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Explicit original gas in place determination of naturally fractured reservoirs in gas well rate decline analysis

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Abstract:
Naturally fractured gas reservoirs have contributed significantly to global gas reserves and production. The classical gas-well decline analysis relies largely on Arps' empirical decline models, or modern production decline analysis associating with pseudo-variables. The explicit original gas in place determination methodology is extended from homogeneous reservoir to naturally fractured reservoir under constant or variable bottom-hole pressure conditions in gas-well rate decline analysis. Then, the relationship between gas flow rate and average reservoir pseudo-pressure in the boundary-dominated flow period is re-derived. This formula is in the same format with the equation for homogeneous reservoir by due to the introduction of a new productivity index parameter that captures the inter-porosity flow between fracture and matrix in the natural fractured reservoir. The proposed step-by-step procedures are applied here, which enable the estimation of decline exponent and the explicit and straightforward determination of the original gas in place without any iterative calculations. Four simulated cases prove that our methodology can be successfully used in heterogeneous naturally fractured reservoirs with irregular boundary under constant or variable bottom-hole pressure conditions.

1. Introduction

Firstly introduced by Arps (1945), rate decline analysis has become a commonly used technique for the interpretation of available well production data, estimation of reservoir parameters, and forecast of well production performance. It is generally assumed in the industry that the value of decline exponent empirically remains constant with time. Fetkovich (1980) later comprehensively explored the analytical solutions by Arps with a more rigorous theoretical log-log type-curve plot. Carter (1985) improved Fetkovich's type-curves for gas reservoir analysis by coupling the variation in gas viscosity and compressibility during reservoir depletion. He defined the "viscosity-compressibility ratio" to quantify the impact of pressure draw-down and changing gas viscosity-compressibility performance. Largely relying on the introduction of pseudo-functions, the techniques targeted for oil wells can be successfully applied in gas wells. The pseudo-pressure function was firstly proposed by Al-Hussainy et al. (1966). Fraim and Wattenbarger (1987) introduced the concept of pseudo-time to gas well decline analysis based on the definition first presented by Agarwal (1979). Wattenbarger et al. (1998) derived the solutions of linear flow into fractured wells and introduced type curves for rate decline analysis. Duong (2011) presented an empirical method to predict the flow rate and estimated the ultimate recovery for fracture-dominated wells in unconventional reservoirs by introducing four empirical constants. The implementation of pseudo-functions effectively and successfully linearizes the gas diffusivity equation, and entails the transformation of pressure and time data before use in type-curve analysis (Wang et al., 2021; Benson and Clarkson, 2022). However, the calculation of pseudo-time requires the prior knowledge of original gas in place (OGIP), which involves iterative procedures (Blasingame

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and Lee, 1988; Blasingame et al., 1991; Zaremoayedi et al., 2022).

The naturally fractured reservoir is a heterogeneous system that consists of two porous systems: fracture and matrix. In general, fractures are highly permeable and account for a small percentage of the total reservoir volume, while matrices have low permeability but larger storage capacity (Kao et al., 2022; Chen et al., 2023). Barenblatt et al. (1960) firstly proposed a dual-porosity model for liquid using the inter-porosity flow equation and the diffusivity equation for the fracture system. Warren and Root (1963) used this method to analyze the testing data of oil wells by assuming an array of identical and rectangular parallelepiped matrix blocks in an anisotropic reservoir. Prat et al. (1981) derived an analytical solution for a dual-porosity oil well producing under constant bottom-hole pressure (BHP) condition using Warren and Root's model in a radial system. Pseudo-time has been defined to incorporate the water saturation and compressibility by Gerami et al. (2007) to study dual-porosity systems; however, increasing error is obtained when comparing the analytical results against those from CMG. Meng et al. (2020) presented a simple and quick well-testing model for a multi-fractured horizontal well with non-uniform fractures. Pi et al. (2023) studied the coupling mechanisms of oil-water displacement and imbibition in tight reservoirs while considering the inter-porosity flow in the pore-fracture system. Andersen (2023) pointed out that the effect of boundary-dominated flow on diffusion problems can be explained in terms of changes in the self-similar behavior at the open boundary. Qin et al. (2023) presented a non-intrusive embedded discrete fracture model while considering complex fracture networks.

