Numerical Evaluation of Gas Hydrate Production Performance of the Depressurization and Backfilling with an In Situ Supplemental Heat Method
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ABSTRACT: The depressurization and backfilling with an in situ supplemental heat method had been proposed to enhance the gas production of methane hydrate reservoir. This novel method is evaluated by a numerical simulator based on the finite volume method in this work. Based on the typical marine low-permeability hydrate-bearing sediments (HBS), a reservoir model with gas fracturing and CaO powder injection is constructed. The simulation results show that the stimulated fractures could effectively enhance the pressure drop effect. Moreover, the CaO injection could provide in situ heat simultaneously. Based on the sensitivity analysis of the equivalent permeability of fractures and the mass of CaO injection, it is found that a threshold fracture permeability exists for the increasing of gas production. The gas production increases with the equivalent permeability only when the permeability is smaller than the threshold value. Meanwhile, the more CaO are injected into reservoir, the larger volume of gas production. In general, this work theoretically quantifies the potential value of the depressurization and backfilling with an in situ supplemental heat method for marine gas hydrate recovery.

1. INTRODUCTION
Natural gas hydrate (NGH) is widely distributed in sub-oceanic sediments and in permafrost areas under low-temperature and high-pressure conditions. NGHs are solid, nonstoichiometric compounds formed by host water molecules with small guest molecules (mainly CH4). The global natural gas volume of NGH is estimated to be 2 × 1016 m3. NGH is considered to be a promising alternative source of energy. Current studies also focus on developing novel recovery methods for hydrate-bearing sediments (HBS), especially for NGH incased in clayed-silt sediments. Several hydrate drilling expeditions have been conducted in the South China Sea. It has been shown that HBS in the Shenhu area mainly contains fine-grained clayed silt. The permeability of the HBS is extremely low (1.5−70 mD). The basic principle of production is breaking the original phase equilibrium state of NGH. The equilibrium state is controlled by the temperature, the pressure, and the salinity of the surrounding geological environment. At present, conventional recovery methods mainly consist of depressurization, thermal stimulation, inhibitor injection, and CO2 exchange. Within these methods, depressurization and thermal stimulation are regarded as relatively economical and mature choices. The technical feasibilities of these methods have been proven with a successful hydrate trial production in the Shenhu area, South China Sea, but there still is a huge gap of magnitude between the trial results and the demand of commercial production. Without heat supplement, a single depressurization method brings a dramatic temperature drop and secondary formation of hydrate and ice blocks. Hence, heat supplement is also a technical route to increase production. Whereas, a steady and economical heat supplement is hard to be
obtained during a real production process. In addition, due to the success of hydraulic fracturing in shale gas production, some researchers plan to apply a similar technique into HBS. In situ reservoir stimulation is another potential way to promote gas recovery. The analyses of pilot tests and numerous simulations suggest that the most crucial factors to realize commercial production are continuous and effective pressure drop, steady and economical heat supplement, and in situ reservoir stimulation. Whereas, all these factors have not been considered.

Based on the above three factors, many scholars have put forward improved methods and new ideas based on conventional methods. Overcoming the extremely low permeability of HBS is the main challenge during the production because the depressurization effect is restricted by the low-permeability layer. In order to enlarge the range of pressure-drop zone and promote the depressurization effect, Zhao et al.\textsuperscript{16} put forward a novel method that forms artificial impermeable barriers from unconfined hydrate deposits that controls the depressurization effect in HBS, and this step avoids invalid dissipation of pressure drop in no-hydrate layers. The numerical simulation results show that the hydrate decomposition rate increases from 8.9 to 45.4\% by setting 90 m impermeable barriers. For the same purpose that expand the impact range of production wells, Zhang et al.\textsuperscript{17} built and artificial well around the original vertical well in order to enlarge the influence effect of the production wells on the circumference of the well. The simulation results show that gas volume is increased by more than four times and the farthest distance of hydrate dissociation front is increased by more than two times. Based on other critical perspectives of heat supplement, Sun et al.\textsuperscript{18} proposed a combined method to exploit shallow gas hydrate together with deep geothermal resources. Seawater is injected into a deep geothermal reservoir, and then it brings the reservoir heat into shallow HBS after circulation. The numerical simulation results imply that better production performance is obtained compared with depressurization and thermal stimulation. Based on the same routine for seeking economical heat flow, Liu et al.\textsuperscript{19,20} put forward a similar recovery approach named geothermal energy-assisted natural gas hydrate recovery method (GEAN). In addition, some recovery approaches named geothermal energy-assisted natural methods, CT technology has been widely applied into physical analyzing the hydraulic fracturing results.\textsuperscript{25}

