



DETERMINATION OF THE DEVELOPMENT INDICATORS OF A DEEP-LYING GAS-CONDENSATE RESERVOIR TAKING INTO ACCOUNT THE EFFECT OF WELLBORE VOLUME

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ABSTRACT

The efficiency of hydrocarbon field development is primarily determined by the completeness of the information obtained about the "well-reservoir" system and the effectiveness of the applied technical and technological approaches, as well as by the degree of completeness and accuracy of the computational methods used in the design and analysis of the development process, taking this process into account. This is particularly important for the efficient development of deep-lying reservoirs. In this regard, the paper considers, for the case of a bounded, isotropic, and heterogeneous reservoir model with fluid and reservoir properties dependent on pressure, as well as an unsteady-state axisymmetric radial inflow model of a gas-condensate mixture toward the well, the problem of determining the development indicators of a deep-lying gas-condensate reservoir, taking into account the effect of the wellbore volume. As a result, based on a binary gas-condensate flow model, a numerical scheme was developed for simulating gas-condensate well performance in a nonlinearly elastically deformable deep-lying gas-condensate reservoir, taking into account the effect of wellbore storage. The calculation results and their analysis, based on the developed numerical scheme, demonstrate the necessity of taking into account the effect of wellbore storage when calculating the operational indicators of a well. The use of the developed numerical scheme in practical applications makes it possible to improve the efficiency of developing deep-lying gas-condensate reservoirs by carrying out preliminary computational procedures to select the most appropriate production parameters for their operation.

Keywords: deep-lying gas-condensate reservoir; development indicators; well performance; wellbore storage coefficient; numerical scheme.

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1. Introduction

The efficiency of oil and gas field development is primarily determined by the completeness of the information obtained about the «well-reservoir» system and the effectiveness of the applied technical and technological approaches, as well as by the degree of completeness and accuracy of the computational methods used in the design and analysis of the development process, taking this process into account. This situation is particularly important for the efficient development of deep-lying fields. One of the main issues arising in this case is the comprehensive consideration of hydrocarbon flow processes toward the well under various influencing factors, as well as the issues associated with the possible consideration of the hydrodynamics of their behavior within the wellbore [1–4].

It is well known that the well flow rates measured at the wellhead and calculated at the bottomhole can differ significantly due to the influence of the physical and flow

properties of the fluids, as well as the well construction and operational characteristics, including the wellbore volume. This difference is manifested quantitatively, first of all, in the variation of bottomhole pressure over time. Under identical fluid-flow and operating conditions within the well, the coefficient C , which characterizes the wellbore storage effect, is considered one of the factors affecting the variation of bottomhole pressure, along with other technological indicators calculated as a function of this indicator. Various research approaches related to accounting for this factor have been presented in the literature. Among them, an important place is occupied by studies devoted to developing methods for reliable interpretation of well-testing data while taking into account the influence of this factor. However, when addressing issues related to the development of deep-lying hydrocarbon fields, from the perspective of developing methods for evaluating development performance indicators, this factor is considered theoretically and practically important, along with the multiphase nature of fluids, the influence of complex rock deformations, and flow non-equilibrium [5–15]. This is

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because, during the development of deep-lying hydrocarbon fields, fluid flow within the wellbore occurs under complex thermodynamic conditions, which requires the compressibility of the fluids to be taken into account during their flow inside the wellbore. In this case, the coefficient C , expressing the influence of the wellbore volume, primarily acts as a coefficient that approximately accounts for fluid compressibility during flow along the wellbore [12].

In this regard, the article addresses the problem of determining the development indicators of a gas-condensate reservoir, taking into account the effect of wellbore volume.

2. Problem statement and solution

It is assumed that the gas-condensate reservoir is developed by a single central well (with a volumetric condensate flow rate q). An unsteady axisymmetric radial inflow of the gas-condensate mixture toward the well is considered. The reservoir is assumed to be bounded, isotropic, and heterogeneous with respect to its properties, with fluid and reservoir characteristics (viscosity, compressibility, porosity, and permeability) dependent on pressure, while the inflow condition at the well is assumed to be isothermal. Under the aforementioned conditions, the development indicators of the gas-condensate reservoir are to be determined in the space-time domain $\{(r, t): r \in [r_w, r_k], 0 \leq t < \infty\}$ (where r_w is the well radius and r_k is the well drainage radius (reservoir)). To solve this problem, it is considered appropriate to use a binary flow model of the gas-condensate mixture in the reservoir. According to this model, at any given time, only two homogeneous phases—gas and liquid—are present and moving in the reservoir, with average physical properties; that is, the multicomponent nature of the phases is not explicitly considered. In this context, the flow of the gas-condensate mixture through the reservoir is considered as two-phase, two-component flow of a gas-condensate mixture [7]. It should be noted that in [19], this problem was solved without taking into account the effect of wellbore volume, at a specified volumetric gas flow rate.

