INTRODUCTION

Frac packing involves the simultaneous hydraulic fracturing of a reservoir and the placement of a gravel pack. The fracture is created using a highly viscous fluid, which is pumped at above the fracturing pressure. Screens are in place at the time of pumping. The sand control gravel is placed outside the casing/screen annulus. The aim is to achieve a high-conductivity gravel pack, which is at a sufficient distance from the wellbore, and so to create a conduit for the flow of reservoir fluid.
fluids at lower pressures. Frac-pack technique creates a fracture that prevents formation sand and helps boost production rates, particularly effective in weakly consolidated formations. This combination of sand control and production enhancement has attracted many operators to this technique. For example, more than 65% of sand control completions in the Gulf of Mexico, USA, now use frac-pack systems. In contrast to conventional gravel-packing methods, frac packs provide high-conductivity channels that penetrate deeply into the formation and leave clean undamaged gravel near the wellbore and in the perforations. This ensures that a much larger sand face area is in contact with the completion. In some cases, frac-pack methods may bring skin values down to zero, a wealth of published data suggests that skin values of less than 5 are common. Frac packing avoids many of the productivity issues encountered with conventional cased hole gravel packs. The frac-pack method bypasses formation damage, or skin effects, and creates an external pack around the wellbore. This stabilizes the perforations that are not aligned with the main propped fracture. Frac packing is a mature technique. A thorough review of the technique is given by Ghalambor et al.

Shan et al suggests applying the frac-packing technique to subsea gas hydrate wells for sand control. Hou et al analyzed the technical feasibility of frac-packing wells in marine gas hydrate reservoirs. We investigate in this study the prediction of long-term productivity of frac-packed gas production wells in subsea gas hydrate reservoirs.

The increasing negative impact of heavy fossil energy (coal and crude oil) consumption on human’s life and limited natural gas resources have pushed energy researchers to develop new technologies for producing natural gas from huge offshore gas hydrate deposits. However, the gas production from gas hydrates has not been found in commercial production to date. Early work evaluation of Moridis et al predicted that the gas production rate from a single horizontal gas hydrate well could reach 6.1-33 MMscf per day in the offshore Gulf of Mexico region. Gadditi and Anderson proposed that gas production per well could reach 60-65 MMscf per day. However, this high level of gas production rate has never been verified in the industry.

The Japan Oil, Gas and Metals National Corporation completed two pilot tests of gas production from offshore gas hydrate reservoirs. The total amount of produced natural gas from a well reached 703 Mscf per day on average during the first 6 days of testing period. The well production rate quickly dropped to less than 283 Mscf per day. The well was shut-down after 3 weeks of operation due to sand production, wellbore collapse, and low productivity.

China Geological Survey performed a hydrate gas production test in the South China Sea. The average gas production rate reached 565 Mscf per day during the first 8 days of testing. The production operation continued for 2 months yielding an average gas production rate of 182 Mscf per day. The production operation was terminated due to low productivity of well associated with sand production.

The gas production tests in Japan and China revealed common inter-related problems of sand production, wellbore stability, and low well productivity that hindered the continuation of gas production from offshore gas hydrate deposits and China. The production drawdown required to achieve commercial gas production rates caused wellbore collapse and excessive sand production. The currently used gravel packing completion method is not considered effective in solving the problem.

To reduce production drawdown and mitigate the associated wellbore collapse and sand production problems while still increasing well productivity, new well configurations were proposed recently, which include horizontal snake wells, radial-lateral wells, and frac-packed wells. According to the studies of Wan et al., the horizontal snake well technology can increase the well production rate from 50 MMscf per day to 65 MMscf per day, but it can be very difficult to place snake wellbores in marine gas hydrate reservoirs due to their unconsolidated nature and shallow depth of the gas hydrate zones. Zhang et al proposed to drill radial-lateral wells in gas hydrate reservoirs for enhancing gas production rate. Due to the limited capacity of drilling long laterals, the potential of well productivity improvement is believed to be marginal. Besides, the coiled-tubing drilling technique is required in drilling both horizontal snake wells and radial laterals, which has limitations in horizontal drilling due to a lack of precision and well trajectory control. Hou et al analyzed the technical feasibility of using frac-packed wells for producing natural gas from offshore gas hydrate resources. Their analysis shows that it is technically viable to frac-pack vertical wells in gas hydrate reservoirs for a commercial production rate of greater than 16 MMscf per day. However, they did not present details about the method that they used to predict well productivity of gas hydrate wells.

