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Original article

Characterizing hydraulic fractures in shale gas reservoirs using transient pressure tests

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A R T I C L E I N F O

Article history: Received 21 April 2015 Accepted 29 May 2015

Keywords: Hydraulic fractures Shale gas reservoirs Transient pressure tests Reservoir simulation Formation characterization Gas adsorption

ABSTRACT

Hydraulic fracturing combined with horizontal drilling has been the technology that makes it possible to economically produce natural gas from unconventional shale gas or tight gas reservoirs. Hydraulic fracturing operations, in particular, multistage fracturing treatments along with horizontal wells in unconventional formations create complex fracture geometries or networks, which are difficult to characterize. The traditional analysis using a single vertical or horizontal fracture concept may be no longer applicable. Knowledge of these created fracture properties, such as their spatial distribution, extension and fracture areas, is essential information to evaluate stimulation results. However, there are currently few effective approaches available for quantifying hydraulic fractures in unconventional reservoirs.

This work presents an unconventional gas reservoir simulator and its application to quantify hydraulic fractures in shale gas reservoirs using transient pressure data. The numerical model incorporates most known physical processes for gas production from unconventional reservoirs, including two-phase flow of liquid and gas, Klinkenberg effect, non-Darcy flow, and nonlinear adsorption. In addition, the model is able to handle various types and scales of fractures or heterogeneity using continuum, discrete or hybrid modeling approaches under different well production conditions of varying rate or pressure. Our modeling studies indicate that the most sensitive parameter of hydraulic fractures to early transient gas flow through extremely low permeability rock is actually the fracture-matrix contacting area, generated by fracturing stimulation. Based on this observation, it is possible to use transient pressure testing data to estimate the area of fractures generated from fracturing operations. We will conduct a series of modeling studies and present a methodology using typical transient pressure responses, simulated by the numerical model, to estimate fracture areas created or to quantity hydraulic fractures with traditional well testing technology. The type curves of pressure transients from this study can be used to quantify hydraulic fractures in field application.

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1. Introduction

For the unconventional gas reservoirs, hydraulic fractures characterization is important in assuring the maximum stimulation efficiency [1-3]. A lot of researches have been carried out on the flow behavior analysis of vertical wells with finite-conductivity or infinite-conductivity hydraulic fractures. Cinco-Ley and Samaniego summarized fluids flow in a hydraulic fractured well could be divided into four periods: fracture linear flow, bilinear flow, formation linear flow and pseudo-radial flow [4]. Nobakht and Clarkson pointed out that the dominant flow regime observed in most fractured tight/shale

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Peer review under responsibility of Southwest Petroleum University.



http://dx.doi.org/10.1016/j.petlm.2015.05.002

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gas wells is the third one, formation linear flow, which may continue for several years [5]. Transient pressure analysis of this linear flow behavior is able to provide plenty of useful information, especially, the total contact area between hydraulic fractures and tight matrix.

Pseudo-pressure, a mathematical pressure function that accounts for the variable compressibility and viscosity of gas with respect to pressure, is widely used for the transient pressure analysis in conventional gas reservoirs [6]. Compared with conventional reservoirs, gas flow in ultra-low permeability unconventional reservoirs is subject to more nonlinear, coupled processes, including nonlinear adsorption/desorption, non-Darcy flow (at both high flow rate and low flow rate), strong rock-fluid interaction, and rock deformation within nano-pores or micro-fractures, coexisting with complex flow geometry and multi-scaled heterogeneity. Therefore, quantifying flow in unconventional gas reservoirs has been a significant challenge and traditional REV-based Darcy law, for example, may not be generally applicable. For gas flow in these unconventional reservoirs, our previous work indicates that gas-slippage effect and adsorption/desorption play an important role to describe the subsurface flow mechanisms, which cannot be neglected [7]. To the authors' knowledge, these two factors were not considered in the previous pseudo-pressure derivation. In this paper, a new derivation of pseudo-pressure is provided.