The problem of determining the development indicators of a deep-lying gas-condensate reservoir, taking into account the influence of the wellbore volume and in accordance with the aforementioned initial assumptions, is formulated as follows [7, 16–19]:

- equations of unsteady inflow of the gas-condensate mixture to the well

$$\begin{aligned} \frac{1}{r} \frac{\partial}{\partial r} \left(\left(\frac{k(p)F_g(\rho_k)p\beta c(p)}{\mu_g(p)z(p)p_{atm}} + \frac{k(p)F_k(\rho_k)}{\mu_k(p)a_k(p)} \right) r \frac{\partial p}{\partial r} \right) &= \\ &= \frac{\partial}{\partial t} \left(m \left(\frac{(1-\rho_k)p\beta c(p)}{z(p)p_{atm}} + \frac{\rho_k}{a_k(p)} \right) \right) \\ \frac{1}{r} \frac{\partial}{\partial r} \left(\left(\frac{k(p)F_g(\rho_k)p\beta(1-c(p)\bar{\gamma}(p))}{\mu_g(p)z(p)p_{atm}} + \frac{k(p)F_k(\rho_k)S_k(p)}{\mu_k(p)a_k(p)} \right) r \frac{\partial p}{\partial r} \right) &= \\ &= \frac{\partial}{\partial t} \left(m \left(\frac{(1-\rho_k)p\beta(1-c(p)\bar{\gamma}(p))}{z(p)p_{atm}} + \frac{S_k(p)}{a_k(p)} \right) \right) \end{aligned} \quad (1)$$

- equations of state of the porous medium in accordance with the nonlinear elastic deformation of the reservoir [6,7]

$$m = m_0 e^{\beta(p-p_0)}, \quad k = k_0 e^{\alpha_k(p-p_0)}, \quad r_w < r < r_k, \quad t > 0 \quad (2)$$

- initial and boundary conditions

$$p(r, 0) = p_0, \quad \rho_k(r, 0) = 0, \quad r_w < r < r_k \quad (3)$$

$$\left\{ \left[2\pi r h \left(\frac{k(p)F_g(\rho_k)p\beta c(p)}{\mu_g(p)z(p)p_{atm}} + \frac{k(p)F_k(\rho_k)}{\mu_k(p)a_k(p)} \right) \right] \cdot \frac{\partial p}{\partial r} - C \frac{\partial p}{\partial t} \right\}_{r=r_w} = q(t) \quad (4)$$

$$\left. \frac{\partial p}{\partial r} \right|_{r=r_k} = 0, \quad t > 0 \quad (5)$$

Here, $p=p(r, t)$ denotes the current reservoir pressure; ρ_k , k and m denote the current condensate saturation, reservoir permeability, and porosity, respectively; p_0 , k_0 and m_0 denote the initial values of reservoir pressure, permeability, and porosity, respectively; $F_k(\rho_k)$ and $F_g(\rho_k)$ denote the relative phase permeabilities of the reservoir to condensate and gas, respectively; $\mu_k(p)$ and $\mu_g(p)$ denote the viscosities of condensate and gas, respectively; $a_k(p)$ denotes the condensate volume factor; $S_k(p)$ denotes the amount of gas dissolved in the liquid phase; $c(p)$ denotes the amount of condensate in the gas phase; $\bar{\gamma}(p)$ denotes the ratio of the densities of condensate in the liquid and gas phases under standard conditions; β_r denotes the rock compressibility coefficient of the reservoir; α_k denotes a constant coefficient expressing the rate of permeability reduction as a function of pressure change; h denotes the reservoir thickness; β is the temperature correction factor for gas; C is the wellbore volume effect coefficient; p_{atm} denotes atmospheric pressure.

