MODELING AND ANALYSIS

Gas production from a silty hydrate reservoir in the South China Sea using hydraulic fracturing: A numerical simulation

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Abstract
The low permeability of silty hydrate reservoirs in the South China Sea is a critical issue that threatens safe, efficient, and long-term gas production from these reservoirs. Hydraulic fracturing is a potentially promising stimulation technology for such low-permeability reservoirs. Here, we assess the gas production potential of a depressurization horizontal well that is assisted by the hydraulic fracturing using numerical simulation according to field data at site SH2 in this area. In addition, the number of horizontal wells drilled is discussed if commercial production is to be performed at this site. The results show that the production potential can be significantly stimulated at the early production stage by adopting hydraulic fracturing in this reservoir due to a better depressurization effect. However, the increase in gas recovery gradually decreases with the continuous dissociation of gas hydrates, and the evolution trend is similar to that in a reservoir without stimulation during later periods of gas production because the dissociation front gradually moves away from the fractures. From the perspective of production potential, using a horizontal well scheme assisted by the hydraulic fracturing technology for gas recovery from a hydrate deposit can sharply reduce the number of operation wells, shorten the drilling operation time, and boost the economic efficiency. The horizontal well scheme may be an effective way to increase the gas yield if the application of quickly deployed horizontal wells and hydraulic fracturing techniques in such hydrate reservoirs greatly increases in the near future.

KEYWORDS
horizontal well, hydraulic fracturing, natural gas hydrate, production potential, South China Sea
1 | INTRODUCTION

As an alternative energy source in the future, natural gas hydrates that are mainly distributed in submarine and permafrost regions have attracted a large amount of attention since the total carbon content in gas hydrates is twice as large as that in conventional fossil fuel available now.1-4 According to the estimation of Kvenvolden,5 the amount of gas trapped in the global gas hydrate accumulations is up to 2 × 10^16 m^3. Therefore, gas recovery from hydrate deposits can meet the rapidly escalating global energy demand whether the hydrate deposits could be extracted efficiently and safely.

At present, the popular methods for extracting gas from hydrate deposits include depressurization, thermal stimulation, inhibitor injection, CO_2 replacement, and solid fluidization.4,6-9 However, previous numerical simulations and field trials have demonstrated that pure thermal stimulation and inhibitor injection may result in relatively high costs and only obtain a limited effectiveness.10-13 Furthermore, injecting inhibitors is not environmentally sound and may cause some pollution in the formation. Although CO_2 replacement serves double duty as a method for energy source extraction and greenhouse gas sequestration, the contact between the injected CO_2 and CH_4 hydrate will be hindered by the released water and formation of CO_2 hydrates on the outside of CH_4 hydrates.14 Meanwhile, migration will become clogged, causing a relatively low gas recovery rate, which has also been demonstrated by the CH_4-CO_2 exchange test on the northern slope of Alaska.15 Solid fluidization may destroy the seabed ecology and environment and increase the operation risk at the same time. Thus, compared to the above production methods, depressurization is greatly preferred by scientists because the method is applicable to most hydrate reservoirs with different permeabilities and is uniquely suited to allow the gas production rate to increase to match the increasing permeability.16 Furthermore, depressurization is relatively simple and effective, and the possibility of secondary hydrate formation can be eliminated by controlling the production pressure. Consequently, many investigations (eg, Refs. 17-33) have been performed recently, and numerical simulations have still focused on depressurization that is aimed at commercial production from potential target areas. In practice, depressurization has also been widely adopted in field trials in Mallik,34 the eastern Nankai Trough,35,36 and the South China Sea.37 The test results have increased our confidence in the available gas production induced by depressurization from hydrate reservoirs. However, the above predicted and field test gas recovery rates cannot approach the commercial production level. Based on previous investigations of hydrate dissociation,38,39 the gas recovery is mainly governed by the dissociation contact area. If artificial fractures can be created in gas hydrate-bearing sediments (GHBS), the surface contact area between the pores and solid hydrates will increase to accelerate the dissociation, and these fractures can provide pathways for the water and gas to enter into the wellbore.38,41 It is well known that hydraulic fracturing technology is widely used in natural oil and gas reservoirs to stimulate production.42 Therefore, using this method to assist the gas production from GHBS by depressurization may present an exciting opportunity. The suggestion of creating artificial fractures in GHBS has been proposed for a long time,38 but there are certain controversial voices because fracturing the layers above or below the GHBS may give rise to potential gas seepages, uncontrolled dissociations, or blowouts.14 However, GHBS are usually buried in shallow deposits with unconsolidated and low-stress characteristics, which are different from those of consolidated oil and gas reservoirs. Therefore, the fracturing area may be controlled if a proper pressure is employed. Many investigations on hydraulic fracturing in unconsolidated materials have been reported, specifically in soils and soft rocks, which are similar to marine gas hydrate deposits.44-48 In addition, most hydrate reservoirs discovered in nature are covered by low permeability overburdens, such as the eastern Nankai Trough49,50 and South China Sea,29 which can prevent the release of methane from leaking uncontrollably. In addition, these issues may not be concerns because hydrates are a self-preserving material.52 As long as hydrates are under stable thermodynamic conditions, the transient endothermic dissociation of hydrates into gas will be halted.40,41 Therefore, fracturing hydrate reservoirs before gas production by depressurization may be feasible and provide an alternative approach to extract gas more effectively. In fact, certain studies have been reported recently. For example, Konno et al21,23 and Too et al40 have separately investigated the feasibility of creating artificial fractures in their synthetically formed methane hydrates in sand specimens. They have found that hydraulic fracturing is a promising well stimulation method for low-permeable gas hydrate reservoirs. The detailed status of fracturing methane hydrates in sands can be found in the review concluded by Too et al.41 Additionally, Chen et al53 have preliminarily reported the effect of fracturing technology on the production efficiency of natural gas hydrates by numerical simulation combined with vertical well design and fluid jet technology based on field data. They have paid more attention to the influence of the horizontal crack quantity and space on gas recovery. According to their research, the gas production rate can still not match the commercial gas production level, even though fractures can effectively improve the exploitation efficiency in a low permeability hydrate reservoir. The main reason is that the thickness of GHBS along the vertical direction is limited, which inhibits the increase in the yield. A bonus is that the performance of a horizontal well operated by depressurization can deliver more efficient hydrate dissociation based on the previous evaluation of Moridis et al54; horizontal
drilling in an unconsolidated shallow formation (i.e., GHBS) has been implemented successfully in the Nankai Trough. Therefore, in this paper, we evaluated the gas production potential using horizontal well design and assisted the design with hydraulic fracturing stimulation technology before depressurization based on field data from the South Sea China. Meanwhile, the influences of the fracturing direction on gas extraction were analyzed and compared, which may provide certain valuable suggestions for field operations in similar reservoirs.