Gadditi and Anderson conducted a 3D reservoir modeling of the depressurization-induced gas production from gas hydrate reservoirs. Jin et al performed a numerical evaluation of methane production from unconfined gas hydrate-bearing sediment by thermal stimulation and depressurization. These models over-predict the productivity of wells with conventional completion and do not apply to wells with frac-packed completions.

Based on mathematical modeling, Shan et al presented a feasibility study of using frac-packed wells to produce natural gas from subsea gas hydrate resources. Their mathematical model covers the cross-flow from the reservoir to fracture in the fractured region only.

This work reports the new progress made mainly in the following four areas:
1. Shan et al.’s ² model for cross-flow in the fractured region is expanded to cover radial flow in the non-fractured region of the reservoir.
2. The dynamic fracture propagation model given by Hou et al.³ is employed to estimate the propped fracture width.
3. Proppant volume data is used to quantify the fracture radius.
4. Proppant particle size distribution data is utilized to quantify fracture permeability.

Sensitivity analyses were conducted to identify key factors affecting the productivity of frac-packed wells. Case studies were carried out for a gas hydrate well in the Shenhu area, northern South China Sea.

2 | MATHEMATICAL MODELS

This section presents a model for predicting the productivity of frac-packed gas hydrate wells and the analysis of key model parameters including fracture width, fracture radius, and fracture permeability.

2.1 | Well productivity model

Predicting the productivity of gas hydrate wells presents a huge challenge to the petroleum engineers owing to the complexity of mass and heat transfer processes during depressurization. An approximate analytical model was developed in this study for feasibility studies only. The following assumptions are made in the model formulation:

1. The gas hydrate reservoir is homogeneous and isotropic in the horizontal direction. This assumption allows for the analytical modeling of gas flow from the hydrate zone through hydraulic fractures to the wellbore. It is commonly employed by all analytical model developers in the oil and gas industry.
2. The minimum formation stress is in the vertical direction. This assumption is often valid for formations at depths shallower than 3000 ft due to low overburden. This condition is found in many regions including the Daqing Oilfield where horizontal hydraulic fractures were created. Marine gas hydrate reservoirs fall in this category due to their shallow depths below the mud line.
3. The hydraulic fracture takes a circular shape in the horizontal plane at the mid-depth of the hydrate zone Figure 1. This assumption is often valid because hydraulic fracture opens against the minimum formation stress within homogeneous and isotropic formations.
4. Linear vertical flow prevails from the gas hydrate zone to the horizontal fracture in the fractured region, meaning that the horizontal fracture drains gas from the reservoir volumes overlaying and undelaying the fracture in the fractured region.
5. Radial horizontal flow prevails from the non-fractured region to the fractured region Figure 2, meaning that the vertical flow component is negligible in the non-fractured region.

FIGURE 1 Frac-packed horizontal fracture inside a gas hydrate zone
6. The gas hydrate reservoir pressure has dropped below the hydrate dissociation pressure and pseudo-steady state flow condition prevails within the drainage area. This assumption allows for analytical modeling of long-term well productivity under pseudo-steady state flow conditions.

7. Darcy's law dominates the fluid flow in the matrix and fracture. This assumption should be valid in gas hydrate reservoirs due to the low flow velocity of the gas phase caused by the high water saturation in the slow depressurization process.

8. Single phase gas flow can be modeled by Darcy's law with effective gas permeability. This is a common assumption adopted by the analytical modelers in the oil and gas industry to simplify the derivation of analytical models.

9. Complete placement of proppant inside the fracture is achievable by a proper frac-packing design of fracturing parameters. This assumption is supported by previous investigators.

For horizontal radial flow under pseudo-steady state flow conditions, the gas flow rate in the non-fractured region is described by

\[
Q_g = \frac{k_H h (\bar{p}^2 - p_R^2)}{1424 \mu_g c T \left( \ln \frac{c}{R} - \frac{3}{4} \right)}
\]  

where \( Q_g \) is gas production rate in Mscf/d, \( k_H \) is effective horizontal reservoir matrix permeability to gas flow in md, \( h \) is the thickness of gas hydrate reservoir in ft, \( \bar{p} \) is the average reservoir pressure in psia, \( p_R \) is the pressure at the fracture tip in psia, \( \mu_g \) is gas viscosity in cp at the average reservoir pressure, \( z \) is the average gas compressibility factor at the average reservoir pressure, and \( T \) is formation temperature in °R, \( r_e \) is the radius of the drainage area in ft, and \( R \) is the radius of fracture in ft.

