A feasibility study of using frac-packed wells to produce natural gas from subsea gas hydrate resources

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Abstract
Frac-packing is an attractive technique to stimulate production for gas hydrate reservoirs with the additional benefit of solving the problematic sand production problems. So far, there have been no documented mathematical models to predict the propagation of fractures and to forecast gas production for frac-packed gas wells. An analytical model was derived to predict the propagation of a horizontal fracture and to assess the well productivity in frac-packed gas wells in a gas hydrate reservoir. The model assumes a steady, single-gas, Darcy flow in the matrix and fracture. Case analyses were performed for key design and operational parameters with the analytical model. The result shows that it is easy to control the relationship between the wellbore fracturing pressure and injecting flow rate, and thus, fractures of any length can be produced in the fracture penetration process of frac-packed wells. Case analysis also shows that the gas production rate increases nonlinearly with the fracture propagation and increases linearly with the fracture width. The increase in fracture width turns out to be surprisingly effective in improving well productivity without threshold within the investigated range of width. It was also found that the increase in fracture permeability contributes more to the productivity of the frac-packed wells than the increase in matrix permeability. The model also assumes no flow at the boundary of the reservoir, which may underestimate those gas hydrate reservoirs with pressure supply. This work uses a theoretical approach to estimate the productivity of the frac-packed gas hydrate reservoirs, which may benefit in solving the sand production issue during the production process as well.

KEYWORDS
frac-packing, gas hydrate, gas production, well productivity

1 | INTRODUCTION

Natural gas hydrates (NGHs) are ice-like crystalline compounds that consist of gas (i.e., methane, ethane, and propane) and hydrogen trapped among water molecules under specific pressure and temperature conditions.1 Since the 1960s, researchers have unearthed many NGHs distributed worldwide. NGHs deposits typically exist in the marine and permafrost sediments,2,3 partially found in onshore lakes and deep waters,4 continental margin sediments,5 seabed,6 and polar sediments.7 According to field exploitation trials8-10 and resource assessment technologies,11 estimates on the
amount of gas hydrates are approximately $3 \times 10^{15} \text{ m}^3$. If these natural gas reserves in NGHs can be harvested safely, cheaply and efficiently, gas hydrates may become a potential alternative energy of coal and oil to meet the ever-growing global demands.13

To recover this resource, researchers are mainly focusing on four methods: depressurization, thermal stimulation, chemical injection, and a combined method. The depressurization operation is carried out by declining the pressure in NGHs reservoir below the pressure of the hydrate decomposition.9,14-16 The thermal stimulation involves rising temperature under external heat like hot water, hot brine, steam, or an electromagnetic heat source to keep the temperature in the NGHs reservoir above the hydration temperature at an equilibrium condition 17-20. The chemical injection is used to thermodynamically destabilize the natural conditions of the NGHs formations by shifting the equilibrium curve to higher pressures and lower temperatures.21-24 The combined method is to integrate the depressurization method, thermal stimulation, and chemical injection.25-27 These methods all involve destabilizing the hydrate and separating the gas from the compound.

These methods mentioned above have been applied in field trials to explore the potential for commercial gas flow.28 Such field trials have been taking place globally such as the Alaska North Slope,29,30 the Messoyakha gas field in the Arctic,31 the South Syncline of the Juhugeng mine in the north of the Qinghai-Tibet Plateau permafrost32,33 and the Shenhua area34-37 in China, the Daini-Atsumi Knoll area of the eastern Nankai Trough 38 in Japan and Canada’s Mackenzie Arctic,31 the South Syncline of the Juhugeng mine in the north of the Qinghai-Tibet Plateau permafrost32,33 and the Shenhua area34-37 in China, the Daini-Atsumi Knoll area of the eastern Nankai Trough 38 in Japan and Canada’s Mackenzie Arctic.31 An economic flow of gas was generally achieved by depressurization stimulation for these hydrate reservoirs, where gas dominates the flow. This sheds light on the assumption made in the proposed theoretical model in which gas dominates the flow in the reservoir.