2 | SIMULATION MODEL

2.1 | Background

The research area is located in the central part of the northern slope of the South China Sea, between the Xisha Trough and the Dongsha Archipelago. The first Chinese expedition to drill gas hydrates, GMGS-1, was undertaken in this area in 2007 (Figure 1). A total of eight sites were drilled and well-logged in this survey, with cores recovered at five of these sites, including three sites with recovered gas hydrate samples (sites: SH2, SH3, and SH7). According to the investigation, site SH2 was one of the most favorable candidate targets and was near the first offshore test performed in 2017 in this area. Core sampling and well logging analysis performed at this site indicated the distributions of gas hydrates at depths of 185-229 m below the seafloor (mbsf), with a thickness of ~44 m and porosity of 40%, in an area with a water depth of 1235 m. The highest gas hydrate saturation from pore water freshening could be up to 47% (Figure 2), and the gas released from these hydrates was originally derived from microorganisms. In situ measurements showed that the bottom temperature was approximately 4°C with a geothermal gradient of 46.9°C·km⁻¹. In addition, the formation lithology was mainly silt with a millidarcy-range intrinsic permeability.

2.2 | Numerical simulation code

Gas production prediction involves coupled flow and thermal processes because of the special reserve conditions of GHBS. Therefore, the model built should handle the complex multifield coupling processes and cover different phases. In this work, TOUGH + HYDRATE software was employed to address this issue because the software was generally used to simulate gas recovery from hydrate reservoirs in marine and permafrost regions. The geomechanical response was not considered because the influence of effective stress variation on the sediment and fracture properties in GHBS at this site during depressurization is currently unclear, even though the coupled thermo-hydro-mechanical model was proposed and used to perform the coupling processes during drilling and gas extraction.
recovery. However, the assigned permeability of fractures takes the influence of the effective stress into account. The latter means that the value adopted is the experimental measurement in other sediments after which the bottom hole pressure remains constant after initially decreasing (i.e., the assigned fracture permeability is measured at the corresponding effective confining pressure condition). According to the comparison performed by Kowalsky and Moridis and the investigation conducted by Tang et al., the equilibrium model is more favorable for modeling long-term processes, so we have used the equilibrium model in our simulation.