For the numerical solution of the problem, by substituting $\xi = \ln \frac{r}{r_w}$, the initial domain of integration of the problem is transformed into the domain $\{0 \leq \xi \leq \xi_k, t \geq 0\}$ (where $\xi_k = \ln \frac{r_k}{r_w}$). In this domain, we introduce a computational grid:

$$\{(\xi_i, t_j): \xi_i = i\Delta\xi; t_j = j\tau; i = 0, 1, 2, \dots, N; j = 0, 1, 2, \dots\}$$

where $\Delta\xi$ and τ are the discretization steps of the computational domain with respect to the variables ξ and t , respectively; N is the number of grid intervals with respect to the variable ξ [8, 9].

By applying integral-interpolation approximation to the equations of unsteady inflow of the gas-condensate mixture (1) and conventional approximation to relations (2) in this discrete domain, a system of linear algebraic equations with a tridiagonal main matrix was obtained to determine the reservoir pressure, condensate saturation, as well as the porosity and permeability of the reservoir. For the unique solution of this system of equations, the initial and boundary conditions (3)-(5) were additionally replaced by their discrete analogues on the embedded grid [18]. To solve the initial and boundary conditions of the resulting system of finite-difference equations using these difference analogues by the tridiagonal matrix algorithm [20], the following iterative process (6)-(9) was obtained:

$$p_{i-1}^{j+1, \nu} = A_{i-1}^{j+1, \nu} p_i^{j+1, \nu} + C_{i-1}^{j+1, \nu}, \quad i = N-1, \dots, 1, \quad j = 0, 1, 2, \dots, \quad \nu = 1, 2, \dots \quad (6)$$

$$\begin{aligned} A_i^{j+1, \nu} &= \frac{K_{li}^{j+1, \nu}}{K_{li}^{j+1, \nu} + K_{2i}^{j+1, \nu}(1 - A_{i-1}^{j+1, \nu}) + \Phi_{li}^j - \Phi_{0i}^j \Phi_{2i}^j}; \\ C_i^{j+1, \nu} &= \frac{K_{2i}^{j+1, \nu} C_{i-1}^{j+1, \nu} + p_i^j (\Phi_{li}^j - \Phi_{0i}^j \Phi_{2i}^j) - (m_i^{j+1} - m_i^j) \cdot (\Phi_{3i}^j - \Phi_{0i}^j \Phi_{4i}^j)}{K_{li}^{j+1, \nu} + K_{2i}^{j+1, \nu}(1 - A_{i-1}^{j+1, \nu}) + \Phi_{li}^j - \Phi_{0i}^j \Phi_{2i}^j}; \\ & \quad i = 1, 2, \dots, N-1 \end{aligned} \quad (7)$$

$$m_i^{j+1} = m_0 e^{\beta_i (p_i^{j+1, \nu} - p_0)}; \quad (8)$$

$$\rho_{ki}^{j+1} = \rho_{ki}^j - \frac{\Psi_{2i}^j}{\Phi_{5i}^j} - \frac{\Phi_{2i}^j \Psi_{3i}^j}{\Phi_{5i}^j (\Phi_{1i}^j - \Phi_{0i}^j \Phi_{2i}^j)} - \frac{\Phi_{4i}^j}{\Phi_{5i}^j} (m_i^{j+1} - m_i^j) \quad (9)$$

where

$$\begin{aligned} A_0^{j+1, \nu} &= \frac{1}{1 + \frac{C^* \Delta \xi}{\tau (F_{2g0}^{j+1, \nu-1} + F_{2k0}^{j+1, \nu-1})}}; \\ C_0^{j+1, \nu} &= \frac{C^* \Delta \xi p_0^j}{\tau (F_{2g0}^{j+1, \nu-1} + F_{2k0}^{j+1, \nu-1}) \left(1 + \frac{C^* \Delta \xi}{\tau (F_{2g0}^{j+1, \nu-1} + F_{2k0}^{j+1, \nu-1})} \right)} - \\ &\quad \frac{q^{*j+1} \Delta \xi}{\left(1 + \frac{C^* \Delta \xi}{\tau (F_{2g0}^{j+1, \nu-1} + F_{2k0}^{j+1, \nu-1})} \right) (F_{2g0}^{j+1, \nu-1} + F_{2k0}^{j+1, \nu-1})}; \\ p_N^{j+1, \nu} &= p_{N-1}^{j+1, \nu-1}; \quad p_{N-1}^{j+1, \nu} = \frac{C_{N-1}^{j+1, \nu}}{1 - A_{N-1}^{j+1, \nu}}; \\ p_i^{j+1, 0} &= p_i^j; \quad \rho_{ki}^{j+1, 0} = \rho_{ki}^j; \quad p_i^0 = p_0; \quad m_i^0 = m_0; \quad \rho_{ki}^0 = 0; \\ K_{li}^{j+1, \nu} &= \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} (F_{1gi+1/2}^{j+1, \nu-1} + F_{1ki+1/2}^{j+1, \nu-1}) + \\ &\quad + \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} \Phi_0^j (F_{2gi+1/2}^{j+1, \nu-1} + F_{2ki+1/2}^{j+1, \nu-1}); \\ K_{2i}^{j+1, \nu} &= \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} (F_{1gi-1/2}^{j+1, \nu-1} + F_{1ki-1/2}^{j+1, \nu-1}) + \\ &\quad + \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} \Phi_0^j (F_{2gi-1/2}^{j+1, \nu-1} + F_{2ki-1/2}^{j+1, \nu-1}); \\ \Phi_{0i}^j &= \frac{S_k(p_i^j) - p_i^j \beta (1 - c(p_i^j) \bar{\gamma}(p_i^j))}{a_k(p_i^j) - \frac{z(p_i^j) \cdot p_{atm}}{z(p_i^j) \cdot p_{atm}}}; \\ \Phi_{li}^j &= \frac{m_i^j (1 - \rho_{ki}^j)}{z^2(p_i^j) p_{atm}}; \end{aligned}$$