In the hydrate production process, sand production is an unavoidable issue due to the poor consolidation of NGHs formations.40,41 It has become one of the key risks that limit the effective development of hydrate reservoirs.10,42,43 It was reported that gas production was stopped due to the problematic sand production.10,44,45 Stand-alone screens 46 and gravel packing 47 were introduced to prevent the sand particles from moving into the wellbore to deal with the sand production problem while producing gas from gas hydrates. Both theoretical methods and numerical simulation have been used to determine proper gravel properties.41,45,48,49 However, the frac-packing technique has not been introduced to control the sand production in gas hydrate reservoirs. The frac-packing is a completion technique that combines hydraulic fracturing and gravel packing. Special fracturing treatment combined with gravel packing can produce highly conductive fractures to support cracks that can control grain migration, maximize sand placement, and assist steady gas flow.50 Industrial cases have shown that frac-packing operations can reliably address both the sand-control problem and provide effective production stimulation for unconsolidated reservoirs.51-54 According to Hainey and Troncoso,52 fracturing tests were conducted for two wells (A10 and D9) which were unable to produce prior to the treatment in the South Pass Block 61 Field. The frac-pack techniques had resulted in 200–300 BPD in oil production on natural flow (A10) and 130 BPD in oil production (D9). The use of larger gravel packs had contributed to better control of sand production. Liu et al 53 presented frac-pack design treatments in the offshore Bohai field in China. The production data showed sustained oil production of above 50BPD in multiple wells and all wells were produced with no sand. The frac-packing technique has been continuously improved over time with lessons learned from field practices. A review done by Weirich et al 54 based on 600 frac-packing jobs has shown that this methodology has been gradually improved to pack the holes more efficiently and safely. The frac-packing method for sand-control operation was presented by Shell in Germany51 and subsequently succeeded in other areas such as, the Middle East, Indonesia, Brazil, West Africa, and the North Sea.55 Generally, field practices in literature have demonstrated that the frac-packing is an attractive technique for both improving oil and gas production and solving the sand production issue.

During the frac-packing treatment of gas hydrate reservoirs, it is critical to know how the fractures will be generated and propagated in the reservoir in order to design frac-pack treatment and forecast production. No literature has been found to disclose any method to assess the fracture propagation of frac-packed wells to produce natural gas from gas hydrate resources. In this paper, analytical models were developed to predict the propagation of a horizontal fracture and sensitivity analysis is conducted to evaluate different fracturing parameters on the productivity of frac-packed gas wells in a gas hydrate reservoir.

## 2 | MATHEMATICAL MODEL

### 2.1 | Fracture propagation in frac-packing

Horizontal cracks are generated when the formation stress in the vertical direction is less than the stress in the horizontal direction.56 Vertical wells can be drilled to create the horizontal hydraulic fractures for improving the productivity of oil and gas wells. A frac-pack hydraulic model was derived for predicting the fracture propagation based on the following assumptions:

1. It is assumed that the horizontal fractures are pin-shaped in the oil and gas industry.
2. The formation of dissociated gas hydrate is highly permeable and unconsolidated.
3. The reserve of natural gas can be produced steadily.
4. The fracture permeability is dependent on its width.
5. The hydrate formation stress in the vertical direction is less than the stress in the horizontal direction.

The derivation of the model is detailed in Appendix A. Resultant equations are summarized in this section.

The pressure distribution in the fracture at a radial distance \( r \) is described as

\[
p_f = p_i + \frac{1.66 \times 10^{-4} f_e \rho_1 q_i^2}{w^3} \left( \frac{1}{r_w} - \frac{1}{r} \right),
\]

(1)

where \( p_f \) is the fracturing pressure in the wellbore, psi; \( p_i \) is the pressure at the fracture tip, psi; \( r \) is the fracture propagation radius, ft; \( r_w \) is the wellbore radius, ft; \( f_e \) is the Fanning friction factor; \( \rho_1 \) is the fluid density, lbm/ft³; \( q_i \) is the injection rate, bpm; and \( w \) is the average fracture width, inch, which can be estimated using the following equation \(^57\):

\[
w = 0.85 \left[ \frac{\mu q_i (1 - \nu) R_f}{E} \right]^{0.25},
\]

(2)

where \( \mu \) is the fluid viscosity, cp; \( \nu \) is the Poisson’s ratio of rock; \( R_f \) is the radius of the fracture, ft; and \( E \) is Young’s modulus, psi.

### 2.2 Well productivity

An analytical model was derived to predict the productivity of frac-packed gas wells under pseudo–steady-state flow conditions. The following assumptions are made in this model:

1. The gas hydrate reservoir is isotropic.
2. Pseudo–steady-state flow condition is reached within the well drainage area.
3. Linear flow prevails from the reservoir to the fracture.
4. Darcy’s law dominates the fluid flow in the matrix and fractures.
5. Fracture skin is negligible.
6. A hydraulic fracture is in the horizontal plane within the drainage area.
7. Single gas-phase flow in a gas hydrate reservoir.

The derivation of the model is detailed in Appendix B. Resultant equations are summarized in this section.

The gas flow rate in the US field unit is

\[
Q_g = \frac{3.76 \times 10^{-4} k_m R^2 \left( p^2 - p_w^2 \right)}{3(T + 460) \mu h \left[ 3C R^2 + 2 \left( e^{\frac{\zeta}{R} (R^2 - r^2)} - e^{-\frac{\zeta}{R} R^2} \right) \right]} \left[ e^{\frac{\zeta}{R} (R^2 - r^2)} - 1 \right].
\]

(3)

where \( Q_g \) is the total gas production rate. Mscf/d; \( k_m \) is the matrix permeability, mD; \( R \) is the radius of the gas hydrate reservoir; \( h \) is the thickness of the gas hydrate reservoir, ft; \( p \) is the average reservoir pressure, psia; \( z \) is the gas compressibility factor, and \( T \) is the formation temperature in °F.

\[
C = \frac{96 k_m}{w h k_t},
\]

(4)

where \( k_t \) is the permeability of the fracture, mD.