2. SIMULATION METHOD

In this research, a novel NGH simulator was developed and utilized. Five components (hydrate, water, gas, ice, and salinity) and three phases (gas, liquid, and solid) are considered in this simulator. Several assumptions made in the simulator are as follows: (1) Gas and water flow in HBS follows Darcy’s law. (2) Heat transfer includes convection and conduction. (3) The hydrates are pure methane hydrates. (4) The compressibility of matrix and fluids are considered. (5) This work is based on the equilibrium of hydrate dissociation.\textsuperscript{32}

2.1. Main Govern Equations. Based on Pruess et al.,\textsuperscript{33} mass and energy balance considerations are as follows:

\[ \frac{d}{dt} \int_{V_n} M^f dV = \int_{\Gamma_n} F^F n d\Gamma + \frac{d}{dt} \int_{V_n} q^f dV \]  

(1)

where \( V \) is the volume, \( V_n \) is the volume of subdomain \( n \), \( M^f \) is the mass accumulation term of component \( \kappa = w, m, i, h \), \( \Gamma \) is the surface area, \( \Gamma_n \) is the surface area of subdomain \( n \), \( F^F \) is the Darcy flux vector of component \( \kappa \), \( k \) is the inward unit normal vector, \( q \) is the source/sink term of component \( \kappa \), and \( t \) is the time.

The mass accumulations terms for the several components are given by

\[ M^f = \sum_{\beta=A,G,I,H} \phi \rho_\beta X^\beta_W \]  

(2)

where \( \phi \) is the porosity, \( \rho_\beta \) is the density of phase \( \beta \), \( S_\beta \) is the saturation of phase \( \beta \), and \( X^\beta_W \) is the mass fraction of component \( \kappa = w, m, i \) in phase \( \beta \).

The mass flux of liquid phase is given by

\[ F^s_A = -k_A \frac{dP_A}{\mu_A} (\nabla P_A - \rho_A g) \]  

(3)

where \( k \) is the rock intrinsic permeability, \( k_A \) is the relative permeability of the aqueous phase, \( \mu_A \) is the viscosity of the aqueous phase, \( P_A \) is the pressure of the aqueous phase, \( g \) is the gravitational acceleration vector.

The mass flux of gas phase is given by
\[ F_G^\kappa = -k_0 \left( 1 + \frac{b}{P_G} \right) \frac{k_\kappa \rho_G}{\mu_G} \chi_G^\kappa \left( \nabla P_G - \rho_G g \right) \kappa \equiv \omega, m \]

where \( k_0 \) is the absolute permeability at large gas pressures, \( b \) is the \( b \)-factor accounting for gas slippage effects, \( k_G \) is the relative permeability of the gaseous phase, and \( \mu_G \) is the viscosity of the gaseous phase.

The energy accumulation terms are given by

\[ M^\theta = (1 - \phi) \rho_R C_R T + \sum_{\beta=A,G,H,I} \phi_S \phi_{\beta} U_{\beta} + Q_{\text{diss}} \]

where \( \rho_R \) is the density of rock, \( C_R \) is the heat of the dry rock, \( U_{\beta} \) is the specific internal energy of phase \( \beta \), and \( Q_{\text{diss}} \) is the reaction heat of hydrate dissociation.

The heat flux term is given by

\[ F^\theta = -\bar{k}_\theta \nabla T + \sum_{\beta=A,G} h_\beta F_{\beta} \]

where \( \bar{k}_\theta \) is the composite thermal conductivity of the medium/fluid ensemble, \( T \) is the temperature, and \( h_\beta \) is the specific enthalpy of phase \( \beta \).

The description of reaction heat of hydrate dissociation is given by

\[ Q_{\text{diss}} = \Delta \left( \phi \rho_H S_H \Delta H^\theta \right) \]

where \( \rho_H \) is the density of hydrate, \( S_H \) is the saturation of hydrate, and \( \Delta H^\theta \) is the specific enthalpy of hydrate dissociation/formation.

