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On the rational bottomhole pressure of well operation for the purpose of improving the performance of gas condensate fields

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Abstract. *Efficient operation of gas condensate wells requires balanced bottomhole pressure management to ensure high productivity while minimizing formation damage and condensate plugging. Gas condensate systems exhibit complex thermodynamic and hydrodynamic behavior, as the initially single-phase reservoir fluid undergoes retrograde condensation as pressure drops below the dew point, resulting in the formation of a liquid phase in the near-wellbore zone. This study presents a comprehensive assessment of the physical processes governing gas condensate movement both in the reservoir and wellbore, focusing on the influence of pressure drop, geomechanical effects, and condensate dropout. To evaluate the optimal operating mode (flow regime), analytical modeling is used to describe the relationship between bottomhole pressure, flow rate, hydraulic resistance, and phase behavior under varying condensation conditions. Particular attention is paid to calculating friction losses using turbulent flow correlations such as the Colebrook-White and Swamee-Jain equations, as well as the role of two-phase flow in amplifying pressure losses.*

The results show that maintaining bottomhole pressure at or slightly above the dew point ensures long-term stable productivity and prevents significant permeability degradation, whereas forced production at low pressures leads to rapid condensate bank formation and irreversible damage.

Keywords. Gas condensate reservoirs · bottomhole pressure · well productivity · hydrodynamic modeling.

Mathematics Subject Classification (2010): 76S05, 76T10

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1 Introduction

Gas condensate fields are complex systems in which the produced fluid is a multicomponent mixture of gas and liquid hydrocarbons, including condensate components dissolved in the gas, as well as water, which are in a single-phase gaseous state under reservoir conditions [20;25]. During the process of fluid production from the reservoir to the wellhead, the pressure, as well as the temperature, decrease significantly. The process of movement of the gas condensate system in the reservoir is accompanied by a continuous decrease in pressure in each elementary volume of the reservoir and the release of the liquid phase from the system. With a decrease in pressure, the produced fluid is prone to retrograde condensation [23]. This process, which consists of the separation of the liquid phase (condensate) during an isothermal drop in pressure, is one of the key factors limiting well productivity and requiring careful optimization. Thus, it can be concluded that, at least in the bottomhole zone of wells, the filtered gas condensate system is in a two-phase aerosol dispersed state [12;13;18].

The main task in the operation of gas condensate fields is to maintain an optimal operating flow regime that would ensure maximum gas and condensate extraction with minimal damage to the reservoir and minimal energy losses in the wellbore, which would also contribute to the high completeness of the use of reserves in the gas condensate zone [2;19]. Determining the potentially optimal value of bottomhole pressure for the best fluid production performance, along with the optimal well operating flow regime, remains a pressing issue [5;27]. This work aims to comprehensively analyze the physical processes affecting the productivity of a gas condensate well and demonstrate their influence using interactive hydrodynamic models to establish optimal well operation parameters (wellhead and bottomhole pressure, flow velocity, hydraulic resistance) using the example of a reservoir with one production well. During the operation of such wells, depending on the value of wellhead pressure, the nature of the fluid flow constantly changes, which is reflected in the change in resistance coefficients both in the near-wellbore zone of the formation and in the well itself.

2 Physical processes in the reservoir and their impact on well performance parameters

The processes occurring in drained formations during gas extraction can significantly alter the productive characteristics of wells [26]. They can be divided into two groups: those that worsen and those that improve the filtration properties of the formation:

1. Factors that reduce productivity (increased resistance)

In-situ condensation: When reservoir pressure drops below the dew point, liquid condensate is released into the pores of the rock in the near-wellbore zone. This liquid blocks the pore channels, which leads to a sharp decrease in phase permeability for gas and, as a consequence, a drop-in flow rate [13;18].

Water breakthrough: The intrusion of bottom or marginal water into the reservoir also blocks pores and reduces gas permeability.