The average reservoir pressure is given by Equation 5.

\[
p = p_e + \frac{2 (p_e - p_w)}{3C R^2} \left( e^{\frac{\zeta}{R} (R^2 - r^2)} - e^{-\frac{\zeta}{R} R^2} \right),
\]

(5)

where \( p_e \) is the pressure at the no-flow boundary, psi.

The equation for pressure distribution in the fracture is expressed as

\[
p_f(r) = p_e - \left( p_e - p_w \right) e^{\frac{\zeta}{R} (R^2 - r^2)},
\]

(6)

where \( p_f(r) \) is the pressure in the fracture at a radial distance of \( r \) from the wellbore.

### 3 CASE ANALYSIS

This section presents a case analysis for producing natural gas from gas hydrate wells. The productivity index \( J_g \) is calculated as

\[
J_g = \frac{Q_g}{p - p_w} = \frac{3.76 \times 10^{-4} k_m R^2 \left( p^2 + p_w^2 \right)}{z (T + 460) \mu h \left[ 3C R^2 + 2 \left( e^{\frac{\zeta}{R} (R^2 - r^2)} - e^{-\frac{\zeta}{R} R^2} \right) \right]} \left[ e^{\frac{\zeta}{R} (R^2 - r^2)} - 1 \right].
\]

(7)

Equation 7 indicates that the well productivity index is inversely proportional to fluid viscosity. The effects of the fracture propagation, fracture width, rock permeability, fracture permeability, and the flow rate will be investigated with sensitivity analysis. These parameters were studied using the basic reservoir properties from the site SH7 of GMGS-1 and GMGS-3 in the Shenhu area, the South China Sea.\(^{58,59}\) These study areas are dominated by methane hydrate, and in some areas, they are almost pure methane hydrate (99.2%).\(^{60}\) The properties of the hydrate deposit and the initial conditions of mathematical models used in the analysis are shown in Table 1.

The depth of the seafloor at this site is 1108 m. The hydrate-bearing layer extends from 155 to 177 m below the seafloor. The pressure gradient in the seawater is 0.465 psia/ft. The pressure gradient below the seafloor is
1.0 psia/ft. Therefore, the pressure at the fracture tip $p_t$ is 2198.88 psia, and the average reservoir pressure $p$ is 1926.82 psia. The gas compressibility factor $z$ based on the Brill and Beggs correlation is 0.7115. The gas viscosity $\mu$ with the correlation of Carr, Kobayashi, and Burrows is 0.017 cp.

### 3.1 Effect of injection rate

The effect of the fluid injection rate on the wellbore fracturing pressure was calculated using Equation 1 assuming a fracture length of 1000 ft. The result in Figure 1 shows that the well fracturing pressure increases slightly as the injecting flow rate increases. This means that the wellbore fracturing pressure is easily obtainable and controllable, and fractures of any desired length can be produced as needed in the fracture propagation process of frac-packed wells without excessively high injection pressure.

### 3.2 Effect of fracture propagation

The effect of fracture penetration on well productivity index $J_g$ was calculated using Equation 7. The result in Figure 2 shows that the productivity of the gas well increases noticeably from 1.85 Mscf/d-psi to 3.5 Mscf/d-psi as the fracture penetration increases from 10 to 35 ft from the wellbore, and the rate of increase gradually decreases. The improvement in $J_g$ can be attributed to the increased contact area to the reservoir rock as the fracture propagates deeper into the formation, which exposes more gas from the reservoir matrix to the fracture. As the fracture penetration continues to increase above 35 ft up to 100 ft, $J_g$ only increases slightly from 3.5 Mscf/d-psi and remains below 3.6 Mscf/d-psi. The plateau of $J_g$ with the increasing fracture penetration could be attributed to the increasing average drainage distance of gas to the wellbore and the increasing friction due to the increasing distance as the fracture grows. Figure 2 also indicates an optimal fracture depth beyond which the well productivity will no longer benefit from creating deeper fractures. This optimal fracture penetration can be determined using the analytical model presented here. However, although deeper fractures do not contribute to the further increase in well productivity on the surface, it will help maintain the steady gas deliverability of the well over the long run due to the larger stimulated reservoir volume by the fractures.