The vertical flow from the gas hydrate zone to the fracture is expressed by

\[
Q_g = \frac{k_v R^2 (p_R^2 - p_w^2)}{58.82 \mu_g c T h \left[ 3C R^2 + 2 \left( e^{c (R^2 - r^2)} - e^{- c (R^2 - r^2)} \right) \right] \left( e^{c (R^2 - r^2)} - 1 \right)}
\]  

where \( k_v \) is the effective reservoir vertical permeability in md, \( p_w \) is wellbore pressure in psia and \( r_w \) is wellbore radius in ft, and

\[
C = -\frac{96 k_f}{w_p h k_f}
\]  

where \( w_p \) is the propped fracture width in inch, and \( k_f \) is fracture permeability in md.

Since the fractured region and the non-fractured region are in series for fluid flow, linking the two regions will cover the full flow path from the drainage boundary to the wellbore.
Combining Equations (1) and (3) to link the two regions allows for eliminating $p_R$, which yields

$$Q_g = \frac{k_h h (p_f^2 - p_t^2)}{\mu \varepsilon T} \left\{ 1424 \left( \ln \frac{r_w^2}{R^2} - \frac{3}{4} \right) \right. + \frac{58.824 \rho_L}{\mu \varepsilon T} \left[ 3CR^2 + 2 \left( e^{-z - 2} - e^{-z} \right) \right] \left\} \right\}$$

(4)

2.2 | Key model parameters

2.2.1 | Fracture width

Fracture radius and width are related through the fracturing hydraulics model presented by Hou et al\(^3\) which is summarized as,

$$p_F = p_t + \frac{1.66 \times 10^{-4} f_F \rho_L q_i^2}{w^3} \left( \frac{1}{r_w} - \frac{1}{R} \right)$$

(5)

where $p_F$ is the bottom hole fracturing pressure in psi; $p_t$ is the fracture tip pressure in psi which is assumed to be equal to the minimum formation stress; $f_F$ is the Fanning friction factor; $\rho_L$ is the fluid density in lbm/ft\(^3\); $q_i$ is the injection flow rate during fracturing in bpm, and $w$ is the average fracture width in inch.

Because $R \gg r_w$, $1/R$ is negligible compared to $1/r_w$. Equation (5) implies that the pressure change is essentially controlled by fracture width $w$, not the fracture radius $R$, indicating a choking behavior. Therefore, the average fracture width can be estimated by rearranging Equation (5) as:

$$w = \left[ \frac{1.66 \times 10^{-4} f_F \rho_L q_i^2}{r_w (p_F - p_t)} \right]^{\frac{1}{3}}$$

(6)

The propped fracture width is expressed as

$$w_p = C_p w$$

(7)

where $C_p$ is the overall proppant concentration in the fracturing slurry.

2.2.2 | Fracture radius

The volume of proppant in ft\(^3\) is expressed as:

$$V_p = \frac{\pi R^2 w_p}{12}$$

(8)

This gives

$$R = \sqrt{\frac{12 V_p}{\pi w_p}}$$

(9)

2.2.3 | Fracture permeability

The fracture permeability $k_f$ in Equation (3) can be estimated based on the size distribution of proppant particles.

**FIGURE 3** Relation between grain size and throat size in packs of spherical proppants
The proppant size should be optimized considering the tradeoff between sand control, wellbore/formation stability, and well productivity. Using smaller proppants can improve sand control performance but will scarify fracture conductivity, hindering fluid production at commercial rates. Using larger proppants can enhance fracture conductivity while suffering from issues like sand control and wellbore/formation performance. As illustrated in Figure 3 the throat size of the proppant pack is 1/6.5 times the proppant grain size, i.e., \( d = \frac{D_{g}}{6.5} \) (derivation is available upon request). This relation provides a theoretical base for sizing proppant.