Overall, the current gas rate decline analysis methods are mainly divided into the following four categories: (1) empirical analysis methods, including those by Arps (1945), Duong (2011) decline analysis, and so on; (2) modern production decline analysis methods, initiated by Blasingame et al. (1991), Wattenbarger et al. (1998), and comprehensive studies in the past decades; (3) the material balance combined with the boundary-dominated flow method, represented by Palacio and Blasingame (1993); (4) explicit rate decline analysis based on Arps' method, represented by Stumpf and Ayala (2016) and Wang and Ayala (2020). Stumpf and Ayala (2016) demonstrated that the decline exponent employed in Arps' hyperbolic decline model can be rigorously estimated before collecting any field data. This value is only the function of gas pressure-volume-temperature (PVT) properties and the prevailing constant BHP for volumetric, single-phase gas reservoirs. Subsequently, Wang and Ayala (2020) extended that work from constant BHP to a more realistic variable BHP condition, and demonstrated that the variable BHP hyperbolic decline exponents become solely dependent on gas PVT properties and take the possible largest value compared with constant BHP production.

In this study, the theoretical basis is presented by applying the work of Stumpf and Ayala (2016) and Wang and Ayala (2020) for naturally fractured reservoirs, and it is shown that the gas flow rate versus pseudo-pressure relation of constant or variable BHP dual-porosity systems are consistent with those for homogeneous reservoirs by introducing a new productivity index value. The step-by-step procedures presented by Stumpf and Ayala (2016) and Wang and Ayala (2020) are rigorously applied in naturally fractured reservoirs with irregular outer boundaries, and are validated by four simulated cases.

2. Methodology

2.1 Gas flow rate vs. pseudo-average pressure for naturally fractured reservoir

A single gas well is assumed to produced under the boundary-dominated flow period. The gas flow obeys Darcy's law both in the fracture and the matrix systems. For the circular reservoir, the generalized diffusivity equation in the fracture for a dual-porosity system is:

$$-\frac{1}{r}\frac{\partial}{\partial r}\left(r\rho_f v_r\right)=\frac{\partial\left(\phi_f\rho_f\right)}{\partial t}+\frac{\partial\left(\phi_m\rho_m\right)}{\partial t} \tag{1}$$

The generalized equation of state shows that:

$$\rho=\frac{pM}{ZRT} \tag{2}$$

The pseudo-pressure function was firstly defined by Al-Hussainy et al. (1966):

$$m(p)=2\int_0^p\frac{p}{\mu_g Z}\mathrm{dp}=2\theta\int_0^p\frac{1}{\mu_g c_g}\mathrm{d}p \tag{3}$$

where r denotes radial coordinate; ρ denotes gas density; ρ_f and ρ_m are gas densities in the fracture and matrix, respectively; v_r denotes gas flow rate in the fracture; ϕ_f and ϕ_m represent the fracture and matrix porosities, respectively; t denotes time; p denotes pressure; M denotes molecular weight, Z denotes deviation factor; R denotes universal gas constant; T denotes temperature; μ_g denotes gas viscosity; c_g denotes gas isothermal compressibility; $m(p)$ denotes pseudo-pressure; θ is a constant, which can be calculated as a function of universal gas constant (R), temperature (T), and molecular weight (M):

$$\theta=\frac{RT}{M} \tag{4}$$

It is assumed that the gas flow in the fracture obeys to Darcy's law. Substituting Eq. (2) into Eq. (1) and then applying the definition of pseudo-pressure in Eq. (3) yields:

$$\frac{\mathrm{MW}k_f}{2RT}\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial m(\rho_f)}{\partial r}\right)=\frac{\partial(\phi_f\rho_f+\phi_m\rho_m)}{\partial t} \tag{5}$$