### 3.3 Effect of fracture width

The effect of fracture width on well productivity index was calculated by Equation 7. The result in Figure 3 shows that well productivity increases linearly with the increase in fracture width. For frac-packed wells, increasing the fracture width can contribute directly to the increase in fracture conductivity and thus well productivity. By calculating the

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**TABLE 1** Properties of the hydrate deposit and initial conditions of mathematical models

| Property                              | Value         |
|---------------------------------------|---------------|
| Wellbore radius ($r_w$)               | 0.328 ft      |
| Reservoir thickness ($h$)             | 72.179 ft     |
| Reservoir temperature ($T$)           | 57.47 °F      |
| Effective gas permeability in matrix ($k_m$) | 75 mD         |
| Effective gas permeability in fracture ($k_f$) | 20,000 mD    |
| Fracture penetration ($\Delta R$)     | 500 ft        |
| Fracture width ($w$)                  | 0.25 in       |
| Fluid density ($\rho_L$)              | 70 lbm/ft$^3$ |
| Fanning friction factor ($f_F$)       | 0.01          |
| Average reservoir pressure            | 1926.82 psi   |
| Wellbore pressure ($p_w$)             | 1500 psi      |

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![Figure 1](image1.png)  
**Figure 1** Effect of injection rate on fracturing pressure

![Figure 2](image2.png)  
**Figure 2** Effect of fracture propagation on well productivity
slope of the line in Figure 3, we found that a 0.1 inch of increase in fracture width can result in an improvement around 1.4 Mscf/d-psi in $J_g$. Increasing the fracture width of frac-packed wells is found to be very effective in increasing well productivity based on the proposed model. This impact of fracture width on productivity may be attributed to the increase in the cross-sectional flow area, which increases the flow rate of gas. The increase in fracture width may also decrease the friction for gas flow with the increased area of flow.

3.4 Effect of matrix permeability

The effect of matrix permeability on well productivity was calculated with Equation 7. The result in Figure 4 shows that the productivity of the frac-packed well first increases and then remains stable as the matrix permeability increases. The improvement in $J_g$ with the increasing matrix permeability is still marginal, and the trend of $J_g$ versus matrix permeability only happens within a small range of productivity index. Figure 4 shows that the $J_g$ increases only slightly from 3.538 to 3.573 Mscf/d-psi when the matrix permeability increases from 1md to 80md. For frac-packed wells, the matrix permeability of the formations does not seem to affect the ultimate well productivity much. On the other hand, the effect of fracture permeability on $J_g$ shown below turned out to be greater than that of the matrix permeability.

3.5 Effect of fracture permeability

The effect of fracture permeability on well productivity was calculated with Equation 7. The result in Figure 5 shows that the well productivity increases linearly with the increasing fracture permeability. An increase of 10 000 mD in fracture permeability can result in a 1.79 Mscf/d-psi increase in well productivity from calculating the slope of the curve in Figure 5. This is an expected result since the increase in fracture permeability improves the fracture conductivity and thus contributes to higher well productivity, like the case of fracture width. The relationship between $J_g$ and fracture permeability may provide a hint as to how the type of sands used in the hydraulic fractures may affect the well production performance.

3.6 Effect of pressure drawdown

Pressure drawdown is a critical operational parameter in gas production. The effect of pressure drawdown on the productivity index and production rate is calculated using the derived model shown in Figure 6 and Figure 7, respectively. Figure 6 shows that the productivity index decreases linearly with the increase in pressure drawdown. This is understandable from Equation 7, which shows the relationship between...
J and bottom hole pressure. Figure 7 shows the production rate calculated with the corresponding $J_g$ and pressure drawdown. The gas production rate keeps increasing but the incremental production rate decreases with the increasing pressure drawdown. The operation drawdown can be determined using Nodal analysis, which will not be further discussed in this paper.

4 | DISCUSSION

The well productivity model was derived for gas production in a gas hydrate reservoir where the gas hydrates in the fractured region have decomposed into gas and water. This model is not valid for early production conditions before gas hydrates are dissociated. The model may overestimate the well productivity at the early time gas production.

The well productivity model accounts for only the vertical flow of fluid toward the circular fracture. The converging flow in the horizontal direction toward the fractured area is neglected. This simplification is conservative for the prediction of well productivity. The result given by the model may underestimate the well productivity under steady-state flow.

Equation 1 shows that the relationship involves the fracture penetration distance $r$. Since the practical dimension of the fracture penetration is much greater than the wellbore radius $r_w$, the term $1/r$ in the equation is always negligible. Therefore, it is not recommended that this equation be used to calculate fracture penetration that can result in an unacceptable error. The fracture penetration and fracture width in the productivity equation should be determined by the volume of proppant injected during the frac-packing.

5 | CONCLUSIONS

An analytical model was derived in this work to predict the propagation of a horizontal fracture and to evaluate the productivity of frac-packed gas wells in a gas hydrate reservoir. Case analyses were performed with the analytical model, which may provide practical approaches to the design of fracturing parameters or $J_g$ prediction. Future work may consider more boundary scenarios such as steady-state flow to address the production forecast and fracturing design for the gas hydrate reservoirs with constant pressure supply. The following conclusions are drawn based on our analysis:

1. The analytical model shows that it is easy to control the relationship between the wellbore fracturing pressure and the injection rate. Wellbore fracturing pressure is easily obtainable and controllable; thus, fractures of any length can be produced in the fracture propagation process of frac-packed wells without excessive injection pressures.
2. It is found that there is an optimal fracture penetration depth beyond which the well productivity will no longer increase, albeit marginally, with the increasing penetration depth. The fracture penetration can be identified with the proposed model.
3. The productivity of frac-packed wells can directly benefit from increasing the fracture width and fracture permeability, and $J_g$ increases in a linear pattern with each of these two factors.
4. The matrix permeability does affect the well $J_g$ but only marginally. The improvement in $J_g$ is on a decimal level when the matrix permeability increases by magnitude.