2.3 Model construction

In this work, we investigate the stimulated production performance with special emphasis on hydraulic fracturing and compare these results with the production potential using a conventional horizontal well. Therefore, we have defined three different cases as follows:

1. Case 1: gas production using conventional horizontal well design
2. Case 2: gas extraction using a horizontal well with vertical fractures in the GHBS
3. Case 3: gas recovery using a horizontal well with horizontal fractures in the GHBS.

The reasons for the two different fracture directions considered can be summarized as follows. Natural gas hydrates in the Shenhu area of the South China Sea are distributed in poorly consolidated sediments near the seafloor, so the horizontal stress may be lower than that in the vertical direction. This situation may give rise to vertical fractures in the GHBS if fracturing technology is adopted. However, the occurrence of hydrates in the sediment may increase the cohesion of the deposits. If the deposits are heterogeneous, horizontal fractures may be created under the same operating conditions.

As shown in Figure 3, the simulated hydrate deposits are based on the GHBS described at site SH2 in the Shenhu area. The model built for gas production from this site uses a horizontal well. According to previous research performed by Li et al in similar area, the case involves a system of parallel horizontal wells, with a well spacing of 60 m. A horizontal well is located in the center of the hydrate reservoir, with a radius of 0.1 m, which can prevent the free water in the overburden and underburden from entering into the wellbore at the beginning. The geometry of the simulated domain represents a unit length (=1 m) of the horizontal well and can extend laterally. In addition, a thickness of 104 m (i.e., the thickness of the GHBS is 44 m, and the thickness of both the overburden and underburden layers is 30 m) is employed for the model domain along the vertical direction. Based on the studies of Moridis and Kowalsky and Moridis et al., 30-m thick layers are sufficient to depict the boundary effects of heat exchange and pressure propagation. Additionally, the inner and outside boundaries are also very important for gas production prediction.

In this study, the wellbore is assumed to be a pseudo-medium, with a porosity of \( \Phi_W = 1.0 \), \( k_x = k_y = k_z = 5.0 \times 10^{-9} \text{ m}^2 \), and a capillary pressure of \( P_c = 0 \). Meanwhile, the fractures are also assigned the

![FIGURE 2](image-url) The hydrate saturation profile inferred from pore water freshening (modified from Ref. 51)
same values except the permeability. According to Fan et al. the fracture length and width in weakly consolidated sandstone can be up to 28 m and 30 mm when using high-efficiency fracturing fluid, respectively. In addition, Konno et al. have also investigated the fracture characteristics in unconsolidated sediments by cyclic fracturing using X-ray computed tomography. The researchers observed that the maximum fracture width can approach 60 mm after the second injection. Because the thickness above and below the wellbore is limited (22 m) as well as the low hydrate saturation at the top and bottom of the GHBS (Figure 2), the fracture length is assumed to be 16.75 m. Meanwhile, the width of the fracture is 4 mm based on some field experiences because it will close when gas recovery by depressurization (∆P ≈ 10.5 MPa) is implemented after fracturing even though its width can reach several centimeters. We did not consider the variation in the width along the two directions in this work. According to the experiments on the effects of the width, generation method, and filler material of an artificial fracture under different confining pressures on its permeability performed by Liu et al., we have obtained the permeability of the fractures (≈2.0 × 10⁻¹¹ m²) adopted in this study. Specifically, the bottom hole pressure decreases from its original to 4.5 MPa within 1 day and then remains constant until the simulation ends (i.e., 3 years). This depressurization scheme refers to the first field trial performed in the eastern Nankai Trough. In addition, there is no flow of fluids and heat through the lateral boundaries (i.e., vertical sides) of the domain due to the symmetry, and the top and bottom boundaries are kept at a constant temperature and pressure. The main modeling parameters and physical properties, including the overburden and underburden used in TOUGH + HYDRATE, are given in Table 1.
2.4 | Domain discretization

Figure 4 shows a schematic of the meshes employed in predicting the gas extraction from the GHBS under three different conditions (i.e., Cases 1, 2, and 3). Because of symmetry, only half of the domain is considered, which can reduce the divided meshes and shorten the running time. Specifically, the model area is discretized into 6748, 6943, and 6885 elements in a Cartesian coordinate system \((x, y, z)\) in TOUGH + HYDRATE (Figure 4), respectively. The top and bottom boundary cells are inactive elements with a constant temperature and pore pressure during the simulations. Previous research\(^{64}\) has indicated that phase transitions and heat and mass transfersences around the borehole are rapid, meaning that a very fine discretization (0.1~0.5 m) is used in this region, as shown in Figure 4. In addition, mesh refinement (~0.5 m) is also employed between the interfaces of the GHBS and burdens.