$$\left[\beta z(p_i^j) (1 - c(p_i^j) \bar{\gamma}(p_i^j)) - p_i^j \left(c'(p_i^j) \bar{\gamma}(p_i^j) + c(p_i^j) [\bar{\gamma}(p_i^j)]' \right) \right] + \\ + \frac{S'_k(p_i^j) a_k(p_i^j) - S_k(p_i^j) a'_k(p_i^j)}{a_k^2(p_i^j)} m_i^j \rho_{ki}^j;$$

$$\Phi_{2i}^j = \frac{m_i^j (1 - \rho_{ki}^j)}{z^2(p_i^j) p_{atm}} \left[\beta z(p_i^j) (c(p_i^j) + p_i^j c'(p_i^j)) - \beta p_i^j z'_k(p_i^j) \right] - \\ - \frac{a'_k(p_i^j)}{a_k^2(p_i^j)} m_i^j \rho_{ki}^j;$$

$$\Phi_{3i}^j = \frac{\beta p_i^j (1 - c(p_i^j) \bar{\gamma}(p_i^j)) (1 - \rho_{ki}^j)}{z(p_i^j) p_{atm}} + \frac{S_k(p_i^j) \rho_{ki}^j}{a_k(p_i^j)};$$

$$\Phi_{4i}^j = \frac{\beta p_i^j c(p_i^j) (1 - \rho_{ki}^j)}{z(p_i^j) p_{atm}} + \frac{\rho_{ki}^j}{a_k(p_i^j)};$$

$$\Phi_{5i}^j = \frac{m_i^j}{a_k(p_i^j)} - \frac{m_i^j p_i^j \beta c(p_i^j)}{z(p_i^j) p_{atm}};$$

$$\begin{aligned} \Psi_{li}^j &= \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} (F_{1gi+1/2}^j + F_{1ki+1/2}^j) (p_{i+1}^j - p_i^j) - \\ &\quad - \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} (F_{1gi-1/2}^j + F_{1ki-1/2}^j) (p_i^j - p_{i-1}^j); \end{aligned}$$

$$\begin{aligned} \Psi_{2i}^j &= \frac{e^{-2\xi_i} \tau}{(\Delta \xi)^2 r_w^2} (F_{2gi+1/2}^j + F_{2ki+1/2}^j) (p_{i+1}^j - p_i^j) - \\ &\quad - \frac{e^{-2\xi_i} \tau}{\tau (\Delta \xi)^2 r_w^2} (F_{2gi-1/2}^j + F_{2ki-1/2}^j) (p_i^j - p_{i-1}^j); \end{aligned}$$

$$\Psi_{3i}^j = \Psi_{li}^j - \Phi_{0i}^j \Psi_{2i}^j - (m_i^{j+1} - m_i^j) \cdot (\Phi_{3i}^j - \Phi_{0i}^j \Phi_{4i}^j);$$

$$F_{1gi+1/2}^{j+1, \nu-1} = \frac{2F_{1gi}^{j+1, \nu-1} F_{1gi+1}^{j+1, \nu-1}}{F_{1gi}^{j+1, \nu-1} + F_{1gi+1}^{j+1, \nu-1}}; \quad F_{1ki+1/2}^{j+1, \nu-1} = \frac{2F_{1ki}^{j+1, \nu-1} F_{1ki+1}^{j+1, \nu-1}}{F_{1ki}^{j+1, \nu-1} + F_{1ki+1}^{j+1, \nu-1}};$$