This paper presents our continual efforts in developing numerical models and tools for quantitative studies of unconventional gas reservoirs [8,9]. Specifically, we explore the possibility of performing well testing analysis using the developed simulator. The numerical model is able to simulate realistic processes of single-phase or two phase flow in unconventional reservoirs, which considers the Klinkenberg effects and gas adsorption/desorption. We use the numerical model to verify our new derived pseudo-pressure formulation. We also apply it to generate type-curves of transient gas flow in unconventional reservoirs with horizontal well and multistage hydraulic fractures. The type curves of pressure transients from this study can be utilized to quantify hydraulic fractures in field application.

2. Derivation of new pseudo pressure

In 1965, Al-Hussainy and Ramer derived the pseudo pressure which has been successfully used to analyze the flow of real gas in the gas reservoirs.

$$m(P) = 2 \int_{P_0}^{P} \frac{P'}{\mu Z} dP'$$
 (1)

where P_0 is the reference pressure; P is gas pressure; μ is the gas viscosity and Z is gas pressure Z factor.

The concept of the real gas pseudo-pressure promises a considerable simplification. It brings improvement in all phases of gas well aWnalysis and gas reservoir calculations. These analysis and calculations in terms of pseudo-pressure work very well for the conventional reservoirs but meet some problems when it is directly applied in the unconventional reservoirs analysis. This is mainly because gas flow in ultralow permeability unconventional reservoirs, different from the gas flow in conventional reservoirs, is subject to more nonlinear, coupled processes, including nonlinear adsorption/ desorption, non-Darcy flow, and strong rock—fluid interaction,

and rock deformation within nanopores or micro-fractures, coexisting with complex flow geometry and multi-scaled heterogeneity.

Considering the Klinkenberg effects and gas adsorption, the principle of conversation of mass for isothermal gas flow through a porous media is expressed by the expression:

$$\nabla \cdot \left[\rho \frac{k(P)}{\mu(P)} \nabla P \right] = \frac{\partial}{\partial t} \left[\phi \rho + \frac{m_{g}(V)}{V} \right]$$
(2)

The pressure-dependent permeability for gas is expressed by Klinkenberg as:

$$k_{\rm g} = k_{\infty} \left(1 + \frac{b}{P_{\rm g}} \right) \tag{3}$$

where k_{∞} is constant, absolute gas-phase permeability in high pressure (where the Klinkenberg effect is minimized); and *b* is the Klinkenberg *b*-factor, accounting for gas-slippage effect.

The mass of adsorbed gas in formation volume, *V*, is described by Refs. [10,11,7]:

$$m_{\rm g}(V) = \rho_K \rho_{\rm g} f(P) V \tag{4}$$

where $m_{\rm g}(V)$ is absorbed gas mass in a volume V, ρ_K is rock bulk density; $\rho_{\rm g}$ is gas density at standard condition; f(P) is the adsorption isotherm function. If the adsorbed gas terms can be represented by the Langmuir isotherm (Langmuir, 1916), the dependency of adsorbed gas volume on pressure at constant temperature is given below,

$$f(P) = V_{\rm L} \frac{P}{P + P_{\rm L}} \tag{5}$$

where V_L is the gas content or Langmuir's volume in scf/ton (or standard volume adsorbed per unit rock mass); *P* is reservoir gas pressure; and P_L is Langmuir's pressure, the pressure at which 50% of the gas is desorbed.

For real gas,

$$\rho = \frac{M}{RT} \left[\frac{P}{Z(P)} \right] \tag{6}$$

Substitute Equations (3)–(6) into Equation (2),

$$\nabla \cdot \left[\frac{P\left(1 + \frac{b}{P}\right)}{\mu(P)Z(P)} \nabla P \right] = \frac{\phi}{k_{\infty}} \frac{\partial}{\partial t} \left[\frac{P}{z(P)} + \frac{RT\rho_{K}\rho_{g}V_{L}P}{\phi M(P + P_{L})} \right]$$
(7)

From the definition of the isothermal compressibility of gas:

$$c_{g}(P) = \frac{Z(P)}{P} \frac{d}{dP} \left[\frac{P}{Z(P)} \right]$$
(8)