2.5 | Initial conditions

As described above, the natural gas hydrates in the Shenhu area of the South China Sea are distributed in poorly consolidated sediments near the seafloor, which means that the pore water in the sediments can exchange with the sea-bottom water. In other words, the sediment pore water pressure can be assumed to be hydrostatic,\(^{83}\) so we can use the following empirical formula\(^{84}\) to calculate the pressure:

\[
P_{pw} = P_{atm} + \rho_{sw} g (h + z) \times 10^{-6}
\]

where \(P_{pw}\) is the hydrostatic pore water pressure in MPa, \(P_{atm}\) is the standard atmospheric pressure of 0.101325 MPa, \(h\) is the water depth in m, \(z\) is the depth of the sediment from the seafloor in m, \(g\) is the acceleration due to gravity in \(m\cdot s^{-2}\), and \(\rho_{sw}\) is the average seawater density in \(kg\cdot m^{-3}\). The water depth at site SH2 is 1235 m, so the pore pressure at \(Z = 229\) mbias can be determined (15.24 MPa). In addition, the seafloor temperature here is approximately 4°C. These conditions, combined with the known geothermal gradient of the GHBS listed in Table 1, mean that the initial temperature at this depth can be calculated (14.69°C). According to the hydrate pressure-temperature \((P-T)\) equilibrium curve, hydrates can maintain stability under the above initial conditions. Similarly, we can obtain the other initial conditions in the whole simulation domain, as shown in Figure 5.

| Parameters | Value | Parameters | Value |
|------------|-------|------------|-------|
| Overburden thickness \((\Delta Z_O)\) | 30 m | Grain-specific heat \((C_s)\) | 1000 J kg\(^{-1}\)°C\(^{-1}\) |
| Underburden thickness \((\Delta Z_U)\) | 30 m | Wet thermal conductivity | 2.917 W m\(^{-1}\)°C\(^{-1}\) |
| GHBS thickness (15 thin layers) | 44 m | Dry thermal conductivity \((\lambda_H)\) | 1.0 W m\(^{-1}\)°C\(^{-1}\) |
| Fracture length \((L_f)\) | 16.75 m | Intrinsic permeability of all formations | \(k = k = k = 1.0 \times 10^{-14} \text{ m}^2\) \((=10 \text{ mD})\) |
| Borehole radius \((r_w)\) | 0.10 m | Intrinsic permeability of fractures | \(k = k = k = 2.0 \times 10^{-11} \text{ m}^2\) \((=20 \text{ D})\) |
| Final bottomhole pressure \((P_{bw})\) | 4.5 MPa | Composite thermal conductivity model\(^a\) | \(\lambda_c = \lambda_{Hs} + \left( S_A^{1/2} + S_H^{1/2} \right) \) 
\(\lambda_{Hs} = \lambda_{Hs} + \Phi S_{ir} \) |
| Initial bottom temperature of GHBS \((T_s)\) | 14.69°C | Capillary pressure model\(^b\) | \(P_{cap} = -P_0 [S^*]^{-1} - 1 \) 
\(S^* = (S_A - S_{ir,A}) / (S_{m,A} - S_{ir,A})\) |
| Initial bottom pressure of GHBS \((P_s)\) | 15.24 MPa | Fracture width \((L_w)\) | 4 mm |
| Water salinity \((X_i)\) | 3.05% | Composite thermal conductivity model\(^a\) | \(\lambda_c = \lambda_{Hs} + \left( S_A^{1/2} + S_H^{1/2} \right) \) 
\(\lambda_{Hs} = \lambda_{Hs} + \Phi S_{ir} \) |
| Initial saturation in GHBS | \(S_H = 0-0.47\) | \(S_{ir,A}\) | 0.15 |
| Porosity of overburden \((\Phi_{o})\) | 0.42 | Relative permeability model\(^c\) | \(k_{IA} = [(S_A - S_{ir,A})(1 - S_{ir,A})]^{n} \) 
\(k_{iG} = [(S_G - S_{ir,G})(1 - S_{ir,A})]^{nG} \) |
| Porosity of GHBS \((\Phi_H)\) | 0.40 | \(P_0\) | 10\(^5\) Pa |
| Porosity of underburden \((\Phi_U)\) | 0.38 | \(n\) | 5 |
| Compression coefficient \(a\) | \(1.00 \times 10^{-8} \text{ Pa}^{-1}\) | \(nG\) | 3 |
| Grains density \((\rho_s)\) | 2600 kg m\(^{-3}\) | \(S_{ir,G}\) | 0.05 |
| Geothermal gradient | 46.9 K km\(^{-1}\) | \(S_{ir,A}\) | 0.50 |

\(^{a}\)Ref. 89
\(^{b}\)Ref. 90
\(^{c}\)Ref. 62

\(\Delta Z_O, \Delta Z_U\) are defined as the thickness of overburden and underburden, respectively.