$$F_{2gi+1/2}^{j+1, \nu-1} = \frac{2F_{2gi}^{j+1, \nu-1} F_{2gi+1}^{j+1, \nu-1}}{F_{2gi}^{j+1, \nu-1} + F_{2gi+1}^{j+1, \nu-1}}; \quad F_{2ki+1/2}^{j+1, \nu-1} = \frac{2F_{2ki}^{j+1, \nu-1} F_{2ki+1}^{j+1, \nu-1}}{F_{2ki}^{j+1, \nu-1} + F_{2ki+1}^{j+1, \nu-1}};$$

$$F_{1gi}^{j+1, \nu-1} = \frac{k(p_i^{j+1, \nu-1}) F_g(\rho_{ki}^{j+1, \nu-1}) p_i^{j+1, \nu-1} \beta (1 - c(p_i^{j+1, \nu-1}) \bar{\gamma}(p_i^{j+1, \nu-1}))}{\mu_g(p_i^{j+1, \nu-1}) z(p_i^{j+1, \nu-1}) p_{atm}};$$

$$F_{1ki}^{j+1, \nu-1} = \frac{k(p_i^{j+1, \nu-1}) F_k(\rho_{ki}^{j+1, \nu-1}) S_k(p_i^{j+1, \nu-1})}{\mu_k(p_i^{j+1, \nu-1}) a_k(p_i^{j+1, \nu-1})};$$

$$F_{1gi+1}^{j+1, \nu-1} = \frac{k(p_{i+1}^{j+1, \nu-1}) F_g(\rho_{ki+1}^{j+1, \nu-1}) p_{i+1}^{j+1, \nu-1} \beta (1 - c(p_{i+1}^{j+1, \nu-1}) \bar{\gamma}(p_{i+1}^{j+1, \nu-1}))}{\mu_g(p_{i+1}^{j+1, \nu-1}) z(p_{i+1}^{j+1, \nu-1}) p_{atm}};$$

$$F_{1ki+1}^{j+1, \nu-1} = \frac{k(p_{i+1}^{j+1, \nu-1}) F_k(\rho_{ki+1}^{j+1, \nu-1}) S_k(p_{i+1}^{j+1, \nu-1})}{\mu_k(p_{i+1}^{j+1, \nu-1}) a_k(p_{i+1}^{j+1, \nu-1})};$$

$$F_{2gi}^{j+1, \nu-1} = \frac{k(p_i^{j+1, \nu-1}) F_g(\rho_{ki}^{j+1, \nu-1}) p_i^{j+1, \nu-1} \beta c(p_i^{j+1, \nu-1})}{\mu_g(p_i^{j+1, \nu-1}) z(p_i^{j+1, \nu-1}) p_{atm}};$$

$$F_{2ki}^{j+1, \nu-1} = \frac{k(p_i^{j+1, \nu-1}) F_k(\rho_{ki}^{j+1, \nu-1})}{\mu_k(p_i^{j+1, \nu-1}) a_k(p_i^{j+1, \nu-1})};$$

$$F_{2gi+1}^{j+1, \nu-1} = \frac{k(p_{i+1}^{j+1, \nu-1}) F_g(\rho_{ki+1}^{j+1, \nu-1}) p_{i+1}^{j+1, \nu-1} \beta c(p_{i+1}^{j+1, \nu-1})}{\mu_g(p_{i+1}^{j+1, \nu-1}) z(p_{i+1}^{j+1, \nu-1}) p_{atm}};$$

$$F_{2ki+1}^{j+1, \nu-1} = \frac{k(p_{i+1}^{j+1, \nu-1}) F_k(\rho_{ki+1}^{j+1, \nu-1})}{\mu_k(p_{i+1}^{j+1, \nu-1}) a_k(p_{i+1}^{j+1, \nu-1})};$$

$$k(p_i^{j+1, \nu-1}) = k_0 e^{\alpha_k (p_i^{j+1, \nu-1} - p_0)}; \quad k(p_{i+1}^{j+1, \nu-1}) = k_0 e^{\alpha_k (p_{i+1}^{j+1, \nu-1} - p_0)};$$