We introduce the closed outer boundary condition for boundary-dominated flow (BDF):

$$\left.\frac{\partial m(p_f)}{\partial r}\right|_{r=r_e}=0 \tag{6}$$

Multiplying both sides with reservoir volume, integrating from an arbitrary radius to outer radius, and applying the outer boundary condition in Eq. (6) yields:

$$m(p_f)-m(p_{wf})=\frac{p_{sc}q_{Gsc}T}{\pi hk_f T_{sc}}\left(\ln\frac{r}{r_w}-\frac{r^2}{2r_e^2}\right) \tag{7}$$

where k_f denotes fracture permeability; r_e denotes outer boundary radius; r_w denotes wellbore radius; p_{sc} denotes pressure at the standard condition; T_{sc} denotes temperature at the standard condition; h denotes formation thickness; p_f denotes pressure in the fracture; p_{wf} denotes BHP; q_{Gsc} denotes gas flow rate; $m(p_f)$ denotes the fracture pseudo-pressure; $m(p_{wf})$ denotes the pseudo-BHP. Considering the skin factor S in Eq. (7) yields:

$$m(p_f)-m(p_{wf})=\frac{P_{sc}q_{Gsc}T}{\pi hk_fT_{sc}}\left(\ln\frac{r}{r_w}-\frac{r^2}{2r_e^2}+S\right) \tag{8}$$

Alternatively, Eq. (8) can be rewritten in terms of average pseudo-pressure, which is defined as:

$$\begin{aligned}\overline{m}(p_f)&=\frac{\iiint_v m(p_f)\mathrm{d}V}{V}\\&=\int_0^h\int_0^{2\pi}\int_{r_w}^{r_e}m(p_f)r\mathrm{d}r\mathrm{d}\varphi\mathrm{d}z\\&=\frac{2}{r_e^2}\int_{r_w}^{r_e}m(p_f)r\mathrm{d}r\end{aligned} \tag{9}$$

Substituting the Eq. (8) into Eq. (9) yields:

$$q_{Gsc}=\frac{\pi k_fhT_{sc}}{P_{sc}T\left(\ln\frac{r_e}{r_w}-\frac{3}{4}+S\right)}\left[\overline{m}(p_f)-m(p_{wf})\right] \tag{10}$$

By introducing the pseudo-steady component $b_{D,pss}$, the gas rate equation in pseudo-pressure form under BDF can be applied in any reservoir geometries, such as:

$$q_{Gsc}=\frac{\pi k_fh}{\rho_{sc}\theta b_{D,pss}}\left[\overline{m}(p_f)-m(p_{wf})\right] \tag{11}$$

where V denotes volume; $b_{D,pss}$ denotes pseudosteady-state component; $\overline{m}(p_f)$ denotes the average fracture pseudo-pressure.

Eq. (11) is valid for gas BDF, regardless of whether the production scenario is under constant or variable BHP conditions. Zhang et al. (2018) compared the numerical production results and the production for 118 different dual-porosity models, and the exact match in BDF for all cases were obtained. However, Eq. (11) gives the gas rate with the average fracture pseudo-pressure, which is difficult to determine from the reservoir parameters and production data. A technique to transfer the average fracture pseudo-pressure to the predictable average reservoir pseudo-pressure in BDF was rigorously developed by Zhang et al. (2018). The representation of average fracture pseudo-pressure ($\overline{m}(p_f)$) in the average matrix pseudo-pressure ($\overline{m}(p_m)$) and pseudo BHP ($m(p_{wf})$) is:

$$\overline{m}(p_m)=\frac{1}{1+K}\overline{m}(p_m)+\frac{K}{1+K}\overline{m}(p_{wf}) \tag{12}$$

where

$$K=\frac{2\pi k_fh}{\delta k_mV_{res}b_{D,pss}} \tag{13}$$

Substituting Eq. (12) into Eq. (11) and canceling the $\overline{m}(p_f)$ term gives:

$$q_{Gsc}=J[m(p)-m(p_{wf})] \tag{14}$$

with

$$J=\frac{\pi k_fh}{\rho_{sc}\delta b_{D,pss}(1+K)} \tag{15}$$

where p_m denotes pressure in the matrix; δ is a shape factor; k_m denotes matrix permeability; V_{res} represents reservoir volume; J is productivity index, which is generally considered as a constant in BDF.