\(\lambda_{Hs}\) is the composite thermal conductivity of the GHBS.

\(S_A, S_H, S_{ir,A}, S_{ir,G}\) are the initial methane saturation in the gas hydrate phase, the hydrate saturation, and the irreducible water saturation, respectively.

\(\Phi\) is the porosity of the formations.

\(\Phi_{IR}\) is the porosity of fractures.

\(\lambda\) is the thermal conductivity.

\(\lambda_{Hs}\) is the dry thermal conductivity of hydrate.

\(\rho_{sw}\) is the average seawater density in kg m\(^{-3}\).

\(S_{ir}\) is the irreducible water saturation.

\(\Phi_{IR}\) is the porosity of fractures.

\(P_{atm}\) is the standard atmospheric pressure.

\(P_{bw}\) is the final bottomhole pressure.

\(P_s\) is the initial bottom pressure of GHBS.

\(P_0\) is the atmospheric pressure.

\(\rho_s\) is the grains density.

\(\rho_{sw}\) is the average seawater density.

\(X_i\) is the water salinity.

\(\lambda_c\) is the composite thermal conductivity.

\(\lambda_{Hs}\) is the dry thermal conductivity of hydrate.

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3 | RESULTS AND ANALYSIS

3.1 | Spatial distributions of the physical properties in the reservoirs

The spatial evolutions of the physical properties, including pressure, temperature, hydrate saturation, and gas saturation, within 3 years (i.e., 1095 days) in the simulated hydrate deposits are shown in Figures 6-9. Research on the physical properties in formations can directly reveal the dissociation behaviors of hydrates in three different cases.

3.1.1 | Spatial distributions of the pressure

Figure 6 shows the evolution of the pressure in hydrate deposits under the three different schemes. The pressure in the vicinity of the wellbore and fractures will decrease with the reduction in bottom hole pressure. As production progresses, the extension of low pressure around the wellbore can be observed because of the gradual pressure diffusion, which indicates the effective depressurization areas under the corresponding conditions. As shown in Figure 6,
FIGURE 6  Evolution of the pressure in the simulated hydrate deposits

FIGURE 7  Evolution of the temperature in the simulated hydrate deposits
the depressurization response can be sharply improved once hydraulic fracturing is carried out before gas recovery. The main reason is that a rapid flow channel for gas and water is provided, thus contributing to the propagation of the pressure, which causes the higher driving force for hydrate dissociation. Specifically, the evolutions of the pressure in Case 2 and Case 3 are also different, particularly the distributions of low pressure and affected areas. The depressurization area in Case 2 is wider than that in Case 3 even though the significant low-pressure region (<6 MPa) is smaller in the early production period (≤90 days). This phenomenon will become reversed with continuous gas extraction. This difference can be ascribed to the following reasons: Vertical fractures are adopted in Case 2, which helps to accelerate the propagation of the pressure along the vertical direction at the beginning. However, the growing trend will weaken with depressurization because of the full dissociation of the hydrates in the upper and lower parts of the GHBS (because these parts can prevent water from flowing from the permeable burdens). In contrast, horizontal fractures are assigned in Case 3, which can use the undecomposed hydrate layers as water blocking formations (because the occurrence of gas hydrates can reduce the effective formation permeability significantly). Therefore, the depressurization in Case 3 at the middle and later stages is more notable and shows a better performance in the long-term production.

3.1.2 Spatial distributions of the temperature

The spatial evolutions of the temperature in Cases 1, 2, and 3 are shown in Figure 7. A significant low-temperature distribution can be observed at the dissociation front. The earlier the gas production occurs, the more notable the phenomenon is. This is consistent with the result from previous experiment performed by Li et al. The main reason is that hydrate dissociation is an endothermic process, and the process is extremely drastic at the early stage because of the high-pressure gradient (Figure 6). In addition, the isotherms will gradually move up from the bottom of the production well because the underlying high-temperature fluid flows into the extraction well little by little. This convective heat transfer is beneficial to accelerate the hydrate dissociation in the lower part of the GHBS. The reason why the mergence phenomenon does not occur above the wellbore is that the hydrate dissociation in this region is not drastic, which may prevent the fluid from entering into the wellbore to a certain extent because of the water blocking effect. In addition, a portion of the escaped gas with a high temperature can also suppress this situation. Comparing these three cases, we can also conclude that combining hydraulic fracturing with depressurization contributes to gas recovery from hydrate deposits and creating horizontal fractures presents the best production performance. These
results can be attributed to the most effective depressurization response and the most notable heat transfer from the surrounding sediments, specifically from the underburden.