Geomechanical effects: A decrease in reservoir pressure increases the difference between the overburden and reservoir pressures. This leads to an increase in effective stresses in the reservoir rock, which can lead to compaction of the rock and a decrease in its permeability. Throughout the entire period of fluid pumping from the reservoir, if there is no replacement fluid, soil consolidation occurs, which reduces the reservoir's permeability for the produced fluid [22]. Such effects are especially important in the analysis of transient filtration regimes and dynamic changes in the drained zone [14].

2. Factors that improve productivity (reduced resistance)

One of the most effective methods is cleaning the bottomhole zone. During drilling, the bottomhole zone becomes contaminated with clay solution and its filtrate [11]. During optimal well operation, the zone is gradually cleared of these contaminants, which restores and improves its filtration properties. Nevertheless, at the initial stage it is possible to clean it using chemical, thermal or hydrodynamic methods [18;22].

Evaporation of condensed liquids. Under certain conditions, condensate or water previously deposited in the formation can evaporate again, freeing up pore space and increasing permeability.

Gas desorption. When pressure decreases, hydrocarbons previously adsorbed on the reservoir rock surface are released, further contributing to the overall flow rate.

Bottomhole formation zone cleanup is often uneven, resulting in gas breakthroughs only through individual, highly permeable intervals. To stimulate and smooth the inflow profile, near-wellbore zone treatment methods, such as acid or condensate treatments, are used. Comparing the current flow rate with the "potential" flow rate (the estimated flow rate with a fully cleaned bottomhole formation zone) allows one to evaluate the effectiveness of such measures. A detailed review of the mechanisms of gas condensate flow and the influence of pore structure is provided in [6;21].

3 Modeling and analysis of the influence of reservoir parameters

Gas produced from a well enters the bottomhole zone in a certain volume and filters through the formation at a limited velocity. The equation of gas inflow to the bottomhole of a gas well is described by a binomial equation that takes into account inertial effects (turbulence), which can be presented in general form [1;11;26]:

$$P_{rp.aver}^2 - P_{bh.aver}^2 = A \cdot Q_{aver} + B \cdot Q_{aver}^2 \tag{3.1}$$

$P_{rp.aver}-$ average reservoir pressure in the deposit;$P_{bh.aver}-$ average bottomhole pressure; A and B - average coefficients of viscous and inertial filtration resistance, respectively. These coefficients increase sharply when condensate forms in the near-wellbore zone; they are often determined empirically, but can be estimated, for example, by the following well-known expressions [1]:

$$A = \frac{1422 \cdot \mu Z T}{kh}\left[lg\left(\frac{R_e}{r_w}\right) - 0.75 + s\right] \tag{3.2}$$

$$B = \frac{1422 \cdot \mu Z T}{kh} D$$

D - this is an empirical turbulence coefficient that depends on the permeability and porosity of the formation.

These coefficients can also be estimated on the basis of observations during the well operation t [15]:

$$A = A_0 + 0.04\lg\left(\tau + 1\right) \tag{3.3}$$

$$B = B_0(\tau + 1)^n$$

A_0 and B_0- the same coefficients at $\tau = 0$. $n-$ correction coefficient determined empirically.

A high value of these coefficients indicates increased resistance to fluid flow, which may indicate contamination of the wellbore bottomhole zone or accumulation of condensate.

A modified productivity index for gas wells can be written:

$$\eta_{gas} = \frac{Q}{P^2_{rp.aver} + P^2_{bh.aver}} = \frac{1}{A + B \cdot Q_{aver}} \quad (3.4)$$

Which, however, is a variable quantity, changing with flow rate Q_{aver}. Thus, for a gas well, the parameter η gas decreases with increasing flow rate Q_{sp} due to the increasing influence of turbulent resistance $B \cdot Q_{aver}$.

