formation ($V_3$) and the $R_D$ can be separately calculated based on the following formulas:

\[
V_3 = V_1 - V_2
\]  
\[
R_D = \frac{(V_4 - V_3)}{V_5}
\]

where $V_1$ is the total gas hydrate amount in the marked red zone; $V_2$ is the corresponding amount of the undissociated gas hydrate in this area, which can be calculated by the above-mentioned average hydrate method; $V_4$ is the actual amount of gas hydrate dissociation; and $V_5$ is the initial total amount of gas hydrate in the GHBS. After calculation, the $V_3$ values in all cases are presented in Table 5. The discrepancy between $R^*_D$ and $R_D$ is presented in Figure 16.

As shown in Table 5, increasing the permeability of the GHBS or free gas layer in the low initial gas saturation significantly increases secondary hydrate formation in the GHBS. It is clear that the higher the permeability of the GHBS or the free gas layer, the more secondary hydrates form, and permeability anisotropy (i.e., $r_{zz} > 1$) can contribute to their formation. In comparison, permeability enhancement in the corresponding gas layer has less effect on the formation of secondary hydrates (Figure 9). However, the evolution trend under the high initial gas saturation
condition is quite different. If the formation permeability is isotropic, increasing its value accelerates secondary hydrate formation. When permeability anisotropy (i.e., $r_{zz} > 1$) is considered, the results are quite different. That is, some conditions may help to form secondary hydrates, and some situations may inhibit hydrate formation. Therefore, the influence of anisotropic permeability on secondary hydrate formation is extremely evident.

Figure 16 shows the difference between the $R^*_D$ and $R_D$ within 5 years in different cases. For the Class 1 hydrate reservoir with low initial gas saturation, the impact of secondary hydrate formation on the hydrate dissociation ratio is obvious once the permeability of the GHBS increases by more than 5 times, while the permeability of the free gas layer shows a negligible effect (Figure 16A). It is clear that the secondary hydrate formation in Case 9 significantly affects the hydrate dissociation rate (i.e., $R^*_D$ and $R_D$). The $R^*_D$ is enhanced from 1.25 in Case 2 to 14.83 in Case 9 with increasing horizontal permeability, and the discrepancy between $R^*_D$ and $R_D$ is 2.15. Meanwhile, for the Class 1 hydrate reservoir with high initial gas saturation, the influence of secondary hydrate formation on the hydrate dissociation ratio is significant (Figure 16B). It can be found that secondary hydrate formation results in a smaller $R_D$. This situation means that secondary hydrate formation decreases the production performance in such reservoirs. Comparatively, the secondary hydrate amount in Case 15 is the largest, and its impact on the hydrate dissociation rate ($R^*_D$ and $R_D$) is most distinct. The corresponding difference between $R^*_D$ and $R_D$ is 2.32. This phenomenon mainly occurs because increasing isotropic permeability significantly helps to form secondary hydrates in the GHBS.

### 3.3.2 Relationship between the hydrate dissociation ratio and the gas production rate

The relationship between the hydrate dissociation ratio ($R^*_D$ and $R_D$) and the average gas production rate within 5 years is determined by the use of Spearman’s rank correlation coefficients.77 As shown in Table 6, $R^*_D$ and $R_D$ are highly correlated with the gas production rate in different cases. This

| Correlation | Gas production rate in the Class 1 hydrate reservoir with low initial gas saturation | Gas production rate in the Class 1 hydrate reservoir with high initial gas saturation |
|-------------|----------------------------------------------------------------------------------|---------------------------------------------------------------------------------|
| $R^*_D$     | 0.979                                                                            | 0.983                                                                           |
| $R_D$       | 0.979                                                                            | 0.967                                                                           |

### Table 7 Numerical simulations of reservoirs with different permeabilities and gas saturations

| Gas saturation | Case   | The permeability of hydrate formation (mD) | The permeability of gas layer (mD) |
|----------------|--------|-------------------------------------------|-----------------------------------|
|                |        | $k_r$ $k_z$ $r_{zz}$ $k_{r,z}$ $r_{zz}$ | $k_r$ $k_z$ $r_{zz}$               |
| 5.24%          | Case 22| 10 10 1                                  | 2 2 1                             |
|                | Case 23| 50 50 1                                  | 2 2 1                             |
|                | Case 24| 100 100 1                                | 2 2 1                             |
|                | Case 25| 50 10 5                                  | 2 2 1                             |
|                | Case 26| 100 10 10                                | 2 2 1                             |
|                | Case 27| 10 10 1                                  | 10 10 1                           |
|                | Case 28| 10 10 1                                  | 20 20 1                           |
|                | Case 29| 10 10 1                                  | 10 2 5                            |
|                | Case 30| 10 10 1                                  | 20 2 10                           |
| 9.24%          | Case 31| 10 10 1                                  | 2 2 1                             |
|                | Case 32| 50 50 1                                  | 2 2 1                             |
|                | Case 33| 100 100 1                                | 2 2 1                             |
|                | Case 34| 50 10 5                                  | 2 2 1                             |
|                | Case 35| 100 10 10                                | 2 2 1                             |
|                | Case 36| 10 10 1                                  | 10 10 1                           |
|                | Case 37| 10 10 1                                  | 20 20 1                           |
|                | Case 38| 10 10 1                                  | 10 2 5                            |
|                | Case 39| 10 10 1                                  | 20 2 10                           |
result means that the gas production performance in the Class 1 hydrate reservoir is closely related to hydrate dissociation. For Class 1 hydrate reservoir with low initial gas saturation, the correlations of the gas production rate with $R^*_{D}$ and $R_D$ are consistent (Table 6), indicating that the gas production rate is less affected by secondary hydrate formation. This result occurs mainly because the secondary hydrates form in the upper part of the dissociation front or at the top of the GHBS (Figures 7 and 9), hardly affecting the gas production performance. However, for a Class 1 hydrate reservoir with high initial gas saturation, the correlation between the gas production rate and $R_D$ is lower than that with $R^*_{D}$, showing that the gas production rate is affected by secondary hydrate formation. The possible reason for this phenomenon is that secondary hydrates form in the middle of the GHBS or at the hydrate-gas interface, thereby significantly affecting the hydrate dissociation behavior and fluid migration during production (Figures 12 and 14).