### 3.1.3 | Spatial distributions of the hydrate saturation

Figure 8 shows the corresponding spatial distributions of the hydrate saturation under the above three conditions. It can be observed that the hydrates gradually dissociate after depressurization. The dissociation extent around the wellbore or/and fracture will increase with continuous production. From Figure 8, the hydrate dissociation in the lower part of the GHBS is faster than that in the upper part. The reason is that the underlying high-temperature fluid gradually enters into the production well because of permeable underburden (Figure 7), which helps convective heat transfer from surroundings and accelerates hydrate dissociation. Furthermore, the horizontal hydrate dissociation extent is different mainly due to the variable effective permeability that depends on the hydrate saturation. We can also find that the hydrate dissociation near the wellbore is governed by the fracture azimuth because these fractures help to extract gas and water effectively, thus resulting in better driving forces for dissociation in these regions. In addition, there are few secondary hydrates forming at the dissociation front or the edge of the horizontal fractures, particularly in the later period. The possible reason is that a portion of the released gas will move up due to the buoyancy, but becomes trapped by the high hydrate saturation layer at the dissociation front. Therefore, secondary hydrates can form in these areas under the appropriate pressure and temperature conditions. With regard to the secondary hydrates around the horizontal fractures, they are mainly because a large volume of free gas will enter this area, and the pressure drop is not significant at the front of the fracture (as shown in Figure 6), causing secondary hydrates to easily form here. Based on the above analysis on the spatial evolutions of the pressure and temperature, it is easy to understand that the extent of hydrate dissociation in Case 3 is the maximum.

### 3.1.4 | Spatial distributions of the gas saturation

The spatial evolution of the free gas released, as shown in Figure 9, can directly reveal the gas production behavior. It can be observed that free gas occurs around the wellbore, but its saturation decreases with the sustained gas extraction caused by the decreasing pressure gradient. However, the horizontal distribution distance will increase, which results from the retrograde hydrate dissociation front from the wellbore. It is clear that the gas recovery can be notably stimulated if...
hydraulic fracturing is employed due to the increased driving force for hydrate dissociation; the production performance in Case 3 is the optimum due to the most effective depressurization and convective heat transfer in the GHBS. In addition, an interesting phenomenon is that there is no free gas appearing between the wellbore and the dissociation front in Case 3 at the middle and later stages, while free gas can still be found in the other two cases. This phenomenon illustrates that the dissolved gas plays a dominant role in long-term gas extraction when using the horizontal fracture scheme.

3.2 | Hydrate dissociation and gas release

Figure 10 indicates the quantitative evolution of the gas release and hydrate dissociation extent per unit length of the horizontal well (i.e., 1 m). It can be found that hydrates will dissociate with decreasing well pressure, and the released gas rate increases at the beginning because of the high-pressure gradient within 1 day. After the gradient reaches its maximum, the gas release rate will gradually decrease due to the subdued pressure difference. According to Figure 10A, the peak rates are approximately 105, 560, and 780 m³·d⁻¹ in Cases 1, 2, and 3, respectively. It is clear that hydrate dissociation assisted by hydraulic fracturing can significantly stimulate in the early period (≤450 days), but there is a negligible effect on the dissociation at a later stage. The main reason is that combining depressurization with hydraulic fracturing presents a better decompression performance in the early period (Figure 6). As production proceeds, hydrates are located far from the wellbore and fractures due to the continuous dissociation (Figure 8), which gives rise to a similar evolution trend because of the relatively similar low-pressure gradient at the dissociation front caused by the low formation permeability and permeable burdens. Undoubtedly, the gas release rate in Case 3 is the highest based on the analysis of the spatial distributions of the pressure and temperature (Figures 6 and 7). Meanwhile, the corresponding cumulative gas release volumes and residual hydrate mass fraction are shown in Figure 10B. The highest cumulative gas release volume in Case 3 is larger than 30 000 m³ within 3 years, followed by that of Case 2, which is approximately 24 000 m³, and the lowest value is that of Case 1 (≈15 500 m³). These findings are the result of the different depressurization effects, that is, Case 3 > Case 2 > Case 1 (Figure 6). The hydrate dissociation extent in Case 3 is higher than 50%, which is much higher than those in Cases 1 (≈25%) and 2 (≈39%). This result demonstrates that hydraulic fracturing is an extremely effective stimulation method, and horizontal fracture design shows the best performance in this type of hydrate sediment.