5.1 | Unit conversion factor

The unit conversion factors are provided below to the convert Darcy unit to the US field unit. Darcy units can be converted to SI unit easily.
Volumetric gas flow rate:
\[ Q \left( \text{cm}^3/\text{s} \right) = 326.99 \times \left( \text{cm}^3/\text{s} / (\text{Mcf}/\text{d}) \right) \times Q \left( \text{Mcf}/\text{d} \right). \]

Matrix permeability: \( k_m \left( \text{D} \right) = 10^{-2} \text{D}/\text{md} \cdot k_m \left( \text{md} \right). \)

Fracture permeability: \( k_f \left( \text{D} \right) = 10^{-3} \text{D}/\text{md} \cdot k_f \left( \text{md} \right). \)

Fracture penetration: \( R \left( \text{cm} \right) = 30.49 \text{cm}/\text{ft} \cdot R \left( \text{ft} \right). \)

Pressure: \( p \left( \text{atm} \right) = 0.068 \text{atm/psi} \cdot p \left( \text{psi} \right). \)

Fracture width: \( w \left( \text{cm} \right) = 2.54 \text{cm}/\text{inch} \cdot w \left( \text{inch} \right). \)

Viscosity: \( \mu \left( \text{cp} \right) = \mu \left( \text{cp} \right). \)

Compressibility: \( c_i \left( \text{atm}^{-1} \right) = 14.7 \text{atm}^{-1} / \text{psi}^{-1} \cdot c_i \left( \text{psi}^{-1} \right). \)

Injection rate during fracturing:
\[ q \left( \text{m}^3/\text{s} \right) = 0.00265 \times \left( \text{m}^3/\text{s} / (\text{bpm}) \right) \cdot q \left( \text{bpm} \right). \]

Fluid density:
\[ \rho \left( \text{kg/m}^3 \right) = 16.019 \times \left( \text{kg/m}^3 / (\text{lbm/ft}^3) \right) \cdot \rho \left( \text{lbm/ft}^3 \right). \]

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NOMENCLATURE
\( c \quad \) Compressibility coefficient
\( E \quad \) Young's modulus in psi
\( f_F \quad \) Fanning friction factor
\( g \quad \) Gravitational acceleration factor (32.17 lbm-ft/lb-fs²)
\( h \quad \) Thickness of gas hydrate reservoir in ft
\( K \quad \) Consistency index in cp
\( k_f \quad \) Effective gas permeability in the fracture in md
\( k_m \quad \) Effective gas permeability in the matrix in md
\( P \quad \) Pressure in psia
\( p_d \quad \) Pressure drawdown in psia
\( p_e \quad \) Pressure at the no-flow boundary in psia
\( p_f \quad \) Pressure in the fracture in psia
\( p_f \quad \) Wellbore fracturing pressure in psia
\( p_t \quad \) The fracture tip pressure in psia
\( p_w \quad \) The wellbore pressure in psia
\( q \quad \) The flow rate in the fracture in bpm
\( q_t \quad \) The injection rate in bpm
\( Q \quad \) Gas production rate in ft³/s
\( Q_F \quad \) Fracture flow rate in ft³/s
\( Q_g \quad \) Total gas production rate of a gas well in gas hydrate conditions in Mcf/d
\( r \quad \) Fracture propagation radius in ft
\( R \quad \) Radius of gas hydrate reservoir in ft
\( R_f \quad \) Radius of the fracture in ft
\( r_w \quad \) Wellbore radius in ft
\( T \quad \) Formation temperature in °F
\( v \quad \) Velocity in the direction perpendicular to the fracture in ft/s
\( V \quad \) Fluid in a volume element in ft³
\( v \quad \) Superficial gas velocity in ft/s
\( v_f \quad \) Velocity of fluid in the fracture in ft/s

\( w \quad \) Average fracture width in inch
\( z \quad \) Gas compressibility factor

Greeks
\( \rho_L \quad \) Fluid density in lbm/ft³
\( \mu \quad \) Gas viscosity in cp
\( \nu \quad \) Poisson's ratio
\( \varphi \quad \) Reservoir porosity

Subscripts
\( f \quad \) Fracture
\( sc \quad \) Standard condition

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APPENDIX A

Derivation of mathematical model for propagation of a horizontal fracture in frac-packed gas well in a gas hydrate reservoir

This section provides a derivation of the analytical model for predicting the propagation of a horizontal fracture in frac-packed gas wells in a gas hydrate reservoir.

Assumptions

The formation of dissociated gas hydrate is highly permeable and unconsolidated. The reserve of natural gas can be produced steadily. The fracture permeability is dependent on its width. The hydrate formation stress in the vertical direction is less than the stress in the horizontal direction.

