# DETERMINING GAS RATE DISTRIBUTION FROM TEMPERATURE AND PRESSURE PROFILES IN GAS WELL

by

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*A simple and effective method of the gas rate prediction from temperature and pressure data is discussed in this paper. Solving the inverse problem allows determination of the flow rate by matching the gas pressure and temperature distributions with measured profiles. Results of field data treatment show good agreement with the model prediction.*

Key words: *gas well, flow rate, pressure profile, temperature profile*

## Introduction

Pressure, temperature, and flow rate are the most important information expected from the production logging. For the flow rate, direct flowmetering is still difficult and costly, especially for multiphase-flowing wells and complex well trajectories [1]. Regarding the pressure and temperature profiles, continuous measurement in a complex well can be obtained accurately and inexpensively.

A number of researchers have reported their work on the rate estimation from measured temperature and pressure profiles [2-4]. However, the models aiming at flow profiling involving multiphase-flow or coupled reservoir-well flow are either complicated for engineering applications or dependent on additional information, *e. g*. reservoir properties [5].

This paper proposes an effective inverse problem solver derived from the first principles, to predict rate profile using the gas temperature and pressure data. This technique offers tremendous advantage where high temperature production logging is either unavailable or prohibitively expensive.

## Mathematical model for non-isothermal gas flow in vertical well

The goal of the study is to determine well rate from pressure and temperature profiles, $p(z)$ and $T(z)$. Figure 1 shows $p$ and $T$ profiles (black dotted curves) as measured in gas well during production (field A, Australia). The geothermal line, fig. 1(b), corresponds to the

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earth temperature $T_e(z)$ calculated from field data of geothermal gradient and temperature at given depth. The reservoir consists of 9 production layers. The depths of inflow points are known. The problem is to determine rates from all layers using $p(z)$ and $T(z)$ in the well, by minimizing the deviation between measured and predicted $p(z)$ and $T(z)$ profiles.

Consider the vertical gas flow between two inflow points. The mass flux between two inflow points is constant: $\rho vA$ = const. The momentum balance shows that the vertical pressure gradient of gas is equilibrated by the friction between the well wall and flowing gas, the gravity, and the inertia:

$$\frac{\mathrm{d}p}{\mathrm{d}z} = -\frac{f_F w^2}{\pi^2 r_{ti}^5}\frac{1}{\rho} - \rho g - \rho v \frac{\mathrm{d}v}{\mathrm{d}z}, \tag{1}$$

where $f_F$ is the Fanning friction factor, and the mass flow rate $w = \rho vA$. The equation of state for real gas is [6]:

$$\rho = \frac{pM_a\gamma_g}{ZRT}. \tag{2}$$

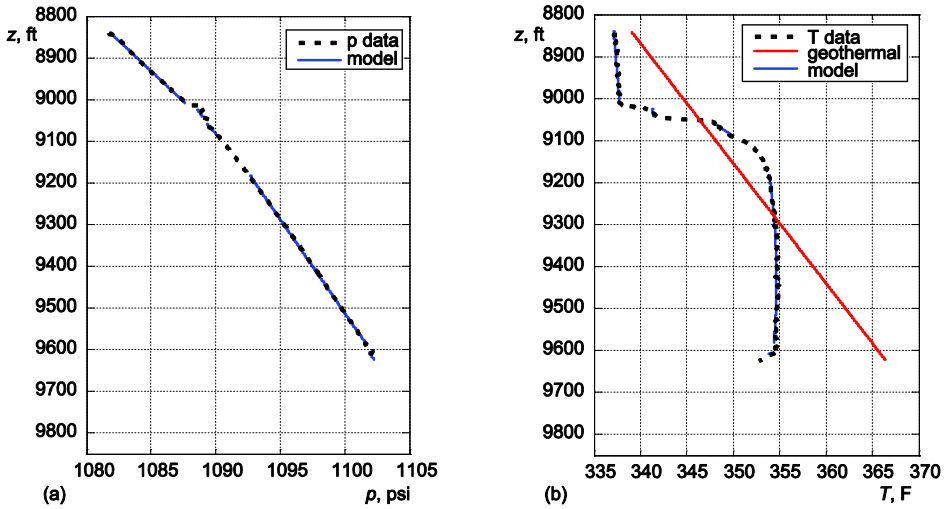


**Figure 1. Measured and model predicted pressure and temperature profiles along the well A; (a) pressure profile, (b) temperature profile**
(for color image see journal web site)

The energy balance includes the advective heat flux, vertical heat conduction, heat exchange with surrounded formation, Joule-Thomson expansion, work against gravity, and kinetic energy:

$$\frac{\mathrm{d}T}{\mathrm{d}z} = \frac{1}{\rho c_p v}\frac{\mathrm{d}}{\mathrm{d}z}\left(\lambda_g \frac{\mathrm{d}T}{\mathrm{d}z}\right) + \frac{Q}{c_p w} + C_J \frac{\mathrm{d}p}{\mathrm{d}z} - \frac{1}{c_p} g - \frac{v}{c_p}\frac{\mathrm{d}v}{\mathrm{d}z}. \tag{3}$$

where $c_p$ is the gas heat capacity, $Z$ – the gas deviation factor, and $C_J$ – Joule-Thomson coefficient. The heat conduction along the well and kinetic energy can be neglected [7]. The heat flux from the reservoir formation into the well is given by $Q = -2\pi r_{to} U_T (T - T_e)$, where $U_T$ is

the overall heat transfer coefficient. Usually it is assumed that the earth temperature in the reservoir $T_e$ depends on the depth $z$ linearly and, therefore, can be calculated from the geothermal gradient $g_G$: $T_e = T_e b - g_G z$. Define $L_R$ as the heat exchange coefficient between the well and the reservoir. The final equation for temperature is as follows:

$$\frac{\mathrm{d}T}{\mathrm{d}z} = -L_R\left(T - T_{eb} + g_G z\right) - C_J\left(\frac{f_F w^2}{\pi^2 r_{ti}^5}\frac{1}{\rho} + \rho g\right) - \frac{1}{c_p} g. \tag{4}$$

The Cauchy data for the system (1) and (4) are given pressure and temperature at the bottom of the discussed interval between two inflow points: $p(z_b) = p_b$, $T(z_b) = T_b$.