$$C^* = \frac{C}{2\pi h}; \quad q^{*j+1} = \frac{q^{j+1}}{2\pi h}$$

First, in accordance with the forward sweep of the tridiagonal matrix algorithm, for the index ν ($\nu=1, 2, \dots$), the coefficients $A_i^{j+1, \nu}$ and $C_i^{j+1, \nu}$ are recursively calculated according to formulas (7) for each index j and i ($j=0, 1, 2, \dots; i=0, 1, 2, \dots, N-1$). Then, during the backward sweep of the tridiagonal matrix algorithm, the reservoir pressure values (i.e., the values of p_i^{j+1}), as well as the condensate saturation, porosity, and reservoir permeability coefficients, are calculated for each index j and i ($j=0, 1, 2, \dots; i=0, 1, 2, \dots, N-1$), and the iterative process continues in this manner.

The calculations at each $j+1$ -th time layer at all grid nodes ξ_i continue until inequality is satisfied [20]:

$$\max_i |p_i^{j+1, \nu} - p_i^{j+1, \nu-1}| \leq \varepsilon \quad \text{or}$$

$$\max_i \left| \frac{p_i^{j+1, \nu} - p_i^{j+1, \nu-1}}{p_i^{j+1, \nu}} \right| \leq \varepsilon \quad \nu = 1, 2, \dots$$

(where ε is the required computational accuracy).

3. Numerical calculation and analysis of the results

Based on the specified algorithmic sequence, numerical calculations were performed under the following initial data [7]:

$$\begin{aligned}
p_0 &= 40 \cdot 10^6 \text{ Pa}; q = 100 \text{ m}^3 / \text{day}; m_0 = 0.2; r_w = 0.1 \text{ m}; \\
r_k &= 750 \text{ m}; \beta = 0.81; C = 0; C = 0.5 \cdot 10^{-5} \text{ m}^3 / \text{Pa}; \\
C &= 1 \cdot 10^{-5} \text{ m}^3 / \text{Pa}; p_{atm} = 10^5 \text{ Pa}; \beta_r = 2.5 \cdot 10^{-9} \text{ Pa}^{-1}; \\
\alpha_k &= 0; k_0 = 0.05 \cdot 10^{-12} \text{ m}^2; h = 10 \text{ m}; \\
F_g &= 2.0833 \cdot \rho_k^4 + 4.9167 \cdot \rho_k^3 - 5.5708 \cdot \rho_k^2 - 0.277 \cdot \rho_k + 0.882; \\
F_k &= 1.8864 \cdot \rho_k^2 + 0.1889 \cdot \rho_k + 0.0005; \\
z(p) &= 1 - 0.1162 \cdot 10^{-2} \cdot p + 0.3744 \cdot 10^{-5} \cdot p^2 - \\
&\quad - 0.2965 \cdot 10^{-9} \cdot p^3 - 0.1975 \cdot 10^{-11} \cdot p^4; \\
S_k(p) &= 0.8143 \cdot p; a_k(p) = \\
&= 1.116 + 0.1157 \cdot 10^{-2} p + 0.23674 \cdot 10^{-6} p^2; \\
c(p) &= 0.637 \cdot 10^{-4} - 0.5057 \cdot 10^{-6} p + 0.6265 \cdot 10^{-8} p^2 - \\
&\quad - 0.1595 \cdot 10^{-10} p^3 + 0.13 \cdot 10^{-13} p^4; \\
\gamma(p) &= 194.89 - 0.42974 \cdot 10^{-1} p + 0.1335 \cdot 10^{-4} p^2 - \\
&\quad - 0.6053 \cdot 10^{-6} p^3 + 0.622 \cdot 10^{-9} p^4; \\
\mu_g(p) &= 0.0126 + 0.257 \cdot 10^{-4} p + 0.1633 \cdot 10^{-7} p^2, 10^{-3} \text{ Pa} \cdot \text{sec}; \\
\mu_k(p) &= 0.6 + 0.3295 \cdot 10^{-2} \cdot p + 0.1044 \cdot 10^{-4} p^2 - \\
&\quad - 0.1558 \cdot 10^{-7} p^3 + 0.85 \cdot 10^{-11} p^4, 10^{-3} \text{ Pa} \cdot \text{sec}
\end{aligned}$$

The calculation results are presented in figures 1–4 and tables 1 and 2. Figures 1 and 2, respectively, present, for the value of the wellbore volume effect coefficient equal to $1 \cdot 10^{-5} \text{ m}^3/\text{Pa}$, the curves of changes in reservoir pressure and

condensate saturation throughout the reservoir at different development times.