We also define the "compressibility" from the adsorption:

$$c_{a}(P) = \frac{Z(P)}{P} \frac{d}{dP} \left[\frac{RT\rho_{K}\rho_{g}V_{L}P}{\phi M(P+P_{L})} \right] = \frac{Z(P)}{P} \frac{RT\rho_{K}\rho_{g}V_{L}P_{L}}{\phi M(P+P_{L})^{2}}$$
(9)

Let the total compressibility:

$$c_{t}(P) = c_{a}(P) + c_{g}(P) \tag{10}$$

Equation (7) will be:

$$\nabla^2 P^2 - \frac{d\left[\ln\frac{\mu(P)Z(P)}{1+b/P}\right]}{dP^2} \left(\nabla P^2\right)^2 = \frac{\phi\mu(P)c_t(P)}{k(1+b/P)}\frac{\partial P^2}{\partial t}$$
(11)

Assume the viscosity and gas law deviation factors change slowly with pressure changes; the second part of Equation (11) becomes negligible. Equation (11) becomes:

$$\nabla^2 P^2 = \frac{\phi\mu(P)c_t(P)}{k(1+b/P)} \frac{\partial P^2}{\partial t}$$
(12)

We define the new pseudo-pressure m(P) as follows:

$$m(P) = 2 \int_{P_0}^{P} \frac{P'(1+b/P)}{\mu(P)Z(P)} dP'$$
(13)

Equation (2) can be rewritten in terms of variable m(P) using the definition of $c_t(P)$ given by Equations (8)–(10) as

$$\nabla^2 m(P) = \frac{\phi \mu(P) c_t(P)}{k(P)} \frac{\partial m(P)}{\partial t}$$
(14)

Based on Equation (14), we could apply this form of the flow equation, quasi-linear flow equation, to the analysis of real gas flow behavior in unconventional reservoirs.

3. Linear gas flow

The early flow regime observed in fractured tight/shale gas wells is linear flow from formation, which may continue for several years. Sometimes decline curve may indicate outer boundary effects, but no pseudo-radial flow. Wattenbarger et al. gave the "short-term" approximations for this linear flow with constant rate production conditions [12];

$$m_{\rm Di} - m_{\rm Dwf} = q B \sqrt{\frac{\pi \mu}{\phi c_{\rm t}}} \frac{1}{\sqrt{k}A} \sqrt{t}$$
(15)

In Equation (15), m_D is the pseudo pressure; q is the gas production rate; B is the gas FVF; ϕ is the formation porosity; c_t is the total compressibility, k is the formation permeability; A is the hydraulic fracture area; t is the time; and subscript i refers to initial condition and subscript wf refers to the wellbore condition.

Equation (15) indicates that for the constant-flowing-rate production condition, linear flow appears as a straight line on the plot of normalized pressure vs. the square root of time. The slope of this square-root-of-time plot can be used to estimate the total contact area between hydraulic fracture and the tight matrix. The estimation accuracy is influenced by initial pressure, formation average permeability and total compressibility [5].

This model is limited by the assumptions of only one infiniteconductivity hydraulic fracture and the neglect of gas adsorption/desorption effect. For the gas flow analysis in unconventional reservoirs, these assumptions are generally unacceptable. Multi-stage hydraulic fracturing is the key technology in developing the unconventional shale gas or tight gas reservoirs. In addition, our previous work indicates that adsorbed gas could contribute more than 30% to the total production in some unconventional shale gas reservoirs [7]. For the above situations, estimations considering the effects of gas adsorption/desorption will be more accurate and it will avoid the overestimation of total hydraulic fracture area.

One efficient approach to include the adsorption is by adding an "adsorption compressibility" term into the total compressibility. Based on the derived "adsorption compressibility" formulation in Equation (9), the value of adsorption compressibility is calculated below. Table 1 lists the data used in this calculation and Fig. 1 shows the gas corresponding *Z* factor value with pressure.

Fig. 2 is the calculated adsorption compressibility value and this value is in the same magnitude with the rock and fluids total compressibility. These calculation results indicate that when the pressure increases from 2000 psi to 5000 psi, this compressibility drops significantly from 2.71 \times 10⁻⁴/psi to 4.29 \times 10⁻⁵/psi.

