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Production data analysis of coalbed methane wells to estimate the time required to reach to peak of gas production

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ABSTRACT

For coalbed methane (CBM) wells with rising gas production, the time required to reach to peak of gas production and the peak gas rate are two fundamental features of production profile. This paper investigates the time of occurrence of peak of production using production data analysis (PDA). The methodology is simple and requires gas rates and flowing bottom-hole pressures (BHP). The derivative of square of BHP over gas rate at standard condition with respect to time is calculated for observed production data. Then using the methodology in the current work, signatures for time of peak production are identified. The signatures of peak time are obtained for constant and variable bottom-hole pressure operational constrains. The contribution of this method is to use the production data to estimate the time of peak production. Field and simulation production data are analysed to illustrate both signatures and estimations of time of peak production. The accuracy of estimation depends on the quality of production data and the goodness of the fitted functions used in this approach. This method provided satisfactory estimations for time of peak production for field and simulated cases presented in this paper. The current analysis may contribute to production forecasting for the negative decline portion of production profile.

1. Introduction

The term negative decline is referred to the increasing gas production rate of CBM wells. As a good rule of thumb, almost one third of the wells in any CBM field show the negative decline behaviour. The rest of the wells either exhibit declines in production profiles similar to conventional gas wells or have a complicated well history making reservoir response interpretation difficult (Seidle, 2011). The rising gas production from coal wells can last from a few months up to years and as a result of that the peak gas rate can be observed a few months or a few years after the start of production. The key characteristics of production profile of CBM wells that exhibit negative decline are time to reach to peak of production and peak gas rate. They are strongly controlled by sorption time and relative permeabilities to gas and water.

Sorption time allows investigating the combined impacts of gas diffusion in coal matrix and cleat spacing on gas flow (Karacan, 2008). Peak of gas production and the time of peak gas rate may be sensitive to coal sorption time. This depends on the interrelationship between diffusion mechanism in coal matrix and fluid flow mechanism in cleat system. Seidle (2011) discussed that for instantaneous gas desorption from coal matrix or sorption times of 1 to 10 days, well production profile is controlled by Darcy flow in cleat network and sorption time has a minor impact on the shape of production profile. Salmachi et al. (2014) conducted a series of simulation studies for optimum well placement in CBM reservoirs and reported the negligible impact of sorption time on gas production except at very early times. For coalbeds characterized by extremely slow desorption such as some seams in Warrior Basin of Alabama (McLennan, 1995), the well production profile is strongly controlled by sorption time.

Gas and water relative permeability curves are also important players controlling the time of peak production and peak gas rate. A few experimental studies on determination of relative permeability curves for some commercial coal seams are available in literature (Conway et al., 1995; Gash, 1991). Gash (1991) measured gas and water relative permeabilities for well-cleated coal samples in San Juan basin. Recently, other methods such as production history matching and reservoir simulation have been used to derive relative permeability curves. Karacan (2013) derived existing relative permeabilities to gas and water for Pratt, Mary Lee, and Black Creek coal using production history matching of 92 vertical wells in Black worrier basin. Clarkson et al. (2011) proposed a systematic approach to obtain the relative permeability of CBM reservoirs from field data. This approach includes estimation of flowing and shut-in pressures for producing wells and use of material balance and radial flow equations for estimation of effective permeability to each phase as a function of reservoir pressure.

Production data are a valuable source of information to extract substantial reservoir properties such as permeability-thickness product and skin factor. Production history matching, production data analysis,

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and rate transient analysis (RTA) employ production data for reservoir characteristics evaluation. The PDA techniques, including type-curve analysis, empirical methods, and analytical and numerical techniques when adapted for CBM reservoir complexities, can be used to obtain CBM reservoir characteristic (Aminian et al., 2004; Mohaghegh and Ertekin, 1991). The decline curve analysis (Arps, 1945; Fetkovich, 1980) can be used to study the gas production decline in CBM wells. The decline in gas production in CBM wells, which is almost always an exponential decline (Seidle, 2002), occurs sometime after the peak of gas production has been observed. Clarkson conducted a comprehensive review on latest PDA techniques and their adaptation for CBM and shale gas resources (Clarkson, 2013; Clarkson et al., 2007). The rate transient analysis is a form of PDA that employs concepts and theories similar to the PDA (Clarkson, 2013) and requires production data and flowing bottom-hole pressures. RTA is analogues to a very long drawdown test. First, sequences of flow regimes such as transient and boundary dominated flows are identified using the pressure derivative or rate-normalized pressure derivative versus time plotted on logarithmic scales. Then reservoir properties such as permeability, fracture half length, and skin factor are extracted from special equations formulated for gas reservoirs. For unconventional resources (CBM and shale gas), corrections are required for the purpose of RTA analysis due to gas desorption, stress and desorption-dependent permeability, multi-phase flow, and non Darcy effects (Clarkson et al., 2012a, 2012b).