As can be seen from figure 2, since a relatively high value was specified for the daily condensate production rate, the area with a high condensate saturation value covers a relatively large portion of the reservoir, and as the reservoir pressure decreases, the condensate saturation in this area increases.

Figures 3 and 4, respectively, show the curves representing the variation in the difference between reservoir pressure values obtained with and without accounting for the influence of the wellbore volume across the reservoir for the cases of $C=0.5 \cdot 10^{-5} \text{ m}^3/\text{Pa}$ and $C=1 \cdot 10^{-5} \text{ m}^3/\text{Pa}$ at $t=100$ and 200 days.

Figures 3 and 4 show that the influence of the wellbore volume on the reservoir pressure is more pronounced at higher values of the wellbore volume. Moreover, this influence is greatest at the bottomhole and at longer reservoir development times (in this case, at $t=200$ days, up to 2.3 atm). This is also confirmed by the data presented in table 1, which shows the changes in bottomhole pressure over time at different values of the wellbore volume effect coefficient. The table shows that even at $t=240$ days of well operation, the influence of the wellbore volume reaches 4 atmospheres. It can be expected that, as the bottomhole pressure decreases from 159 atmospheres at $C=0$, this difference will become even more pronounced.

Table 2 presents the changes in the bottomhole condensate saturation over time at different values of the wellbore volume influence coefficient. The table shows that up to a cer-

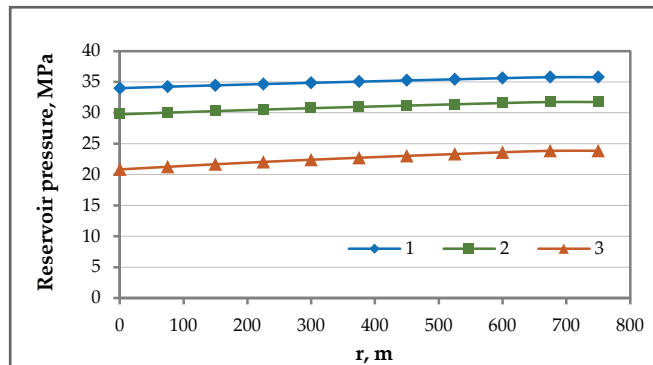


Fig. 1. Variation of reservoir pressure across the reservoir at different development times (for $C=1 \cdot 10^{-5} \text{ m}^3/\text{Pa}$):
1– $t=50$ days; 2– $t=100$ days; 3– $t=200$ days

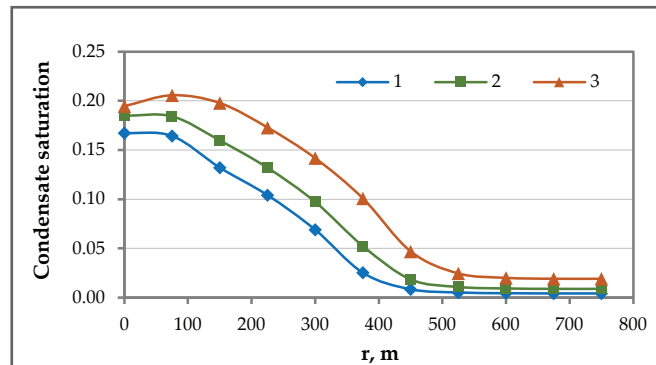


Fig. 2. Variation of condensate saturation across the reservoir at different development times (for $C=1 \cdot 10^{-5} \text{ m}^3/\text{Pa}$):
1– $t=50$ days; 2– $t=100$ days; 3– $t=200$ days

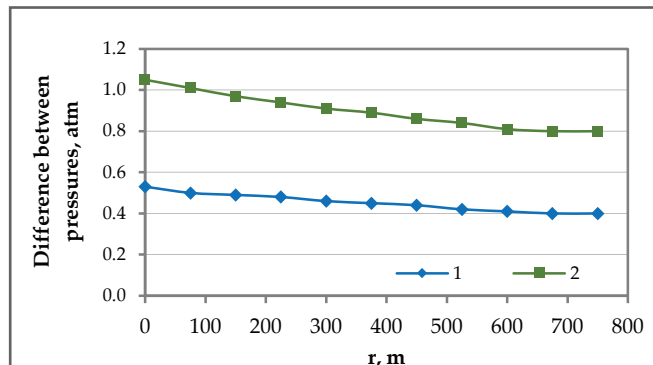


Fig. 3. Variation in the difference between reservoirs pressure values obtained with and without accounting for the influence of the wellbore volume at $t=100$ days:
1– $C=0.5 \cdot 10^{-5} \text{ m}^3/\text{Pa}$; 2– $C=1 \cdot 10^{-5} \text{ m}^3/\text{Pa}$