**2.2. Simulator Verification.** The most widely adopted simulator in the field of hydrate numerical simulation is TOUGH + hydrate developed by LBNL. Therefore, a one-dimension reference case described in the T + H manual was repeated to verify the accuracy and validity of self-developed hydrate simulator. The specific model parameters and initial and boundary conditions of the reference case are listed in Table 1.

| parameter                  | value   |
|----------------------------|---------|
| model length (m)           | 1       |
| grid number                | 10      |
| initial pressure (MPa)     | 4       |
| initial temperature (K)    | 274.35  |
| boundary temperature (K)   | 318.15  |
| porosity                   | 0.3     |
| intrinsic permeability (mD)| 30      |
| thermal conductivity (W/m/K)| 3.1    |

The overall tendency of the \( \text{CH}_4 \) released rate is similar (Figure 1). The discretization effects are obvious in the distinctly “segmented” appearance of the curves, which exhibit “bumps” corresponding to the periodic rate patterns. The result indicates that not only the value of gas volume released from hydrate but also the evolution trend could fit well with the result of T + H (Figure 2).
fracturing technique is the most urgent step, which needs quantitative evaluation.

Because there is no data about high pressure powder-gas fracturing to refer to, this work assumed that the fracturing and CaO injection are feasible in HBS. Therefore, the powder quantity and distribution are the main concerns in this study. However, the differences of fracture properties are found in numerical simulations and laboratory tests.\textsuperscript{18,36,37} According to the experimental results, the fracture length and width can approach 28 m and 30 mm in weak-cementing sand layers, respectively. The X-ray CT observation results indicate that the maximum width of fracture can reach 60 mm.\textsuperscript{24} The equivalent permeability and initial temperature of the fracturing zone are dominant parameters in the subsequent depressurization recovery.

3.2. Reservoir Numerical Model. 3.2.1. Model Geometry and Spatial Discretization. The model is divided into three zones, namely, overburden, hydrate-bearing sediment layer, and underburden from top to bottom, respectively. The thicknesses of the overburden, hydrate-bearing sediment layer, and underburden are set as 30, 20, and 30 m, respectively, which had been verified to be valid to reflect the boundary effect of the heat transfer and pressure propagation.\textsuperscript{35,38} The length in the x direction is 45 m. The length in the y direction is 1 m (i.e., horizontal well unit length).

In this work, the gas production performance of the depressurization and backfilling with in situ supplemental heat is investigated. Facilitating the effect of the high-pressure gas-powder fracturing is the emphasis of this study. Hence, several cases are defined to investigate the gas production performance (Figure 4, Table 2). Case 1 is the conventional horizontal well production scheme without fracturing and chemical reaction. Case 2 is the horizontal well production scheme combining with fractures (different equivalent permeabilities of fractures), which do not involve chemical reaction. Case 3 is the horizontal well production scheme with a high-pressure gas-powder fracturing technique (uniform equivalent permeability of fractures and different mass of CaO injection). The reason of setting radial fractures is getting the maximum of the reservoir stimulation effect to enhance gas production. The basis of this setting is that the fracturing process may stimulate the reservoir near the horizontal wells.

To simplify calculation, half of the 2D $X$–$Z$ plane is calculated. The entire simulation zone is discretized into 118 (in the $z$ direction) and 89 (in the $x$ direction) grid blocks. The specific settings of grid sizes in the $z$ direction are 0.5 m in HBS and 1 m in overburden and underburden, respectively. The grid size in the $x$ direction is 0.5 m. At last, a total of 10,502 grids are adopted in the simulation process (Figure 5).

3.2.2. Initial and Boundary Conditions. The detailed geologic parameters are selected with reference of Shenhu area, South China Sea, are listed in Table 3.\textsuperscript{16,39–41} The initial pressure and temperature at the bottom of HBS layer are 15.9 MPa and 288.25 K (no chemical reaction). The initial fluid pressure of the entire model region follows the hydrostatic distribution. The temperature distribution obeys the constant geothermal gradient of 0.045 K/km. In addition, the initial hydrate saturation and water saturation are 0.44 and 0.56, respectively. The overburden and underburden are in the water-saturation state.

Due to the lack of data, the equivalent permeability of fracture is a parameter to evaluate the flow capacity near the fractures. Its values are calculated by the cube’s law first, which is mainly obtained by the geometric characteristics of fractures. Then, we adjust the value of this parameter after referring the results of physical simulation experiments about the fracturing of hydrate-bearing sediments.\textsuperscript{41–43}

\begin{equation}
 k_i = \frac{A^3}{12H}
\end{equation}

where $A$ is the fracture aperture and $H$ is the thickness of the grid cells near the fractures in the model.
The equivalent permeabilities of fracture are set to $1 \times 10^{-11}, 1 \times 10^{-12}, 1 \times 10^{-13},$ and $1 \times 10^{-14}$ m$^2$ to analyze the sensitivity of the equivalent permeabilities of fractures (Table 4).