Governing equation

A radial flow through a volume element in a horizontal fracture is depicted in Figure A1.

Hydraulics gives the following relation:

$$dp = -\frac{2f_F \rho_L}{g w} v^2 dr$$  \hspace{1cm} (A1)

where $p$ is the pressure in lbm/ft$^2$; $f_F$ is the Fanning friction factor; $\rho_L$ is the fluid density in lbm/ft$^3$; $g$ is the gravitational acceleration factor (32.17 lbm-ft/lbm-s$^2$); $v$ is the velocity of fluid (or the fracture propagation rate) in ft/s; $r$ is the fracture propagation radius in ft; and $w$ is the average fracture width in ft.\footnote{Dorf RC. The Engineering Handbook. Baca Baton: CRC Press; 1995:1026-1027.}

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The average fracture width may be estimated by the equation presented by Geertsma & de Klerk 57 for radial fractures. If the fracturing fluid is injected into only one fracture, the injection rate \( q_i \) is expressed as

\[
q_i = 2\pi vw r d\theta = 2\pi vw r \
\]

which gives

\[
v = \frac{q_i}{2\pi wr}. \
\]

Substituting Equation A3 into Equation A1 gives

\[
dp = -\frac{fFrLq_i^2}{2\pi^2 gw^3 r^2}dr \quad (A4) 
\]

Integration of Equation A4 gives

\[
\int \frac{p_t}{p_w} dr = -\frac{fFrLq_i^2}{2\pi^2 gw^3 r^2}dr \quad (A5) 
\]

or

\[
p_F = p_t + \frac{fFrLq_i^2}{2\pi^2 gw^3} \left( \frac{1}{r_w} - \frac{1}{r} \right) \quad (A6) 
\]

**Unit conversion**

The equations derived above are only valid for US engineering units. US oilfield units are used in hydraulic fracturing design where pressure is in psi, flow rate in bpm, fracture width in inch, and distance in feet. Equation A7 expresses Equation A6 in US field units,

\[
p_F = p_t + 1.66 \times 10^{-4} fFrLq_i^2 \left( \frac{1}{r_w} - \frac{1}{r} \right) \quad (A7) 
\]

**APPENDIX B**

**Derivation of a mathematical model for predicting the productivity of frac-packed gas well in a gas hydrate reservoir**

This section provides a derivation of an analytical model for predicting the productivity of frac-packed gas wells under pseudo–steady-state flow conditions.

**Assumptions**

The following assumptions are made in this model:

1. The gas hydrate reservoir is isotropic.
2. Pseudo–steady-state flow condition is reached within the well drainage area.
3. Linear flow prevails from the reservoir to the fracture.
4. Darcy’s law dominates the fluid flow in the matrix and fractures.
5. Fracture skin is negligible.
6. A hydraulic fracture is in the horizontal plane within the drainage area.
7. Single gas-phase flow in a gas hydrate reservoir.

**Governing equation**

A schematic of a fluid flowing from a reservoir layer to a packed fracture is shown in Figure B1. The productivity of one fracture can be formulated based on the linear flow from the shaded body of the reservoir to the fracture.

Under pseudo–steady-state flow conditions, compressible fluids migrate by the expansion owing to depressurization. The volumetric element \( V \) of a fluid can be expressed as

\[
V = \frac{\varphi h}{2} r dr d\theta. \quad (B1) 
\]

The definition of the compression coefficient gives

\[
v = \frac{q_i}{2\pi wr}. 
\]
\[
c = -\frac{1}{V} \left( \frac{\partial V}{\partial p} \right) \quad (B2)
\]

Differentiation of Equation B1 with respect to time gives an expression of the flow rate from the volume \( V \):

\[
cV \frac{\partial p}{\partial t} = -\frac{\partial V}{\partial t} = -dq(r) \quad (B3)
\]

where \( q(r) \) is an elementary production unit with a height of \( \frac{h}{2} \), a thickness of \( dr \) and width of \( rd \).

The pressure decline rate \( \frac{\partial p}{\partial t} \) in Equation B3 is then expressed using Equation B1 as

\[
\frac{\partial p}{\partial t} = -\frac{dq(r)}{cV} = -\frac{2dq(r)}{c\varphi hr \theta dr}. \quad (B4)
\]

If \( dq(r) \) is replaced by \( dQ(r) \) around the circle of \( 2\pi \) radians, this equation is then is written as

\[
\frac{\partial p}{\partial t} = -\frac{dQ(r)}{\pi c\varphi hr dr}. \quad (B5)
\]

where \( Q(r) \) is the elementary circular production unit with a thickness of \( dr \), a perimeter of \( 2\pi r \) and a height of \( \frac{h}{2} \).

The following equation governs the linear flow to the fracture:

\[
\frac{\partial^2 p}{\partial y^2} = \frac{\varphi \mu c}{k_m} \frac{\partial p}{\partial t} \quad (B6)
\]

where \( y \) is the vertical direction of the reservoir.