Schwartz\(^1\) developed a correlation for selecting gravel size to control sand based on the uniformity of the formation sand but for most conditions the 40\(^{th}\) weight percentile of gravel is chosen to be 6 times the 40\(^{th}\) weight percentile of the formation sand. Saucier\(^19\) recommended that the proppant diameter be 5-6 times the diameter of the formation sand. Saucier claimed that his technique could maximize proppant pack conductivity by retaining the formation sand at the edge of the proppant pack, which would essentially create an enter-proof screen, rather than building a filter that captured formation sand within the gravel pack. In a tight pack, sand particles smaller than 15% (1/6.5) of the proppant grain diameter are allowed to invade the proppant pack and reduce its effective permeability. Although Saucier’s sizing criteria allows efficient fines filtration, the highly impermeable layer in the proppant pack that is often created at the formation/proppant interface can reduce well productivity. Saucier did not recommend a proppant size distribution. If the uniformity coefficient of proppant is 1.5, Saucier’s correlation gives a minimum proppant size of 0.667 times the 50\(^{th}\) weight percentile of proppant and the maximum proppant size of 1.5 times the 50\(^{th}\) weight percentile of proppant. Jennings\(^20\) showed that using larger proppant in frac-packing could improve well productivity and still effectively control formation sand. The packing of proppant allows some invasion of fines, but most of the fines accumulate within the first few millimeters of the pack and are not allowed to flow through the packed column completely. Jennings\(^20\) work is in line with the filtration theory in which most of the proppant pack (filter) is used to capture contaminants (fines), as opposed to using proppant small enough to preclude the entry of formation particle into the pack.

The mechanical stability of the wellbore and formation is usually associated with the sand production problems, especially in gas hydrate wells.\(^10,11\) Precluding some large size formation into the proppant pack should benefit wellbore/formation mechanical stability. We propose to use the following procedure to select proppant size in this work to mitigate sand control, well productivity, and wellbore/formation stability.

Step 1: Select the maximum permissible proppant size \( D_{\text{MaxP}} \) to preclude large formation sands for wellbore/formation mechanical stability consideration. The \( D_{\text{MaxP}} \) is chosen to be equal to 6.5 times the 10\(^{th}\) weight percentile of formation solid particles so that large particles (top 10%) are kept outside of fracture.

\[
D_{\text{MaxP}} = 6.5d_{10} \quad (10)
\]

Step 2: Select the minimum permissible proppant size \( D_{\text{MinP}} \) to ensure fracture conductivity. The \( D_{\text{MinP}} \) is designed to equal 6.5 times the 90\(^{th}\) weight percentile of formation solid particles which allows trapping at least 90% of formation particles in the proppant pack:

\[
D_{\text{MinP}} = 6.5d_{90} \quad (11)
\]

Although the \( D_{\text{MinP}} \) allows small particles (bottom 10%) to invade into the pack, it is expected that these small particles will be blocked by the formation particles in the proppant pack that are smaller than 6.5 times the smallest particle size. That is, the smallest formation particle of size \( d_{100} \) should be blocked by the formation particles of size \( d < 6.5d_{100} \).

The 50\(^{th}\) weight percentile of proppant particles (\( D_{50} \)) is designed based on the constant uniformity coefficient, which gives

\[
D_{50} = \sqrt{D_{\text{MaxP}}D_{\text{MinP}}} \quad (12)
\]

If measurements of \( D_{10} \) and \( D_{90} \) are not available, they can be estimated by

\[
D_{10} = 0.7D_{\text{MaxP}} \quad (13)
\] and

\[
D_{90} = D_{\text{MinP}}/0.7 \quad (14)
\]

For blocking formation fines defined as particle size \( < 44 \mu m \), the proppant particles with size distribution designed by Equations (10), (11), and (12) may not be available. In these situations, natural sands may be used for the purpose. Permeability damage of the pack by the formation fines is a concern. Estimation of pack permeability can be made using correlations reported in the literature.