2.2 The Arps-Based explicit OGIP determination method

Arps' classical hyperbolic decline analysis assumes that the decline exponent is a constant, and it has been considered to be rigorously only applicable to the constant BHP condition, with the equation expressed as (Arps, 1945):

$$q_{Gsc}=\frac{q_{Gi}}{(1+bD_it)^{1/b}} \tag{16}$$

where q_{Gi} denotes initial flow rate; b denotes gas rate decline exponent; D_i denotes initial decline rate in the hyperbolic model. Pichit et al. (2015) demonstrated that even though the gas rate decline exponent is changing during the development process, it still preserves a "nearly-constant-b" period at the early stage of BDF, which was validated later by Jongkittinarukorn et al. (2021, 2023). Stumpf and Ayala (2016) thus defined this period as "hyperbolic window" for a constant BHP situation. Subsequently, Wang and Ayala (2020) found that the approximately hyperbolic decline prevails during the entire BDF period under variable BHP condition. They assumed that BHP is being adjusted in a way to keep pace with the declining reservoir pressure as $m(p_{wf})=\gamma\cdot m(p)$ (γ is an arbitrary constant number), and demonstrated that under such condition of Arps' hyperbolic decline equations, which had been previously considered applicable only to a constant BHP situation, can be rigorously applied for analyzing the variable BHP production in gas wells. Starting from the gas flow rate equation in Eq. (14) , the equations of gas decline rate and decline exponent for a fractured reservoir can be rigorously derived for constant and variable BHP conditions following the methods presented by Stumpf and Ayala (2016), and Wang and Ayala (2020). Table 1 compares the parameters for homogeneous and fractured reservoir. It is found that the gas flow rate equation for naturally fractured reservoir has the same format with the homogeneous reservoir established by Palacio and Blasingame (1993) via introducing a new productivity index parameter that captures the inter-porosity flow between fracture and matrix in a natural fractured reservoir. This new productivity index considers the influence of complex flow in a natural fractured formation under any reservoir geometry. In addition, the decline rate of fractured reservoir is different from that of homogenous reservoir considering the influences of natural fractures.

Integrating the expression of decline exponent in the last line of Table 1 on both sides yields the average value of "b"-denoted as "b_i":

$$b_i=\begin{cases}\overline{\alpha}r_{mi} & \text{constant} \quad \text{BHP}\\ \overline{\alpha} & \text{variable} \quad \text{BHP}\end{cases} \tag{17}$$

with

Table 1. Comparison of gas rate decline parameters for homogeneous and fractured reservoirs.

Parameters	Constant BHP		Variable BHP	
	Homogeneous	Fractured	Homogeneous	Fractured
q_{Gsc}	$J[m(p)-m(p_{wf})]$			
J	$\frac{\pi kh}{\rho_{sc}\delta b_{D,pss}}$	$\frac{\pi k_f h}{\rho_{sc}\delta b_{D,pss}(1+K)}$	$\frac{\pi kh}{\rho_{sc}\delta b_{D,pss}}$	$\frac{\pi k_f h}{\rho_{sc}\delta b_{D,pss}(1+K)}$
D_i	$\frac{2\pi k}{A\phi b_{D,pss}\mu_{gi}c_{gi}}$	$\frac{2\pi k_f}{A\phi b_{D,pss}\mu_{gi}c_{gi}(1+K)}$	$\frac{2\pi k(1-\gamma)}{A\phi b_{D,pss}\mu_{gi}c_{gi}}$	$\frac{2\pi k_f(1-\gamma)}{A\phi b_{D,pss}\mu_{gi}c_{gi}(1+K)}$
b	$\alpha(p)r_m$		$\alpha(p)$	

Notes: $\gamma = m(p_{wf})/m(p)$, which is assumed as a constant.

$$\begin{aligned}\overline{\alpha} &= \frac{1}{m(p_i)-m(p_{wf})}\int_{m(p_{wf})}^{m(p_i)}\alpha(p)\mathrm{d}m \\ &= -\frac{1}{m(p_i)-m(p_{wf})}\int_{m(p_{wf})}^{m(p_i)}\frac{\mathrm{d}\lg(\mu_g c_g)}{\mathrm{d}\lg(m(p))}\mathrm{d}m\end{aligned} \tag{18}$$

$$r_m = \frac{m(p)-m(p_{wf})}{m(p)} \tag{19}$$

where p_i denotes initial pressure; $m(p_i)$ denotes pseudo initial pressure; r_{mi} denotes the r_m at initial pressure condition. Eq. (17) shows that the gas rate decline exponent can be predicted explicitly and uniquely before any field data is collected, rather than an empirical parameter that is matched by rate-time data. It should be noted that the actual gas decline exponent and b_i for a naturally fractured reservoir are not the same as that for a homogeneous reservoir, even though they share similar mathematical expressions because the reservoir pressure changes differently in the existence of fractures. The following equation can be derived according to the cumulative production rate for hyperbolic decline, that is, the initial gas flow rate under hyperbolic decline, and the expressions of D_i in Table 1 are:

$$\left(\frac{q_{Gsc}}{q_{Gi}}\right)^{1-b_i} = 1 - \frac{G_p^*}{OGIP} \tag{20}$$

where

$$G_p^* = \begin{cases}\dfrac{2p_i(1-b_i)}{\mu_{gi}c_{gi}m(p_i)r_{mi}}G_p & \text{constant} \quad \text{BHP} \\ \dfrac{2p_i(1-b_i)}{\mu_{gi}c_{gi}m(p_i)}G_p & \text{variable} \quad \text{BHP}\end{cases} \tag{21}$$

where μ_{gi} and c_{gi} represent the gas viscosity and gas isothermal compressibility under the initial conditions, respectively; G_p denotes cumulative gas production. Since b_i can be determined in advance, there is only one unknown parameter (OGIP) left if the reservoir pressure, temperature and gas specific gravity is given from Eqs. (20)-(21). Therefore, the step-by-step analysis procedures are presented below:

- Step I: The gas viscosity, compressibility factor, and isothermal compressibility are firstly evaluated on the basis of correlations with reservoir pressure, temperature and specific gravity.
- Step II: The constant b_i value is determined based on its definition in Eq. (17) for specific BHP conditions.
- Step III: The $q_{Gsc}^{1-b_i}$ is plotted versus G_p^* in a rectangular coordinate system, and the OGIP is determined from the x-intercept.

In this way, the explicit and straightforward determination of OGIP can be successfully extended from homogenous to natural fractured gas reservoir, thus avoiding the iterative calculation of pseudo-variables. Importantly, the reservoir pressure is assumed to be unchanged (or changed very little) when the boundary-dominated flow is achieved in this methodology. This is true for radial flow but not for linear flow. Pichit et al. (2015) pointed out that the gas boundary-dominated linear flow starts only after the reservoir is heavily depleted by extensive reservoir simulations. Therefore, it may lead to erroneous results if it is directly applied to linear gas flow (Wang et al., 2021).

It is necessary to note that the OGIP originally denotes the total quantity (volume) of natural gas contained in a "subsurface" asset prior to production. Meanwhile, in the gas rate decline analysis, it refers to the dynamic gas reserve that the pressure propagates to. In the actual gas reservoir development, only a proportion of gas can be possibly extracted. In general, the abandonment pressure or flow rate is needed to achieve the estimated ultimate recovery.

3. Case studies

Four simulated cases are discussed in this part, each depicting a different depletion or outer boundary conditions. In Casess #1 and #2, the gas wells produce in constant and variable BHP cases, respectively, under the circular closed outer boundary conditions. Then, these cases are extended to a more realistic irregular outer boundary condition, which are shown in Cases #3 and #4. Reservoir heterogeneity is considered, and the formation porosity and permeability are set to follow the normal distribution in the above analysis. The average porosity equals to 0.2 and the average permeability equals to 5 mD. In addition, the natural fractures are set to randomly distributed in the reservoir with a permeability of 100 mD.

3.1 Case #1

The schematic of the gas reservoir for the first case is shown in Fig. 1. The gas well is designed to deplete under constant BHP condition of 3,000 psia from an initial pressure

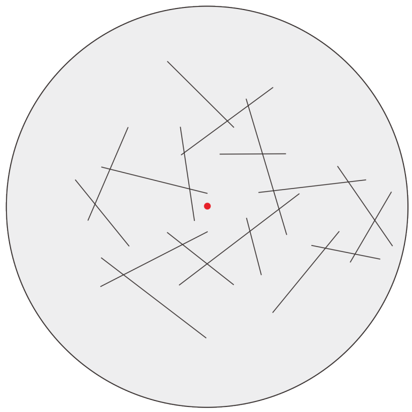

Fig. 1. Schematic of the gas reservoir for Cases #1 and #2.

Table 2. Inputs for Case #1.