Substituting Equation B5 into Equation B6 yields:

\[
\frac{\partial^2 p}{\partial y^2} = -\frac{\mu dQ(r)}{\pi k_m h r \theta dr} \quad (B7)
\]

Integrating Equation B7 one-time yields:

\[
\frac{\partial p}{\partial y} = -\frac{\mu dQ(r)}{\pi k_m h r \theta dr} y + C_1 \quad (B8)
\]

where \( C_1 \) is an integration constant and can be determined using the no-flow boundary condition

\[
\left( \frac{\partial p}{\partial y} \right)_{y=h/2} = 0. \quad (B9)
\]

Applying Equation B9 to Equation B8 gives:

\[
C_1 = \frac{\mu dQ(r)}{2\pi k_m r \theta dr} \quad (B10)
\]

Substituting Equation B10 into Equation B8 yields

\[
\frac{\partial p}{\partial y} = \frac{\mu dQ(r)}{\pi k_m h r \theta dr} \left( \frac{1}{2} - \frac{y}{h} \right) \quad (B11)
\]

Separating the variables, Equation B11 is changed to

\[
\int dp = \int \frac{\mu dQ(r)}{\pi k_m r \theta dr} \left( \frac{1}{2} - \frac{y}{h} \right) dy + C_2 \quad (B12)
\]

Integration of Equation B12 gives

\[
p = \frac{\mu dQ(r)}{\pi k_m r \theta dr} \left( \frac{y}{2} - \frac{y^2}{2h} \right) + C_2 \quad (B13)
\]

where the integration constant \( C_2 \) can be determined using the boundary condition at the fracture face

\[
p|_{y=0} = p_i(r) \quad (B14)
\]

where \( p_i(r) \) is the pressure in the fracture at a radial distance of \( r \) from the wellbore. Applying Equation B14 to Equation B13 gives

\[
C_2 = p_i(r) \quad (B15)
\]

Substituting Equation B15 into Equation B13 gives

\[
p = \frac{\mu dQ(r)}{\pi k_m r \theta dr} \left( \frac{y}{2} - \frac{y^2}{2h} \right) + p_i(r) \quad (B16)
\]

Along the no-flow boundary \( y = \frac{h}{2} \) where the pressure is \( p_e \), Equation B16 demands

\[
dQ(r) = \frac{8\pi k_m r \theta dr}{\mu h} \left[ p_e - p_i(r) \right] \quad (B17)
\]

The Darcy velocity in the matrix along the \( y \)-axis at the fracture face at a radial distance \( r \) can thus be expressed as

\[
v(r) = \frac{dQ(r)}{2\pi r \theta dr} = \frac{4k_m}{\mu h} \left[ p_e - p_i(r) \right] \quad (B18)
\]

The cumulative flow rate of fluid collected from the two faces of the fracture ring between the fracture tip and a radial distance \( r \) can be determined as

\[
Q(r) = \frac{16\pi k_m r}{\mu h} \left[ p_e - p_i(r) \right] dr \quad (B19)
\]

If the average fracture width is \( w \), the Darcy velocity in the fracture can be formulated by dividing Equation B19 by the cross-sectional area of the fracture:
\[ v_f(r) = \frac{Q(r)}{2\pi rw}. \quad (B20) \]

Applying Darcy’s law to the flow along the fracture gives
\[ v_f(r) = -\frac{k_t}{\mu} \frac{dp_f(r)}{dr} \quad (B21) \]

Coupling Equations (B20) and (B21) yields
\[ \frac{Q(r)}{2\pi rw} = -\frac{k_t}{\mu} \frac{dp_f(r)}{dr} \quad (B22) \]

Substituting Equation B19 into Equation B22 and rearranging the latter gives
\[ \int_r^R \frac{16\pi k_m r}{whk_t} \left[ p_e - p_f(r) \right] dr = -2\pi rw \frac{k_t}{\mu} \frac{dp_f(r)}{dr} \quad (B23) \]

Differentiation of Equation B23 with respect to \( r \) yields
\[ \frac{8k_m r}{whk_t} \left[ p_e - p_f(r) \right] = \frac{dp_f(r)}{dr} + r \frac{d^2p_f(r)}{dr^2} \quad (B24) \]

Defining \( p_d(r) \) as the pressure drawdown at point \( r \) in the fracture
\[ p_d(r) = p_e - p_f(r) \quad (B26) \]

Equation B25 becomes
\[ C r p_d(r) = \frac{dp_d(r)}{dr} \quad (B27) \]

and \( C \) is expressed in Darcy unit as
\[ C = -\frac{8k_m}{whk_t} \quad (B28) \]

Equation B27 is integrated to obtain
\[ \frac{C}{2} r^2 = \ln p_d(r) + C_3 \quad (B29) \]

The boundary condition is expressed as
\[ p_d(r)|_{r=r_w} = p_e^* = p_e - p_w \quad (B30) \]

Applying this boundary condition to (B29) gives
\[ C_3 = \frac{C}{2} r_w^2 - \ln p_d^* \quad (B31) \]