4. Numerical model

The unconventional oil/gas reservoir simulator developed coupled multiphase fluid flow with the effects of rock deformation, gas slippage, non-Darcy flow and chemical reaction of adsorption and desorption processes in unconventional reservoirs. In numerical formulation, the integral finite difference method [13] is used for space discretization of multidimensional fluid and heat flow in porous and fractured reservoirs using an unstructured/structured grid. Time is discretized fully implicitly as a first-order backward finite difference. Time and space discretization of mass balance equations results in a set of coupled non-linear equations, solved fully implicitly using Newton iteration [7].

In our model, a hybrid-fracture modeling approach, defined as a combination of explicit-fracture (discrete fracture model), MINC (Multiple Interacting Continua) approach [13] on the stimulated zones, and single-porosity modeling approaches on unstimulated areas (Figs. 3 and 4), is used for modeling a shale gas reservoir with both hydraulic fractures and natural fractures [14–16]. This is because hydraulic fractures, which have to be dealt with for shale gas production, are better handled by the explicit fracture method. On the other hand, natural fractured reservoirs are better modeled by a dual-continuum approach, such as MINC for extremely low-permeability matrix in shale gas formations, which cannot be modeled by an explicit fracture model.

Fig. 4 illustrates the conceptual model including a horizontal well, multistage hydraulic fractures and their corresponding stimulated reservoir volume (SRV). The stimulated reservoir volume (SRV) is defined as the 3D volume of microseismic-event cloud nearby the hydraulic fractures, inside which complex natural fracture networks are stimulated. We apply the method of MINC to model this the porous and fractured medium. A single-porosity model is applied in the region outside the SRV. In this method, hydraulic fractures are represented by grids matching the real fracture geometric data. Then the properties of the fractures, such as permeability and permeability, are assigned to the corresponding fracture grids.

Table 1	
Data used in the calculation of two compressibility.	

Parameters	Value	Units
Gas type	Methane	
Porosity, ϕ Temperature T	0.05	F
Rock density, ρ_K	2.7	g/cc
Langmuir's volume, V _L	218.57	Scf/ton
Langmuir's pressure, P _L	2285.7	psi



Fig. 1. Methane *Z* factor at 122 F from 2000 to 5000° psi.



Fig. 2. "Adsorption compressibility" vs. pressure.

5. Model applications

In this section, we apply the numerical model to analyze transient pressure behaviors vs. fracture areas. Here we present a set of simulation cases to study the gas flow characteristics in fractured wells.

In the first simulation case, the formation is homogeneous with no natural fractures. A refining grid system is built for the simulation. The simulation input parameters are summarized in Table 2. The fluids include gas and water, but water is at residual or immobile, so it is a single-phase gas flow problem. The

hydraulic fractures are represented by a discrete fracture with infinite conductivity. With the input parameters as shown in Table 2, the dimensionless fracture conductivity is calculated by its definition, $C_{\rm fd} = k_{\rm f} w_{\rm f} / k_{\rm m} w_{\rm m}$. Its value is large enough thus the hydraulic fracture could be treated as infinite conductivity.

Three different fracture models with the same total fracturematrix contact area are built, as demonstrated in Figs. 5–7. Fig. 8 illustrates the simulated wellbore bore pseudo-pressure vs. time for these three cases. Their pressure change with time are almost same, which indicates that fracture number and fracture geometry, as long as the total fracture area keep the same, have little influence on the wellbore pressure change for gas production from extremely low permeability rock.

Next we compare the transient pressure behavior in early time with different fracture-matrix total contact area. Two cases with different area are run and Fig. 9 is the simulation result. A larger surface area will lead to a slower increase of the dimensionless pseudo-pressure. Slope of this line is inversely proportional to the fracture area.