Property	Value
Initial pressure (psia)	5,000
Bottom-hole pressure (psia)	3,000
Reservoir temperature (°F)	240
Gas specific gravity	0.55
Reservoir outer radius (ft)	1,000
Wellbore radius (ft)	0.25
Average matrix permeability (mD)	5
Fracture permeability (mD)	100
Average porosity	0.2
Pay thickness (ft)	100

of 5,000 psia. The circular outer boundary is considered with the radius of 1,000 ft. Other parameters are provided in Table 2. On the basis of the input data, the OGIP is accurately calculated as equal to 15.28 BSF according to the volumetric method.

The gas properties are firstly calculated based on the standard natural gas correlations. In this study, the gas compressibility factors are obtained from the Dranchuk and Abou-Kassem correlation (Dranchuck and Abou-Kassem, 1975), the gas viscosity is calculated based on the Lee et al. (1966), the gas isothermal compressibilities are estimated after Abou-Kassem et al. (1990), and the pseudo-properties are calculated on the basis of Sutton (1985). The parameter b_i can be calculated directly on the basis of its definition shown in Eq. (23) , where the r_{mi} should be obtained first from the initial pressure and BHP values:

$$r_{mi}=\frac{1.3355\times10^{9}-5.5588\times10^{8}}{1.3355\times10^{9}}=0.5838 \tag{22}$$

$$b_i=\overline{\alpha}r_{mi}=0.6304\times0.5838=0.368 \tag{23}$$

Then, G_p^* is calculated first according to Eq. (21) as the x coordinate, while $q_{Gsc}^{1-b_i}$ is estimated as the y coordinate. The OGIP is straightforwardly obtained by extrapolating the straight line to the x coordinate (Fig. 2). In this case, the OGIP is determined to be 14.7 BSF, which has an error of 3.8% compared with the known value.

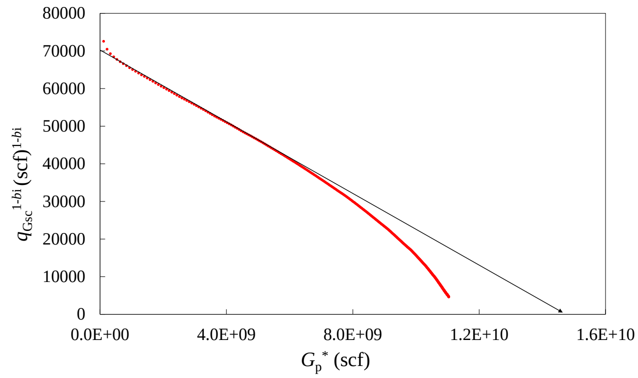

Fig. 2. Straight-line analysis for Case #1.

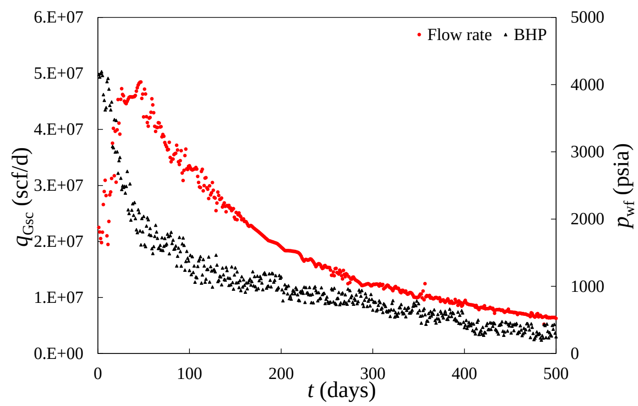

Fig. 3. Production history for Case #2.

3.2 Case #2

This case is simulated under the variable BHP condition. All the input parameters, including the reservoir geometry, fracture distribution, permeability, and porosity, are the same as in Case #1, except for BHP. The production history is shown in Fig. 3. The b_i is calculated as 0.5745 for this case, which is used to conduct straight-line analysis in Fig. 4, with an estimation of OGIP as 14.65 BSCF. This predicted value matches well with the known value of 15.28 BSCF, with an error of 4.12%. Fig. 5 shows that the unit slope trend cannot be sustained when plotting the q_{Gsc} versus $m(p_{wf})$ in the log-log coordinate, which implies that the γ constant assumption is not followed for this case. However, a reasonable OGIP value can still be obtained, which further validates the effectiveness of this methodology.