3.3 | Gas and water production

Figure 11 shows the corresponding evolutions of the gas and water production rates (Q_{PT}, Q_{PG}, and Q_{W}) and cumulative methane and water trapped volumes (V_{PT} and V_{W}). The predicted gas recovery rates for the three different cases are shown in Figure 11A. It can be found that the gas production rate will sharply increase at the initial stage (≤1 day) because of the rapid drop in well pressure. After that, its decrease can be observed because the pressure difference between the sediment and wellbore declines after 1 day. In addition, the trapped free gas is the main source of the total gas recovery in the early period. However, the dissolved gas will take its place with continuous depressurization. The main reason can be found in Figure 9, which shows the evolution of free gas near the wellbore. It is clear that a large volume of free gas appears around the wellbore and/or fractures due to the rapid dissociation in the early period. Therefore, free gas
can be trapped easily because of the relatively high-pressure difference in the vicinity of the wellbore. As hydrate dissociation progresses, the dissociation front moves forward and gradually enters into the area with a low-pressure gradient (Figures 6 and 8). These phenomena cause a decrease in hydrate dissociation and extend the flow path for free gas at the same time, thus resulting in the dissolved gas playing a main role in the gas extraction in the later period. Depending on the hydrate dissociation, the gas production rate exhibits a similar evolutionary trend: The rate drastically increases and reaches a peak at the beginning and then begins to decrease. Comparing these three production schemes, we can conclude that creating fractures in the GHBS significantly contributes to the gas recovery, particularly horizontal fractures for gas extraction using a horizontal well in this area.

Figure 11B shows the water production rates (\(Q_W\)) vs time considering the three different designs, which is critical to determine the pumpage in the field. Similarly, \(Q_W\) increases first because of the high-pressure gradient, but does not decrease with depressurization at all times. The prediction is that \(Q_W\) will decrease in a very short time caused by the reduction in the pressure gradient after 1 day and then will increase afterward. This result is mainly because the water blocking effect will disappear due to the gradual dissociation of gas hydrates, so the water in the permeable burdens can invade into the GHBS and flow into the wellbore. Additionally, the water released from hydrate dissociation may also exacerbate its yield. It is interesting that the rising tendency in Case 3 is remarkably different. It is easy to understand that hydraulic fracturing provides better flow paths for water, thus causing its production increases in Cases 2 and 3. The reason for the different evolution trend in Case 3 is that horizontal fractures are created, which can take advantage of the water blocking effect as much as possible before full dissociation occurs above and below the fractures in the early period. Therefore, the water yield is lower than that in Case 2.
However, the hydrates around the wellbore and fractures will dissociate rapidly, thereby resulting in the disappearance of the water blocking effect. Meanwhile, the fractures extending in the horizontal direction are conducive to providing a wider flow area for the water in the overburden and underburden. Furthermore, more water is released from hydrate dissociation in Case 3. These combined reasons cause the significant increase in water extraction at the later stage.

$R_{GW}$ is regarded as a relative criterion to evaluate the production performance and is determined by $V_{PT}/V_W$. As shown in Figure 11B, the $R_{GW}$ value under the three schemes increases within 1 day and then gradually decreases. The $R_{GW}$ value in Case 3 is the highest, while the lowest value is observed in Case 2 within approximately 330 days. It is interesting that the $R_{GW}$ value in Case 1 will be the maximum afterward, followed by those of Case 3 and Case 2. These results are mainly caused by the gas and water production. Initially, a large volume of free gas can be released rapidly in Case 3 (Figure 9) because the horizontal fractures contribute to the depressurization. Meanwhile, the water in the overburden and underburden cannot enter into the wellbore easily because of the water blocking effect. Therefore, the $R_{GW}$ value of Case 3 is the highest at the early stage. However, as the water blocking effect gradually disappears, more water will be extracted due to better flow paths, thus resulting in the highest value of $R_{GW}$ of Case 3 being displaced by that of Case 1. The possible reason for the lowest $R_{GW}$ value of Case 2 is that although the gas production is accelerated by creating vertical fractures, the water extraction increases more sharply (Figure 10B). Additionally, the total gas and water production ($V_{PT}$ and $V_W$) are depicted in Figure 11C. It can be observed that the cumulative gas recoveries in Cases 1, 2, and 3 within 3 years are approximately 24 000 m$^3$, 33 000 m$^3$, and 40 500 m$^3$ per unit length of horizontal well, respectively. The corresponding water extraction rates approach 10 600, 22 000, and 24 000 m$^3$, respectively.