The initial temperature of the fracture surrounding the environment is controlled by the chemical exothermic reactions occurring between CaO and water. Given the heat transfer process, all heat released from exothermic reactions is converted to the initial temperature of the matrix sediments. Due to the lack of data about CaO injection, the mass of CaO injection is set as a variable to study the sensitivity of CaO. The masses are set to 5, 10, 15, and 20 t. The ideal heat supplement is the theoretical value of heat released from the chemical reaction between water and CaO. The heat loss is ignored during the simulation. The assumption is adopted that all the heat released from the chemical reaction between water and CaO is transformed into the initial temperature of sediment matrix. The density of CaO and specific heat capacity of the matrix sediments are 3.35 g/cm$^3$ and 800 J/kg/K, respectively. The ideal heat supplement are listed in Table 5. The initial values of temperature of 144 cells near the fractures are adjusted to reflect the in situ heat supplement effect.

$$
\text{CH}_4 \cdot 5.75\text{H}_2\text{O(s)} = \text{CH}_4(g) + \text{5.75 H}_2\text{O(l)} \Delta H_m
$$

$$
= 54.49 \text{ kJ/mol}
$$

$$
\text{CaO(s) + H}_2\text{O(l)}
$$

$$
= \text{Ca(OH)}_2(l) \Delta H_m
$$

$$
= -64.9 \text{ kJ/mol}
$$
The upper and lower grids of the reservoir model are the boundaries. The fixed temperature and pressure are set to above grids. There is no flux and mass exchange in lateral boundaries except the location of the production well. The horizontal well is set as the inner boundary. The constant production pressure (i.e., drawdown pressure) is set to 3 MPa. The simulation period is designed to be 3 years.

Figure 6. Temporal and spatial evolution of the hydrate saturation ($S_{\text{hyd}}$) $S_h$ in the simulated reservoir: (a) Case 1: conventional horizontal well method, (b) case 2-1: conventional horizontal well method with fractures, and (c) case 3-1: conventional horizontal well method with fractures and CaO.
4. RESULTS AND DISCUSSION

4.1. Hydrate Dissociation Behaviors. The temporal and spatial evolution of hydrate saturation $S_h$ under different base cases (case 1, case 2-1, and case 3-1) in the reservoir model is presented in Figure 6. The hydrate dissociation zone is limited to the horizontal well ambient environment in the conventional horizontal well. The hydrate decomposition front moves as concentric circles. The pressure drop is restricted for the low permeability in the HBS layer; meanwhile, the outside heat supplement is inadequate. The addition of fractures induces better depressurization performance. It is apparent that the hydrate dissociation zone expands dramatically due to the fast flow channel. Hence, the hydrate dissociation behaviors are more intense. Whereas, the hydrate dissociation mainly occurs near the fractures due to the pressure drop propagate to the position near fractures. Subsequently, the CaO is considered in recovery process. The results indicate that the hydrate dissociation behaviors are promoted further. The in situ heat supplement near the fractures is sufficient, which enlarge the hydrate dissociation range and improve the production performance. The hydrate dissociation front obviously approaches further in modified recovery method cases after the depressurization recovery of 3 years. The conventional method can only reach 5 m, but the modified recovery method can reach 20 m at most. For the further quantitative comparison of hydrate dissociation, the impact ratio ($R_{impact}$) of the area of the hydrate dissociation region ($S_{dissociation}$) to the area of the hydrate-bearing sediment layer ($S_{HBS}$) is calculated. The definition of the hydrate dissociation region is the region whose hydrate saturation is below initial value (0.44). The $R_{impact}$ values of cases 1, 2-1, 3-1 are 3.0, 18.7, and 42.7% respectively. The results indicate that the new method obviously improves the range of hydrate dissociation.