Gas adsorption influence is also analyzed. Two cases with different initial pressures are run, one is 2350 psi and the other is 3800 psi, respectively. The results are illustrated in Figs. 10 and 11. Two conclusions could be drawn from these simulation works:

- Gas flow with adsorption will also behave straightly in the normalized pressure vs. the square root of time plot for the linear flow period. This is identical with our previous analysis that adsorption could be treated by a compressibility factor if the pressure changes a little.
- 2. Adsorption will have different influences on the linear flow behavior at different initial pressure, as shown in Fig. 2 that "adsorption compressibility" drops with pressure increases.

6. Conclusions

In this paper, we derive a new formulation of gas pseudopressure for the transient pressure analysis in unconventional gas reservoirs. We prove its efficiency and accuracy by running a set of relevant simulation examples. We use the developed numerical model to simulate shale gas production with a continuum, discrete or hybrid modeling approach. Our modeling studies indicate that the most sensitive parameter of hydraulic fractures to early transient gas flow responses through extremely low permeability rock is actually the fracture-matrix contacting area, generated by fracturing stimulation. We observed that gas flow with adsorption will also behave straightly in the normalized pressure vs. the square root of time plot for the linear flow period, if an adsorption term is included in the total gas



Fig. 3. Discrete fracture methods and refining grids technology in our numerical model.



Fig. 4. The hybrid fracture model.

Table 2	
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Data used for the case study and discussion.

Reservoir length, Δx , ft	5500	Natural fracture total compressibility, c _{nf} , psi ⁻¹	2.5E-04
Reservoir width, Δy , ft	2000	Hydraulic fracture total compressibility, $c_{\rm hf}$, psi ⁻¹	2.5E-04
Formation thickness, Δz , ft	250	Initial reservoir pressure, P _i , psi	3800
Horizontal well length, L _h , ft	4800	Constant flowing bottomhole pressure, P _{wf} , psi	500
Production rate, Q, Mscf/day	5.0E+03	Reservoir temperature, T, °F,	122
Hydraulic fracture width, $w_{\rm f}$, ft	0.02	Klinkenberg coefficient, psi	200
Hydraulic fracture half-length, X _f , ft	250	Non-Darcy flow constant, $c_\beta m^{3/2}$	3.2E-06
Viscosity, μ , cp	0.0184	Langmuir's pressure, P _L , psi	2285.7
Matrix permeability, $k_{\rm m}$, md	1.0E-04	Langmuir's volume, $V_{\rm L}$, scf/ton	218.57
Matrix porosity, $\Phi_{ m m}$	0.05	Natural fracture total compressibility, $c_{ m nf}$, psi $^{-1}$	2.5E-04
Matrix total compressibility, $c_{ m tm}$, psi $^{-1}$	2.5E-04	Hydraulic fracture permeability, $k_{\rm hf}$, md	1E05
Natural fracture porosity, Φ_{nf} , md	0.3	Hydraulic fracture porosity, $\Phi_{ m hf}$	0.5
Natural fracture permeability, k_{nf} , md	100		



Fig. 5. Case 1, horizontal well with one fracture.



Fig. 6. Case 2, horizontal well with two fractures, symmetrical with the well.



Fig. 7. Case 3, horizontal well with two fractures, asymmetrical with the well.



Fig. 8. Pseudo pressure vs. time square for those 3 cases.



 $\ensuremath{\textit{Fig. 9}}$. Pseudo pressure vs. square root of time for those 2 cases with different fractures.



Fig. 10. Pseudo pressure vs. time square analysis about adsorption with initial pressure $2350^\circ \text{psi}.$



Initial Pressure is 3,800psi

Fig. 11. Pseudo pressure vs. time square analysis about adsorption with initial pressure 3800° psi.

compressibility. Based on this observation, we demonstrate that it is possible to use transient pressure testing data to estimate the area of fractures generated from fracturing operations. A methodology using typical transient pressure responses, simulated by the numerical model, to estimate fracture areas created or to quantity hydraulic fractures with traditional well testing technology is presented. The methodology as well as type curves of pressure transients from this study can be used for quantify hydraulic fractures in field application.

Acknowledgments

This work was supported in part by EMG Research Center and UNGI of Petroleum Engineering Department at Colorado School of Mines, and by Foundation CMG.

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