3.3 Case #3

The schematic of the gas reservoir for this case is shown in Fig. 6, where the irregular outer boundary is applied. The gas well is designed to deplete under constant BHP condition of 3,000 psia from an initial pressure of 5,000 psia. The input parameters are the same as in Case #1 except the reservoir outer radius. A clear straight line is obtained in Fig. 7. OGIP is explicitly determined to be 18.9 BSCF, which has an error

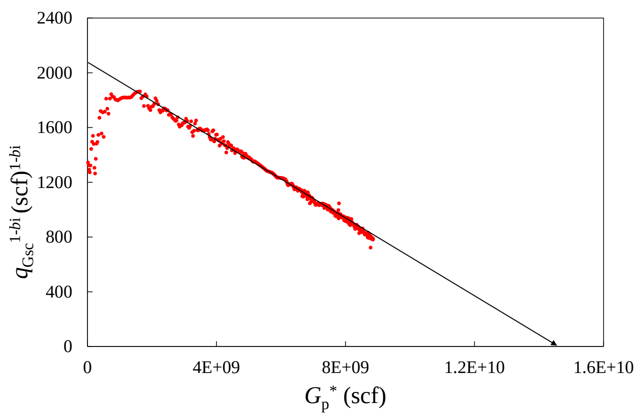

Fig. 4. Straight-line analysis for Case #2.

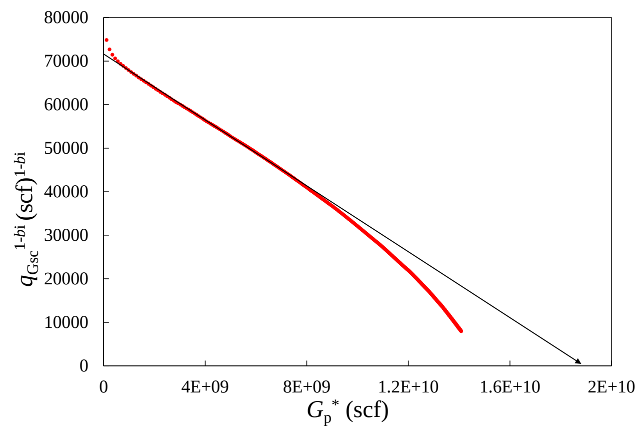

Fig. 7. Straight-line analysis for Case #3.

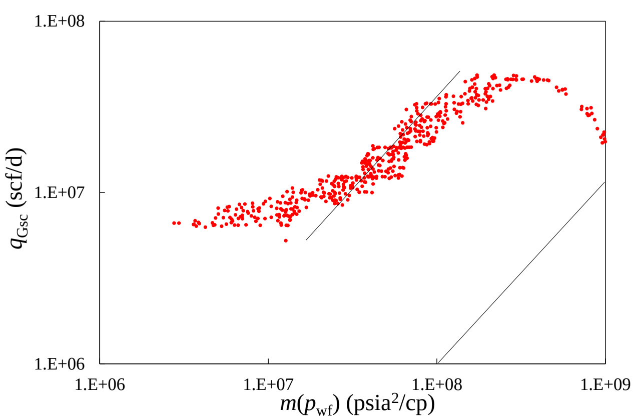

Fig. 5. Relationship of q_{Gsc} versus $m(p_{wf})$ in log-log plot for Case #2.

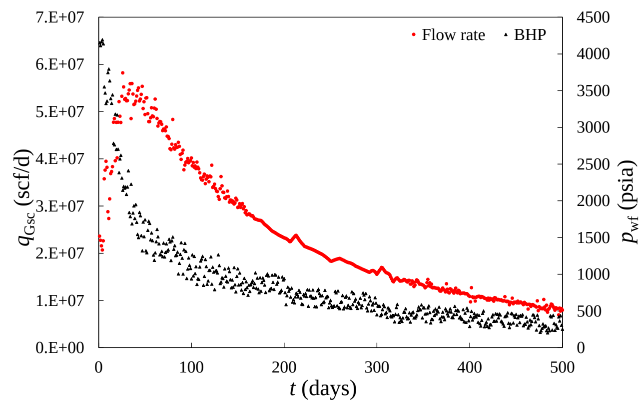

Fig. 8. Production history for Case #4.