Krumbein and Monk\(^21\) measured the permeability of sand packs of 40% porosity for specified size and sorting ranges and developed a correlation relating permeability to the geometric mean of grain diameter and the standard deviation of grain diameter. Beard and Weyl\(^22\) found that Krumbein and Monk’s correlation fits their experimental data fairly well for porosity values ranging from 23% to 43%. The laboratory studies of Krumbein and Monk and Beard and Weyl
were conducted using sieved sands from a common source where grain properties as angularity, sphericity, and surface texture did not vary much. Sorting was purposely controlled to be log-normal. Based on the data from Gulf Coast sands, Morrow et al.\textsuperscript{23} found that permeability was correlated best with the logarithm of grain size times sorting if the fines of size < 44 μm were accounted for. Berg\textsuperscript{24} considered “rectilinear pores,” defined as those pores that penetrate the solid without a change in shape or direction in various packings of spheres and developed a simple correlation:

\[
k_f = 80.8 \varphi^{0.5} D_{50}^2 e^{-1.385P}
\]

where \(k_f\) is permeability in md, \(D\) is particle diameter in micrometers (μm) and \(\varphi\) is fractional porosity. The sorting term \(P\), called the percentile deviation, accounts for the spread in grain size. It takes the form of

\[
P = -\log_2(D_{90}) + \log_2(D_{10}) = 3.32 \log_{10}(D_{10}/D_{90})
\]

Although Berg’s model was derived to estimate the permeability of unconsolidated sand packs with relatively clean consolidated quartz rocks, it gives a good result for sand packs with porosity values < 0.30. Similar correlations were presented by Van Baaren\textsuperscript{25} and Nelson\textsuperscript{26} for consolidated sedimentary rocks.

### 2.3 | Model validation

The new well productivity model was constructed by combining two equations published in peer-reviewed papers. Equation (1) is valid for horizontal radial flow under pseudo-steady state flow conditions. It can be found from many textbooks including the recent one by Guo.\textsuperscript{17} Equation (2) was presented by Shan et al.\textsuperscript{2} for vertical flow from the gas hydrate zone to the fracture. This equation was recently used by Hou et al.\textsuperscript{3} who also presented Equation (6) for estimating fracture width. Equation (15) for predicting fracture permeability was published by Berg.\textsuperscript{24} While validation of these equations is beyond the scope of this work, it is desirable to verify their accuracies with clean field data set in future studies.

### 3 | SENSITIVITY ANALYSIS

Sensitivity analyses were performed to identify major factors affecting well productivity. Data used in the analyses are summarized in Table 1 where the underlined values were utilized when other parameter values were altered. Table 2 presents frac-packing data employed for predicting fracture propped width.

Figure 4 presents the model-calculated fracture radius and gas well production rate. It indicates that the fracture radius and well productivity increase non-linearly with the proppant volume consumed during frac-packing. The production rate 972 Mscf/d at zero proppant volume corresponds to the expected production rate of well with open-hole completion. The rate of increase in fracture radius and well productivity drops as proppant volume increases. The increase in fracture radius slows down due to material balance in the expanding system. The effect of fracture size on well productivity gets less significant in large fractures because of the low pressure drawdown away from the wellbore owing to the choking effect near the wellbore and the pressure loss inside the fracture.

Figure 5 shows the model-calculated gas well production rate versus fracture/proppant volume for reservoir permeability values of 1, 5, and 10 md. A comparison of these three curves implies that well productivity is directly proportional to reservoir permeability when other parameters, such as fracture permeability, are fixed. It is understood that fracture permeability should be designed based on reservoir permeability/grain size, which is discussed in the Case Study section.

Figure 6 illustrates the model-calculated gas well production rate versus fracture/proppant volume for fracture permeability values of 1000, 3000, and 5000 md. A comparison of these three curves shows that well productivity increases as fracture permeability increases. The increase in fracture permeability slows down due to material balance in the expanding system. The effect of fracture size on well productivity gets less significant in large fractures because of the low pressure drawdown away from the wellbore owing to the choking effect near the wellbore and the pressure loss inside the fracture.
of these three curves indicates that the benefit of increasing fracture permeability diminishes when the fracture permeability is greater than 3000 md. This is explained as a result of flow inside the reservoir being the limiting step due to low reservoir permeability.

4 | CASE STUDY

The gas hydrate deposits in the Shenhu area, northern South China Sea, are under a seawater depth of about 3870 ft. The hydrate-bearing layer extends from 510 to 580 ft interval below the seafloor. The pressure gradient in the seawater is 0.465 psi/ft. The average reservoir pressure is estimated to be 2053 psia based on the normal pressure gradient 0.465 psi/ft and depth 4415 ft.