Substituting Equation B31 into Equation B29 results in
\[ p_d(r) = p_d^* e^{\xi(r^2 - r_w^2)} \quad (B32) \]

Substitution of Equation B26 into Equation B32 gives the pressure drawdown distribution in the fracture:
\[ p_e - p_f(r) = (p_e - p_w) e^{\xi(r^2 - r_w^2)} \quad (B33) \]

The equation for pressure distribution in the fracture is then expressed as
\[ p_f(r) = p_e - (p_e - p_w) e^{\xi(r^2 - r_w^2)} \quad (B34) \]

To obtain an influx function of a closed-form, substituting Equation B33 into Equation B19 yields
\[ Q(r) = \int_r^R \frac{16\pi k_m r}{wh} \left[ p_e - p_w \right] e^{\xi(r^2 - r_w^2)} dr \quad (B35) \]

which is
\[ Q(r) = \frac{16\pi k_m}{wh} \left( p_e - p_w \right) \int_r^R e^{\xi(r^2 - r_w^2)} dr \quad (B36) \]

The integration part in the equation B36 can be calculated as
\[ \int_r^R e^{\xi(r^2 - r_w^2)} dr = \frac{1}{C} \left[ e^{\xi(r^2 - r_w^2)} - e^{\xi(r^4 - r_w^4)} \right] \quad (B37) \]

The following inflow performance relationship for the fracture is obtained
\[ Q_e = Q(r_w) = \frac{16\pi k_m}{whC} \left( p_e - p_w \right) \left[ e^{\xi(r^2 - r_w^2)} - e^{\xi(r^4 - r_w^4)} \right] \quad (B38) \]

Substituting Equation B37 and Equation B34 into Equation B16 gives an expression for pressure distribution in the matrix,
\[ p = p_e - (p_e - p_w) e^{\xi(r^2 - r_w^2)} \left[ 1 - 8 \left( \frac{y}{h} - \frac{y^2}{h^2} \right) \right] \quad (B39) \]
The average reservoir pressure, \( \bar{p} \), may be taken as the pressure in the matrix weighted by volume shown in Equation B40. The pressure in the fractures is neglected owing to its small volume.

\[
\bar{p} = \frac{n \rho dV}{dn} = \frac{2\varphi \int_0^R \rho 2\pi r dr}{\pi R^2 h \varphi} \quad (B40)
\]

Substituting Equation B39 into Equation B40 and integrating the later yield

\[
\bar{p} = \frac{2\varphi (p_e - p_w)}{3CR^2} \left( \frac{\xi (s^2 - z^2)}{s} - \frac{\xi z}{s} \right) \quad (B41)
\]

Rearranging Equation B42 for \( p_e \), we have

\[
p_e = \bar{p} + \frac{2\varphi (p_e - p_w)}{3CR^2} \left( \frac{\xi (s^2 - z^2)}{s} - \frac{\xi z}{s} \right) \quad (B42)
\]

Substituting Equation B43 into Equation B38 results in

\[
Q_V = \frac{48\pi k_m R^2 (\bar{p} - p_w)}{\mu h} \left[ \frac{\xi (s^2 - z^2)}{s} - \frac{\xi z}{s} \right] \quad (B43)
\]

where \( C = -\frac{8k_m}{whk_j} \).

**Unit conversion**

Equation B43 is a general inflow equation in Darcy units for wells with any single-phase fluid flow inside the reservoir.

For gas wells, the flow rate in Equation B43 is converted to surface condition using the real gas law:

\[
\frac{\left( \bar{p} + p_w \right)}{2} \frac{Q_V}{\xi T} = \frac{p_w}{z_w T_w} \quad (B44)
\]

Substituting \( p_w = 14.696 \) psia, \( z_w = 1.0 \), \( T_w = 520 \) °R, and \( Q_{sc} \) in Mscf/d into this equation gives:

\[
Q_{sc} = \frac{0.01769 \left( \bar{p} + p_w \right) Q_V}{\xi T} \quad (B45)
\]

Substituting Equation B43 into Equation B45 and we have

\[
Q_{sc} = \frac{0.01769 \left( \bar{p} + p_w \right)}{\xi T} \frac{48\pi k_m R^2 (\bar{p} - p_w)}{\mu h} \left[ \frac{\xi (s^2 - z^2)}{s} - \frac{\xi z}{s} \right] \left[ \frac{\xi (s^2 - z^2)}{s} - 1 \right] \quad (B46)
\]

Substituting the unit conversion coefficients into the gas inflow rate expression, the gas flow rate in US field units becomes

\[
\frac{3.76 \times 10^{-4} k_m R^2 (\bar{p} - p_w)}{z(T + 460)\mu h} \left[ \frac{\xi (s^2 - z^2)}{s} - \frac{\xi z}{s} \right] \left[ \frac{\xi (s^2 - z^2)}{s} - 1 \right] \quad (B47)
\]

where \( C = -\frac{96k_m}{whk_j} \).