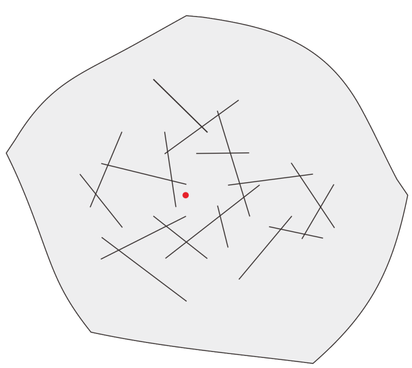

Fig. 6. Schematic of the gas reservoir for Cases #3 and #4.

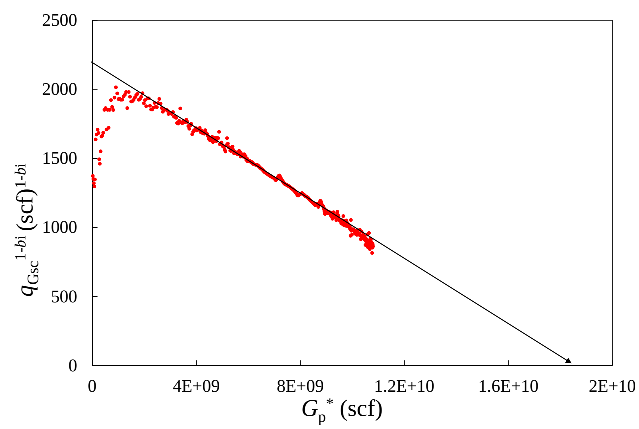

Fig. 9. Straight-line analysis for Case #4.

of 0.32% compared with the known value of 18.96 BSCF.

3.4 Case #4

Case #4 extends Case #3 from the constant BHP to the variable BHP condition. The simulated production history of this case is provided in Fig. 8. The straight-line analysis is presented in Fig. 9, which extrapolates to an OGIP of 18.8 BSCF. This predicted value compares well with the known value of 18.96 BSCF with an error of 0.84%. Once more, an approximate unit slope may not be obtained for this case when plotting q_{Gsc} versus $m(p_{wf})$ in the log-log coordinate (Fig. 10), which means that the constant γ assumption does not hold. However, this methodology can still provide good insights into explicit OGIP estimation.

4. Concluding remarks

This study extends the applicability of the explicit OGIP determination method from homogeneous reservoirs to naturally fractured reservoirs under constant or variable BHP con-

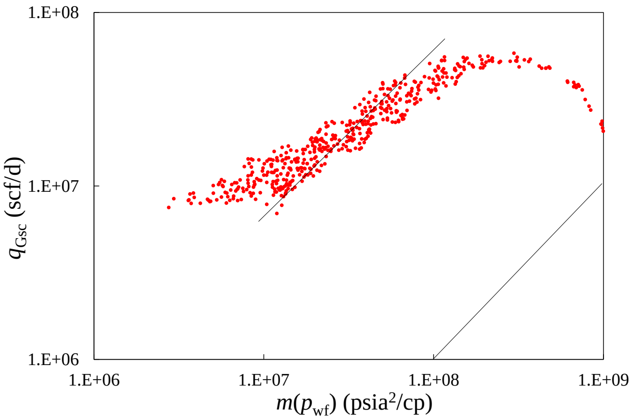

Fig. 10. Relationship of q_{Gsc} versus $m(p_{wf})$ in log-log plot for Case #4.

ditions in gas-well rate decline analysis. The gas flow rate versus average pseudo-pressure for a naturally fractured reservoir is captured through the introduction of a new productivity index parameter, which takes into consideration the interporosity flow between fracture and matrix in a natural fractured gas-reservoir producing under constant or variable BHP conditions. Rather than implementing pseudo-time or material-balance pseudo-time transformations, the presented step-by-step procedures provide explicit and straightforward OGIP estimation. Simulated cases are presented to demonstrate that the explicit OGIP determination method can be successfully applied in heterogeneous naturally fractured reservoirs with irregular outer boundaries.

The limitations of the proposed methodology prompt future work including the incorporation of different flow mechanisms, like adsorption and desorption, slippage effect, non-Darcy flow, and so on. In addition, this current development is constrained to volumetric, single-phase (naturally fractured) gas reservoirs; more research is required to account for multiphase flow in naturally fractured gas reservoirs.

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Conflict of interest

The authors declare no competing interest.

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