Li reported the first production test on a gas hydrate well in the Shenhu area. The reservoir lithology is clayey silt in three intervals. The mean effective porosity within interval "a" is 35%, the mean hydrate saturation is 34%, and the mean permeability is 2.9 md. The mean effective porosity of interval "b" is 33%, the mean hydrate saturation is 31%, and the mean permeability is 1.5 md. The mean effective porosity of interval "c" is 32%, mean gas saturation is 7.8%, and the mean permeability is 7.4 md.

The fracture-tip pressure is assumed to equal the minimum formation stress which is the vertical stress for the shallow deposit. The vertical stress is calculated based on
the pressure gradient of 0.456 psi/ft above the mud line and the overburden stress gradient 1.0 psi/ft below the mud line. Therefore, the minimum formation stress at the mid-zone depth of 4415 ft is calculated to be 2345 psi.

Figure 7 presents an approximate size distribution of formation solid particles collected from the gas hydrate zone. The maximum particle size is only 29 μm, which is characterized as formation fines. The chart gives $d_{10} = 14 \mu m$, $d_{50} = 8.5 \mu m$, and $d_{90} = 5 \mu m$.

The size distribution of sand/proppant can be selected using the formation fines size distribution data.

$$D_{maxP} = 6.5 (14) = 91 \mu m$$
$$D_{minP} = 6.5 (5) = 33 \mu m$$

Figure 6  Effect of fracture permeability on well productivity

$$D_{50} = \sqrt{(91)(33)} = 54 \mu m$$
$$D_{10} = 0.7 (91) = 64 \mu m$$
$$D_{90} = (33) /0.7 = 46 \mu m$$

$$P = 3.32\log_{10} \left( \frac{64}{46} \right) = 0.46$$

Assuming a reasonable value for a sand pack porosity of 0.40, the fracture permeability is estimated to be

$$k_f = 80.8 (0.4)^{5.1} (54)^2 e^{-1.385(0.46)} = 1187 \text{ md}$$
Table 3 provides a summary of the best estimate of reservoir parameters based on the analysis of gas hydrate samples from the site SH7 of GMGS-1 and GMGS-3 in the Shenhu area. The propped fracture width was estimated using assumed frac-packing data shown in Table 4.

Figure 8 presents the model-calculated fracture radius and gas well production rate. The production rate 254 Mscf/d at zero proppant volume corresponds to the expected production rate of well with open-hole completion. A gas production rate $Q_g = 10$ Mscf/d, given by a fracture $R = 45$ ft created by a proppant volume $110$ ft$^3$ is considered a commercial-level production rate.

The target gas hydrate zone of the Shenhu site has an unconsolidated setting consisting of soft silt. There exists high uncertainty in the determination of reservoir properties. Table 5 presents a range of reservoir properties covering possible conditions in the Shenhu field.

Figure 9 demonstrates model-calculated well productivity curves with the reservoir properties taken from the three intervals. They vary greatly due to high heterogeneity. Reliable prediction of the well productivity should consider which interval is frac-packed and the thickness of the fractured interval.

It is a great interest to compare the productivities of frac-packed wells, gravel-packed wells, and screen-packed wells. Suppose a well is gravel-packed or screen-packed in a 15” open hole. Setting the proppant volume to zero in the well model allows for predicting well productivity of gravel-packed or screen-packed wells without completion skin. Figure 10 shows predicted productivity curves with a wellbore diameter of 15”. The predicted well productivity values at zero proppant volume are 283 Mscf/d, 129 Mscf/d, and 789 Mscf/d for reservoir properties of Intervals “a”, “b”, and “c”, respectively. These production rate values are similar to the production rate values of a 7-7/8” ($r_w = 0.328$ ft) frac-packed hole with only 1.2 ft$^3$ proppant.

5 CONCLUSIONS

The productivity of frac-packed wells in marine gas hydrate reservoirs was investigated in this study. The work focuses on long-term well productivity under pseudo-steady state flow conditions after gas hydrate reservoir pressure drops to below the hydrate dissociation pressure within the well drainage area.
Shan et al.\textsuperscript{2} analytical model for cross-flow in the fractured region was modified in this study to integrate the horizontal radial flow in the non-fractured region of the well drainage area. Methods have been developed to predict propped fracture geometry (thickness and radius) and design proppant size distribution for formation sand/particle control. Sensitivity analyses were performed to identify key factors affecting the productivity of frac-packed wells. Case studies were carried out for the gas hydrate deposits in the Shenhu area, northern South China Sea. The following conclusions are drawn.