### DISCUSSION

In this section, the number of horizontal wells employed is discussed based on the above prediction results. The average gas and water production rates in the three cases within different production periods per unit length are summarized in Table 2. It is assumed that the length of the horizontal well is 500 m and the total gas recovery rate can reach the commercial level (≈3.0 × 10$^7$ m$^3$·d$^{-1}$); thus, the minimum number of wellbores that need to be drilled during the different production periods is summarized in Table 3. Specifically, when the depressurization is sustained for 1 year, at least 26 horizontal wells should be drilled to meet the commercial level requirement. However, the number will be significantly reduced to 15 if vertical fractures can be created at the same time. When horizontal fractures are formed instead, only 10 operation wells are necessary. That is, using horizontal wells assisted by fracturing technology can reduce the number of operation wells by 42.3% in Case 2 and 61.5% in Case 3 within 1 year, respectively, which helps to decrease the economic investment sharply. Under the condition that the production period is further extended, the necessary production wells within 3 years in Case 1 are approximately 36.5, while in Cases 2 and 3, the corresponding numbers are only 25 and 19. This result means that the number of production wells can still be reduced by 31.5% and 47.9%, respectively. Furthermore, it is possible to handle the extracted water based on the prediction results shown in Table 2 using current pumps. Therefore, using horizontal wells assisted by hydraulic fracturing technology to extract gas from hydrate reservoirs can drastically reduce the number of operation wells, shorten the drilling operation time, and boost the economic efficiency.

### CONCLUSIONS

Based on the data of the first exploration well (SH2) drilled in the Shenhu area of the South China Sea in 2007, the production potentials using a conventional horizontal well and stimulation by hydraulic fracturing are investigated. The numerical simulations undertaken during this study yielded the following results.

### TABLE 2  The average gas and water production rates in three cases within different production periods per unit length

| Time | 1 y | 2 y | 3 y  |
|------|-----|-----|------|
| Case 1 | Average gas production rate (m$^3$·d$^{-1}$) | 23.00 | 19.14 | 16.47 |
|       | Average water production rate (m$^3$·d$^{-1}$) | 3.43  | 4.34  | 4.99  |
| Case 2 | Average gas production rate (m$^3$·d$^{-1}$) | 40.18 | 29.40 | 24.05 |
|       | Average water production rate (m$^3$·d$^{-1}$) | 9.69  | 10.63 | 11.20 |
| Case 3 | Average gas production rate (m$^3$·d$^{-1}$) | 61.69 | 41.12 | 31.54 |
|       | Average water production rate (m$^3$·d$^{-1}$) | 9.49  | 11.45 | 12.32 |

### TABLE 3  The minimum number of wellbores that need to be drilled in the corresponding cases

| Time | 1 y | 2 y | 3 y  |
|------|-----|-----|------|
| Case 1 | Number of horizontal wells | 26  | 31.5 | 36.5 |
| Case 2 | 15  | 20.5 | 25   |
| Case 3 | 10  | 14.6 | 19   |
1. The gas production potential can be sharply improved at the early stage considering hydraulic fracturing because rapid flow channels for gas and water are provided, thus contributing to the pressure propagation. Creating horizontal fractures in the GHBS gives rise to the best production performance, and the prediction results are better than those when vertical fractures are created due to the optimal depressurization effect. Therefore, creating horizontal fractures to increase the yields in similar hydrate reservoirs may be preferred in the future.

2. Although a permeable underburden can suppress the depressurization effect, the underlying high-temperature fluid invades into the GHBS, thereby helping to accelerate the hydrate dissociation because of convective heat transfer. In other words, allowing appropriate fluids with high temperatures to flow into the GHBS from the surrounding sediments may present a better production performance than the operation in GHBS with only an impermeable underburden.

3. According to the predictions, using horizontal wells assisted by hydraulic fracturing technology to approach commercial production at this site can reduce the number of operation wells by approximately 42.3% and 61.5% within 1 year. If the production period is increased to approximately 3 years, the necessary production wells can still be decreased by 31.5% and 47.9%.

Using the hydraulic fracturing technology can significantly reduce the number of operation wells, shorten the drilling operation time and boost the economic efficiency, and may be an efficient stimulation method for gas recovery from hydrate reservoirs in the foreseeable future. Our work can provide valuable suggestions for reservoir reconstruction in an adjacent test site.

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