In summary, the gas production rate presents a high correlation with the hydrate dissociation ratio in Class 1 hydrate reservoirs with different permeabilities. A higher permeability accelerates pressure transfer and results in more significant hydrate dissociation, increasing the production performance of hydrate-originating gas. This outcome means that the hydrate dissociation volume is one of the main factors affecting the gas production performance from similar hydrate reservoirs.

### 3.4 Effect of depressurization pressure on production performance

Depressurization pressure is an important impact factor of gas production from natural gas hydrate-bearing sediments. The main factor for choosing dissociation pressure is gas production capacity. Here, a relatively high bottom-hole constant pressure (i.e., 6 MPa) is further considered. That is, 18 cases are established to investigate the effect of the depressurization pressure on production performances in Class 1 hydrate reservoir with different initial gas saturations and
permeabilities (Table 7). Here, several representative cases are selected to compare with the results under the bottom-hole pressure of 4.5 MPa.

As shown in Figure 17, when other parameters remain constant in Class 1 hydrate reservoirs with relatively low initial gas saturations (5.24%), the $Q_g$ increases as the bottom-hole pressure decreases. This is because a high differential pressure between the borehole and hydrate-bearing reservoir accelerates the hydrate dissociation and gas production. The difference between Case 7 and Case 9 is slightly larger than that between Case 24 and Case 26. This implies that the effect of anisotropic permeability on gas production is more significant under a lower bottom-hole pressure. In addition, a lower bottom-hole pressure can increase $R_{gw}$ to some extent, and the increase is more obvious when significantly accelerating permeability of hydrate reservoir.

Similarly, the $Q_g$ and $R_{gw}$ are also facilitated if the bottom-hole pressure is reduced and other parameters remain constant in Class 1 hydrate reservoirs with relatively high initial gas saturation (9.24%) (Figure 18). The difference in prediction results between Case 33 and Case 35 becomes smaller compared with that between Case 15 and Case 17, but the difference in predictions between Case 19 and Case 21 is inconspicuous even though the bottom-hole pressure decreases. The other comparisons among different conditions can be found in the Supplement and the similar conclusions can be drawn.

In general, a low bottom-hole pressure is conducive to gas recovery from Class 1 hydrate reservoir with different permeabilities.

4 | CONCLUSIONS

In this study, a reservoir-scale model is established to analyze the production performances from a single-well, which is as a part of a multi-well system involving vertical wells installed on a regular areal pattern. The effects of the absolute permeability on gas recovery from hydrate reservoir containing underlying free gas layer with different initial gas saturations
are systematically investigated. Meanwhile, the effects of secondary hydrate formation and bottom-hole pressure on production efficiency are also analyzed. Based on qualitative and quantitative comparisons of the simulation results, the following conclusions are drawn:

1. The gas recovery is limited in the Shenhu Class 1 hydrate reservoir with a relatively low gas saturation layer. In contrast, high initial gas saturation has a positive influence on gas production performance. However, more secondary hydrates may form near the hydrate-gas interface, causing a decrease in the hydrate dissociation ratio and delaying the initial dissociation time of the whole system. Therefore, the gas saturation of underlying free gas layer should be considered as a key sensitive parameter in the production evaluation stage.

2. For Class 1 hydrate reservoir with low initial gas saturation, increasing the absolute permeability of the hydrate-bearing formation as much as possible, especially the horizontal permeability, enhances the gas production performance, and decrease the PWIT, while increasing the horizontal permeability in hydrate formation significantly increases the risk of secondary hydrate formation. The impact of secondary hydrate formation on the hydrate dissociation ratio is remarkable once the absolute permeability of the hydrate layer increases by more than 5 times.

3. For Class 1 hydrate reservoir with high initial gas saturation, increasing the absolute permeability of the hydrate-bearing layer or gas layer favors fluid extraction and gas recovery. Comparatively, a high horizontal permeability (permeability anisotropy more than 10) in the hydrate formation is more significantly beneficial for enhancing long-term gas production performance and decreasing the PWIT. The gas production rate can be increased by approximately seven times when the absolute permeability of the reservoir increases by tenfold. However, once the permeability anisotropy is larger than 5, the greater the horizontal permeability, the more secondary hydrates form. The secondary hydrate formation decreases the hydrate dissociation ratio in this type of reservoir.

4. A low bottom-hole pressure is advantageous for enhancing the gas production performance in Class 1 hydrate reservoirs with different permeabilities. Furthermore, the gas production rate presents a high correlation with the hydrate dissociation ratio in such reservoirs. Therefore, the hydrate dissociation ratio and bottom-hole pressure are other main factors affecting the production performance for similar Class 1 hydrate reservoirs involving a multiple-well system in addition to the above-mentioned gas saturation of underlying free gas layers.

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SUPPORTING INFORMATION
Additional supporting information may be found online in the Supporting Information section.

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