1. Frac-packing can significantly improve the productivity of gas hydrate wells. Fracture radius and well productivity increase non-linearly with the proppant volume consumed during frac-packing. The rates of increase in fracture radius and well productivity drop as proppant volume increases. The increase in fracture radius slows

| TABLE 5 | Reservoir properties of three intervals in the Shenhu field |
|-------|-----------------|
| Interval "a" | Interval "b" | Interval "c" |
| $d_{10}$ ($\mu$m) | 14.00 | 11.70 | 28.14 |
| $d_{50}$ ($\mu$m) | 8.49  | 7.10  | 17.06 |
| $d_{90}$ ($\mu$m) | 5.00  | 4.18  | 10.05 |
| Porosity | 0.35  | 0.33  | 0.32  |
| Permeability (md) | 2.90  | 1.50  | 7.40  |

FIGURE 9 Model-predicted effect of formation property on well productivity

FIGURE 10 Model-predicted effect of formation property on the productivity of 15° hole
down due to material balance in the expanding system. The effect of fracture size on well productivity gets less significant in large fractures because of the choking effect near the wellbore and the low pressure-drawdown away from the wellbore owing to the pressure loss inside the fracture.

2. The model-predicted productivity of frac-packed wells is directly proportional to reservoir permeability. This results from the assumption of Darcy’s flow in low-permeability reservoirs where gas velocity is low in the matrix during model development. However, this assumption needs further validation.

3. The productivity of frac-packed wells increases non-linearly with fracture permeability. The benefit of increasing fracture permeability diminishes when the fracture permeability is greater than 3000 md in the case study. This is explained as the result of the gas flow inside the reservoir being the limiting step due to low reservoir permeability.

4. Gas hydrate wells in the Shenhu area, northern South China Sea, can be elevated to commercial levels of greater than 10 MMscf/day with a proppant injection volume of 110 cubic feet. The well productivity will further increase with injected proppant volume.

5. This work developed an analytical model for frac-packed well productivity. It is expectedly valid for gas hydrate wells under pseudo-steady state flow conditions after gas hydrate reservoir pressure drops to below the hydrate dissociation pressure within the well drainage area. The model needs to be verified with field data or numerical simulation in the future.

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NOMENCLATURE

\( C \) group defined by Equation (3)

\( c \) compressibility in 1/psi

\( C_p \) proppant concentration in fraction

\( D_g \) grain diameter in μm

\( D_{max P} \) maximum permissible proppant diameter in μm

\( D_{min P} \) minimum permissible proppant diameter in μm

\( D_{10} \) 10th weight percentile of proppant

\( D_{50} \) 50th weight percentile of proppant

\( D_{90} \) 90th weight percentile of proppant

\( d_t \) throat diameter in μm

\( d_{10} \) 10th weight percentile of particles

\( d_{50} \) 50th weight percentile of particles

\( d_{90} \) 90th weight percentile of particles

\( e \) base of natural logarithm

\( f_F \) Fanning friction factor

\( h \) thickness of gas hydrate reservoir in ft

\( k_f \) fracture permeability in md

\( k_H \) matrix horizontal permeability in md

\( k_V \) matrix vertical permeability in md

\( P \) defined by Equation (16)

\( \bar{p} \) average reservoir pressure in psia

\( p_e \) pressure at the no-flow boundary in psia

\( p_F \) wellbore fracturing pressure in psia

\( p_t \) fracture tip pressure in psia

\( p_w \) wellbore pressure in psia

\( q_i \) injection rate in bpm

\( Q_g \) total gas production rate of a gas well in gas hydrate conditions in Mscf/d

\( R \) radius of the fracture in ft

\( r_w \) wellbore radius ift

\( T \) formation temperature in °F

\( w \) average fracture width in inch

\( w_p \) propped fracture width in inch

\( V_p \) the volume of sand/proppant

\( z_{\text{gas}} \) gas compressibility factor

\( \rho_L \) fluid density in lbm/ft³

\( \mu_g \) gas viscosity in cp

\( \sigma_{\text{max}} \) maximum stress in psi

\( \sigma_{\text{min}} \) minimum stress in psi

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