4.2. Gas and Water Production Behavior. The temporal evolution of cumulative gas production $V_G$ in the base case of the conventional recovery method (i.e., case 1), base case of fractures (i.e., case 2-1), and base case of fractures with CaO (i.e., case 3-1) is presented in Figure 7. The cumulative methane volume of the three base cases is 616, 2308, and 3263 ST m$^3$, respectively, during 3 year simulation periods. Compared with the conventional recovery method, the methane volume of the recovery method with fractures increases by 2.75 times and the methane volume of recovery method with fractures and CaO increases by 4.3 times. By contrast to the method with fractures, the methane production of combining fractures and CaO injection also increases by 41.3%. The reason for poor gas production of the conventional horizontal well method is that the production process is controlled by the sensible heat. $^{48}$ Whereas, the sensible heat is not sufficient at the late stage of dissociation. There is an acceleration phase in the curve of the case with fracture and CaO. The above phenomenon is caused by the injection of CaO. The injection of CaO supplies the huge in situ heat, which brings another increase in gas production. After the heat released from the reaction is transferred to the surrounding environment, the gas production rate approaches a steady value.

The evolution of cumulative water production $V_w$ in the three base cases is presented in Figure 8. The cumulative water production volume of the conventional horizontal well recovery method is 198 ST m$^3$. It is apparently less than the case of fractures (case 2-1) and the case of fractures with CaO (case 3-1). The total water production volumes of the two modified methods cases are significantly close (526 and 529 ST m$^3$). The above phenomenon indicates that CaO injection improves the gas production without increasing water production. The difference between case 2-1 and case 3-1 is the CaO injection. There is no CaO injection in case 2-1 and there is CaO injection (5 t) in case 3-1. In the model, we assume that the injection of CaO only provides the heat released from the chemical reaction and other influences with CaO are not considered in the simulation. The water production is mainly controlled by the flow capacity of fractures, but the CaO injection cannot...
significantly change the flow capacity of fractures under the abovementioned assumption. Therefore, the water productions of case 2-1 and case 3-1 are close to each other.

Based on the above analysis, it is obvious that the gas production is promoted simultaneously after adopting modified recovery methods. The hydrate dissociation rate and production efficiency increase for fractures and chemical reaction between CaO and water.

4.3. Evolution of Temperature and Pressure. To study the dynamic evolution characteristic of temperature and
pressure fields more quantitatively, three critical time points are chosen to analyze the temporal and spatial evolution of T–P fields (10 days, 100 days, 3 years). The depressurization performance of modified methods is better than the conventional horizontal well method. The reason causing this phenomenon is that the fractures form fast flow channels. However, the depressurization difference between the fracture case and the fracture case with CaO is not remarkable. The reason for similarity is that the CaO injection mass (5 t in case 3-
permeability, the increasing effect is remarkable that with the increase of the equivalent permeability of fractures could bring an enhancement of production. Although the flow capacity continues to increase when the equivalent permeability of fracture exceeds a critical threshold, the cumulative gas production curve of the conventional horizontal well case linearly increases. However, there are two phases with different rates (from high to low) in gas production curve of the cases with fractures. Due to the addition of fractures, the gas production rate is at a higher rate in the early stage. Whereas, the gas production rate decreases gradually due to the lack of heat.

With the increasing of gas production, the water production increases simultaneously. The cumulative water volumes are 526, 1500, 2100, and 2200 ST m$^3$ when the permeabilities are $1 \times 10^{-14}, 1 \times 10^{-13}, 1 \times 10^{-12},$ and $1 \times 10^{-11}$ m$^2$, respectively. Comparing with the conventional horizontal cases, the cumulative water volumes of the four cases increase by 1.7, 6.6, 9.6, and 10.1 times, respectively (Figure 12). The water production volumes of all four cases grow at a relatively steady rate. Similarly, the water production volumes increase slightly with the increase of the fracture permeability when the equivalent permeability exceeds the threshold value. The seepage capacity is not the dominant factor in this stage.

4.4.2. CaO Injection Mass. The CaO injection masses are set as 5, 10, 15, and 20 t. The permeability of fractures is set as $1 \times 10^{-14}$ m$^2$ in all four cases. Other initial conditions are consistent with the conventional horizontal well case with fractures. The cumulative methane volumes are 3262, 4254, 5255, and 6221 ST m$^3$ when the CaO injection masses are 5, 10, 15, and 20 t, respectively (Figure 13). Comparing with the conventional horizontal case with fractures, the cumulative methane volumes of injection masses of 5, 10, 15, and 20 t increase by 41.3, 84.3, 127.7, and 169.6%, respectively. Due to the assumption that heat