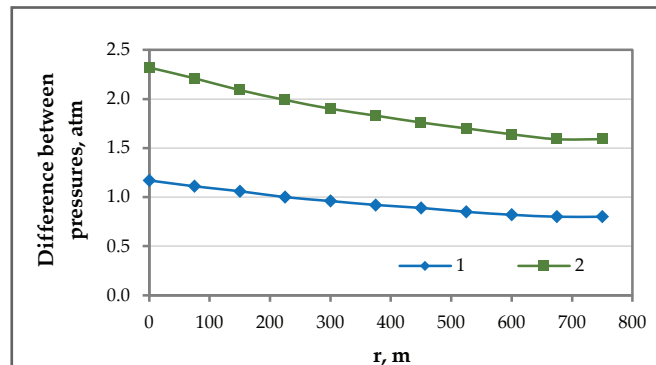


Fig. 4. Variation in the difference between reservoirs pressure values obtained with and without accounting for the influence of the wellbore volume at $t=200$ days:
1– $C=0.5 \cdot 10^{-5} \text{ m}^3/\text{Pa}$; 2– $C=1 \cdot 10^{-5} \text{ m}^3/\text{Pa}$

Table 1
Changes in bottomhole pressure over time at different values of the wellbore volume effect coefficient

Time, days	Bottomhole pressure, 10^5 Pa		
	C=0	C=0.5·10 ⁻⁵ m ³ /Pa	C=1·10 ⁻⁵ m ³ /Pa
1	383.31	383.57	383.91
5	379.22	379.39	379.56
10	374.65	374.84	375.03
20	365.62	365.85	366.08
40	347.91	348.22	348.52
80	313.44	313.89	314.33
120	279.31	279.92	280.52
140	261.99	262.69	263.38
160	244.22	245.04	245.84
200	205.94	207.11	208.26
240	159.00	161.05	163.01

Table 2
Changes in the bottomhole condensate saturation of the reservoir over time at different values of the wellbore volume effect coefficient

Time, days	Bottomhole condensate saturation values		
	C=0	C=0.5·10 ⁻⁵ m ³ /Pa	C=1·10 ⁻⁵ m ³ /Pa
1	0.07016	0.06507	0.05962
5	0.14812	0.14801	0.14790
10	0.15043	0.15031	0.15019
20	0.15476	0.15461	0.15446
40	0.16355	0.16335	0.16315
80	0.17914	0.17888	0.17861
120	0.19032	0.19004	0.18977
140	0.19391	0.19364	0.19338
160	0.19600	0.19576	0.19552
200	0.19477	0.19466	0.19455
240	0.18203	0.18246	0.18285

tain point in time (in this case, up to 200 days), the wellbore volume influence factor reduces the bottomhole condensate saturation compared with the case where it is not taken into account. However, starting from this point in time (at the final stage of well operation), it increases the bottomhole condensate saturation. This is primarily explained by the observed increase followed by a decrease in the bottomhole condensate saturation, both in cases where the influence of the wellbore volume is taken into account and in cases where this influence is not taken into account. At this stage, naturally, the initial increase characterized by a low value is replaced, during the decline stage, by a decrease characterized by a high value.

The calculation results and their analysis demonstrate the necessity of factoring in the influence of the wellbore volume when calculating the technological performance indicators of well operation. It should be noted that the coefficient C approximately accounts for the influence of the wellbore volume. This coefficient is generally determined taking into account the compressibility coefficients and the formation volume factors of each phase. In this regard, in future studies, it would be more appropriate to approach the determination of field development indicators from this perspective in the case of multiphase flow, taking into account the influence of the wellbore volume (using a generalized wellbore volume effect coefficient).

Conclusion

Based on a binary model of the gas-condensate system, a numerical scheme has been developed for solving the problem of gas-condensate well operation in a nonlinear elastically deformable, deep-lying gas-condensate reservoir, factoring in the influence of the wellbore volume. The practical application of the developed numerical scheme, particularly in the development of deep-lying gas-condensate reservoirs with high reservoir pressure and high gas saturation with condensate, makes it possible to improve the efficiency of their development based on preliminary calculations aimed at selecting the most appropriate technological indicators for their operation.

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