Due to combined effects of dewatering and depressurization, it is difficult to obtain the duration of negative decline (the time of peak of gas production) and the peak gas rate (Seidle, 2011). The aim of this study is to use the production data, including producing gas rates and flowing bottom-hole pressures, to investigate the time of occurrence of peak of gas production. A simple and practical approach is discussed in the methodology section to treat the production data and identify signatures of time of peak gas rate. The signatures of time of peak gas rate are obtained for both constant and variable bottom-hole pressure well constrains. Finally, it is tried to estimate the time of peak of production by this approach. Simulation and field cases are presented for demonstration of this method.

2. Methodology

The approach in the current work is inspired from pressure derivative technique, which is used to identify the flow regimes in RTA and pressure transient analysis. In this section, we discuss the signature of time of peak gas rate by plotting the derivative of square of bottom-hole flowing pressure over gas flow rate at standard condition with respect to time versus production time in Cartesian coordinate. The resulting signatures for two operational constrains (constant bottom-hole pressure and variable bottom-hole pressure) are discussed. Simulation and field cases are demonstrated to show the signature of time of peak gas rate. Regardless of the operational well constrain, $\frac{\partial}{\partial t}\left(\frac{P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}}\right)$ can be written and expanded by Eq. (1):

$$\frac{\partial}{\partial t}\left(\frac{P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}}\right)=\frac{2\times P_{\mathrm{wf}}\times\frac{\partial P_{\mathrm{wf}}}{\partial t}\times q_{\mathrm{sc}}-\frac{\partial q_{\mathrm{sc}}}{\partial t}\times P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}^{2}} \tag{1}$$

Here P_{wf} is the flowing bottom-hole pressure, q_{sc} is the gas flow rate at standard condition, and t is time.

2.1. Constant bottom-hole pressure

Coal seam gas wells are normally operated with a stable fluid level and constant well head pressure making them perfect cases for constant bottom-hole pressure constrain (Seidle, 2011). When operational well constrain is *constant bottom-hole pressure* $\left(\frac{\partial P_{\mathrm{wf}}}{\partial t}=0\right)$, Eq. (1) is reduced to Eq. (2):

$$\frac{\partial}{\partial t}\left(\frac{P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}}\right)=-\frac{\frac{\partial q_{\mathrm{sc}}}{\partial t}\times P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}^{2}} \tag{2}$$

Eq. (2) indicates that the derivative of square of BHP over gas flow rate at standard condition with respect to time is negative when gas rate rises during the negative decline period. At the peak of gas production (the maximum point of gas rate versus time curve), the derivative of gas flow rate with respect to time is equal to zero $\left(\frac{\partial q_{\mathrm{sc}}}{\partial t}=0\right)$. This makes the derivative of square of BHP over gas flow rate at standard condition with respect to time equals to zero $\left(\frac{\partial}{\partial t}\left(\frac{P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}}\right)=0\right)$. Theoretically, when $\frac{\partial}{\partial t}\left(\frac{P_{\mathrm{wf}}^{2}}{q_{\mathrm{sc}}}\right)$ is plotted versus production time in Cartesian coordinate, the time of peak gas rate occurs when the curve intersects with the time axis. Hence, the time of peak gas rate is the root of Eq. (2). This can be used as the signature for time of peak gas rate when coal well is producing at constant bottom-hole pressure.

2.2. Simulation example (constant BHP)

Reservoir simulation is employed to generate production data for a coal well and demonstrate the signature of time of peak production. The simulation is performed using the coalbed methane module of Computer Modelling Group (CMG). In this example, production data are generated for a vertical CBM well in a bounded reservoir. The production data are then analysed to show the signature of time of peak gas rate. Table 1 summarizes the input parameters and their values used to construct the simulation model. The relative permeability curves used for the purpose of simulation are also shown in Fig. 1.

Gas and water production are generated for a vertical perforated well in a bounded reservoir producing at constant bottom-hole pressure. Coal permeability and sorption time are 10 mD and 200 days, respectively. The operational well constrain is set at constant bottom-hole pressure of 500 kPa (72.5 psia). Fig. 2 shows the gas production profile of the well for 20 years from the start of production. The peak of gas production is experienced almost after 4 and half years from the start of production indicating a slow negative decline. The peak gas rate is 1870 m^3/day. After the peak gas rate is observed, gas rate exponentially declines. The resulting straight line on semi-log plot of gas rate versus time in Fig. 3 indicates the exponential decline behaviour. The exponential decline can be formulated using Eq. (3):

$$q=q_i e^{\left(\frac{-D(t-t_0)}{365}\right)} \tag{3}$$

Table 1
Reservoir parameters used for simulation.

Input parameter	Parameter value
Reservoir thickness (ft)	65.6
Initial absolute horizontal permeability (mD)	10
Initial absolute vertical permeability (mD)	1
Initial water saturation	1
Initial reservoir pressure (kPa)	6000
Gas content (SCF/ton)	261.37
Reservoir temperature (°C)	35
Fracture porosity (%)	2
Coal desorption time (days)	200
Langmuir volume (SCF/ton)	480.5
Langmuir pressure (kPa)	5030
Drainage area (acres)	41
Skin factor	−2