2308, 6049, 7608, and 7915 ST m$^3$ when the equivalent permeabilities are $1 \times 10^{-14}, 1 \times 10^{-13}, 1 \times 10^{-12},$ and $1 \times 10^{-11}$ m$^2$, respectively. Comparing with the conventional horizontal well case, the cumulative methane volumes of the four cases remarkably increase by 2.8, 8.8, 11.4, and 11.8 times, respectively. The increasing effect of production is obvious. It is remarkable that with the increase of the equivalent permeability, the increasing effect on production is gradually not apparent. When the equivalent permeability of fractures is a relatively small value, the flow capacity of fractures is a key factor for production and the increase of the equivalent permeability of fractures could bring an enhancement of production. Although the flow capacity continues to increase when the equivalent permeability of fracture exceeds a critical threshold, the fluid volumes is limited. Therefore, the increase of the permeability cannot significantly improve production performance when the permeability exceeds the threshold value. In addition, the gas production curve of the conventional horizontal well case linearly increases. However, there are two phases with different rates (from high to low) in gas production curve of the cases with fractures. Due to the addition of fractures, the gas production rate is at a higher rate in the early stage. Whereas, the gas production rate decreases gradually due to the lack of heat.

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supplement is converted to the internal energy of the sediment matrix, the gas production is the same as the conventional horizontal case with fractures in the early stage. Subsequently, there is an obvious acceleration phase in each case with CaO injection. The lasting time of acceleration phase and gas production rate increase with the increase of CaO injection mass. After the heat supplement released from the chemical reaction is consumed by hydrate dissociation, the gas production rate decline to some extent.

The cumulative water volumes are 529, 534, 543, and 555 ST m³ when the CaO injection masses are 5, 10, 15, and 20 t, respectively. Comparing with the conventional horizontal case with fractures, the cumulative water production of injection masses of 5, 10, 15, and 20 t increases slightly (Figure 14). Obviously, the water production tendency and values are close to each other. It indicates that the CaO injection greatly promote the production efficiency. The more injection mass could obtain higher gas production efficiency.

5. CONCLUSIONS

The depressurization and backfilling with in situ supplemental heat method, which combines fluid fracturing and CaO injection, is analyzed by numerical simulation in this work. In order to evaluate the feasibility and efficiency of the novel recovery method, several dynamic evolution characteristics, including the hydrate dissociation behaviors, gas production behaviors, water production behaviors, and the sensitivity analysis of relative parameters, are investigated. The following conclusions could be drawn:

(1) The novel method, i.e., the depressurization and backfilling with in situ supplemental heat method could theoretically enhance the gas production of methane hydrate reservoirs. Based on the numerical setting in this work, the cumulative gas production of the new method is 4.3 times bigger than that of the cases when there is no fracturing and no CaO injection.

(2) The gas production increases with the increasing of the equivalent permeability of fracture. There is a production enhancement of 243% when the permeability increases from $1 \times 10^{-14}$ to $1 \times 10^{-12}$ m². The growth relationship is not as linear as conventional gas reservoirs because the heat supplement is also the restricting factors of gas production and the increasing of the permeability leads larger volume of seawater into production well. Particularly, the increasing of gas production is intensely limited when the equivalent permeability exceeded a threshold value ($1 \times 10^{-12}$ m²).

(3) In contrast to the effect of increasing permeability, increasing CaO injection mass results in a continuous increase in gas production. Based on the numerical results, the CaO injection supplies huge in situ heat. There is a gas production enhancement of 91% and a small water production enhancement of 5% when the permeability increases from 5 to 20 t, which is greatly beneficial to hydrate recovery.

(4) In general, fracturing has positive effects to hydrate recovery. Being different with the fracturing of shale oil/gas reservoirs, the most important aim of the fracturing for hydrate reservoir is the injection of CaO, which is a heat source when CaO reacts with water. Given that the increasing of permeability leads to more water production, the pressure of HBS needs to avoid the connection of fractures and seawater, which poses an even greater challenge to the fracturing process.

In this work, the feasibility of fracturing and CaO injection is not considered. Therefore, the setting of CaO injection mass and the geometry features of fractures are qualitative. The specific process of fracturing and CaO transport will be studied in the following work. The hydrate simulator used in this work is shared on the internet (https://gitee.com/geomech/hydrate).
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The manuscript was written through contributions of all authors. All authors have given approval to the final version of the manuscript. T.X. did the conceptualization, methodology, data curation, and writing of the original draft. Z.Z. did the conceptualization, methodology, software, and validation. S.L. did the conceptualization, methodology, and supervision. X.L. did the conceptualization, formal analysis, and supervision. C.L. did the conceptualization, project administration, and supervision.

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Notes
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