The numerical solution for the problem (1) and (4) along with solution of the inverse problem for the rate determination is presented in the next section.

## Iterative method for the inverse problem

An effective method of iteration is derived to solve the system of two ordinary differential equations (1) and (4) using the fourth order Runge-Kutta method. The minimization of the quadratic difference between the measured profiles $p_m(z)$ and $T_m(z)$ and the modeled profiles is performed using the Levenberg-Marquardt optimization algorithm. The well rate $w$ between two inflow points are determined by the minimization:

$$\min_{w,\lambda_e} \int_0^L \left\{ \left[\frac{p(z,w,\lambda) - p^m(z)}{p_b}\right]^2 + \left[\frac{T(z,w,\lambda) - T^m(z)}{T_b}\right]^2 \right\} \mathrm{d}z. \tag{5}$$

Equation (5) represents the tuning of the solution of system (1) and (4) by two measured profiles of pressure and temperature. The tuning parameters are well rate $w$, and horizontal thermal conductivity $\lambda_e$.

The proposed iterative algorithm takes advantage of the results from the approximate estimate formulae. The initial values of $w_0$ and $\lambda_{e0}$ are taken from the explicit formulae [8]. Further iterations to solve the minimization problem (5) are performed using the Levenberg-Marquardt optimization algorithm. Separate treatment of each well interval leads to the prediction of the rate profile along the wellbore.

## Treatment of field case A

Let us apply the algorithm to the solution of the inverse problem of determining the constant rate between two inflow points to a field case. The field A is located in Cooper Basin, Australia. The field data are presented in figs. 1(a) and 1(b) by dotted curves (black), while blue lines show the modeling-based predictions obtained after the matching. Red curve corresponds to the earth temperature. The reservoir consists of 10 layers that produce gas. So, 9 intervals between inflow points have been treated using the algorithm. Good match between the modeled and measured data takes place. It corresponds to both pressure and temperature profiles.

Figures 2(a) and 2(b) present the rates as obtained for each interval (lines with green triangles) and as obtained from logging (lines with blue square dots). The data almost coincide. Figure 2(a) presents the rate profile along the well column (accumulated rate) while fig. 2(b) shows the rate from each layer. The conclusion that just three upper layers and one lower layer contribute to the overall flux, can be used in decision making and planning of well stimulation.

An excellent match of flow rate as calculated from pressure and temperature profiles and from logging (fig. 2) further validates the proposed method.

## Discussion and conclusions

The main physical factors determining the pressure distribution along the vertical well are gas gravity and friction between the wellbore and flowing gas. The effects of the inertia, heat exchange with the reservoir, Joule-Thomson phenomenon, potential and kinetic energy on pressure profile are negligible if compared with the effects of gas gravity and friction. The temperature profile along vertical wells is determined mostly by the heat exchange with the surrounded formation, potential energy of gas, gas gravity, and Joule-Thomson effect; the effects of kinetic energy of gas, friction and gas inertia are negligible if compared with the influence of heat exchange term.

Pressure and temperature profiles along the well allow determining the rate profile by tuning systems of two ODE. The rates from individual productive layers, as determined by the modeling and that from logging data are in good agreement. The above validates the method of determining inflow rate for different layers from pressure and temperature profiles measured during production.

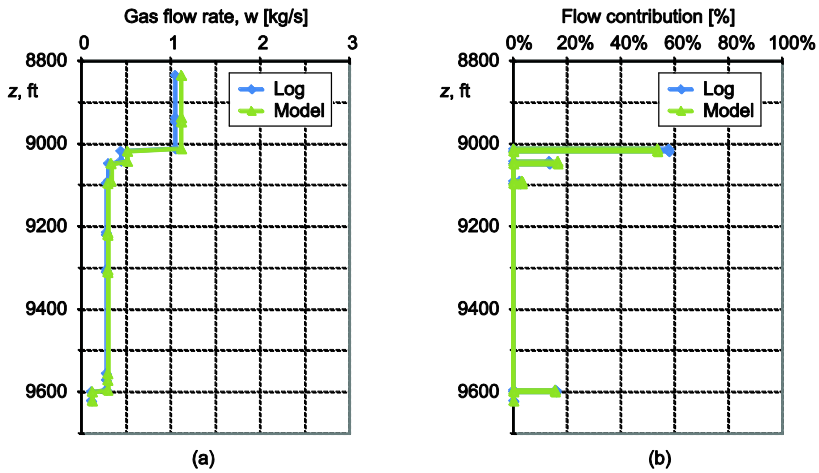


**Figure 2. Predicted gas flow rate along the well; (a) accumulated gas flow rate, (b) flow rate contribution by different layers**
(for color image see journal web site)

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