To achieve flow rate at the wellhead, it is necessary to regulate the optimal bottomhole pressure so that the bottomhole pressure is less than the formation pressure. However, to prevent condensate formation, the difference between the formation and bottomhole pressures should not be less than the dew point pressure. The following equation determines the relationship between bottomhole pressure and wellhead pressure [7]:

$$P_{bh}{}^2 = P_{wh}{}^2 \cdot e^{2\alpha L} + 1.377 \cdot \lambda \cdot \frac{Z^2_{aver} \cdot T_{aver}{}^2 \cdot (1 + K_{aver})^{\alpha} \cdot \rho^2_{urc}}{\rho^2_{rta} \cdot d^5} \cdot (e^{2\alpha L} - 1) \cdot Q^2 \quad (3.5)$$

where:

$$\alpha = \frac{0.03415\rho_{aver}}{Z_{aver}T_{aver}(1 + K_{aver})}$$

α— a parameter that takes into account the hydrostatic pressure of the gas column.

P_{bh}, P_{wh} — bottomhole and wellhead pressure, Pa.

L is the length of the well, m. (In the calculations below, L will be taken as 1000 m)

d — internal diameter of the pipe, m.

Q — gas flow rate, m/s.

λ is the coefficient of hydraulic resistance (friction), dimensionless.

Z aver , T aver — average supercompressibility and temperature coefficients for the barrel.

ρ_{urc}— gas density under reservoir conditions, kg/m.

relative density of gas (relative to air).

The key and most difficult to determine parameter in this equation is the drag coefficient λ, which depends on several parameters, including the flow regime.

4 Flow regimes and calculation of the hydraulic resistance coefficient (λ)

The coefficient depends λ on the Reynolds number (Re) and the relative roughness (ε/d) [17]. For the turbulent regime typical for gas wells ($Re > 4000$), it is calculated using the Colebrook -White equation [4] or its explicit Swamee -Jain approximation [24]. The formation of condensate in a pipe (two-phase flow) leads to an increase in hydraulic resistance. In a simplified model, this is taken into account by increasing from 0.02 (dry gas) to 0.05 (gas condensate mixture) [1;3;16].

The flow regime is known to be determined by the Reynolds number (Re):

$$Re = (\rho v d)/\mu$$

where ρ is the gas density, v is the average flow velocity, d is the pipe diameter, μ is the dynamic viscosity of the gas.

Let us consider two flow regimes: a hypothetical laminar regime (which is practically never encountered, but we will take it into account for clarity) and a standard turbulent fluid flow regime.

Laminar flow $(Re < 2300)$: The flow is ordered and layered. Resistance is determined solely by viscosity. The hydraulic resistance coefficient is calculated using the Poiseuille equation:

$$\lambda = \frac{64}{Re} \tag{4.1}$$

Turbulent flow $(Re > 2300)$: The flow is chaotic, with vortices. Drag depends on both the Reynolds number and the pipe wall roughness (ε). Empirical equations are used to calculate it.

Colebrook – White equation [4]:

This is the most accurate and generally accepted equation describing λ in all turbulent regimes. It is implicit, meaning it requires an iterative solution:

$$frac1\sqrt{\lambda} = -2\,lg\left(\frac{e}{3.7D} + \frac{2.51}{Re\sqrt{\lambda}}\right) \tag{4.2}$$

Swamee-Jain equation [24]: this is an explicit and very accurate approximation of the Colebrook-White equation, convenient for direct calculations:

$$lambda = \frac{0.25}{\left[lg\left(\frac{\varepsilon}{3.7D} + \frac{5.74}{Re^{0.9}}\right)\right]^2} \tag{4.3}$$

5 Modeling and analysis of the influence of flow parameters

To analyze the impact of various parameters on bottomhole pressure, a model was developed that takes into account changes in the characteristics of the near-wellbore zone and the wellbore. The model plots the relationship between bottomhole pressure and flow rate (P depend of Q) and the friction coefficient versus the Reynolds number (λ depend of Re).

An analysis of the results in the obtained graphs (Fig. 5.1) shows that the Colebrook-White and Swamee-Jain equations yield virtually identical results for the friction coefficient, confirming the high accuracy of the Swamee-Jain approximation. The hypothetical laminar regime exhibits significantly lower resistance and, consequently, lower bottomhole pressure at high flow rates (and high Reynolds numbers). Gas flow in wells is almost always turbulent.

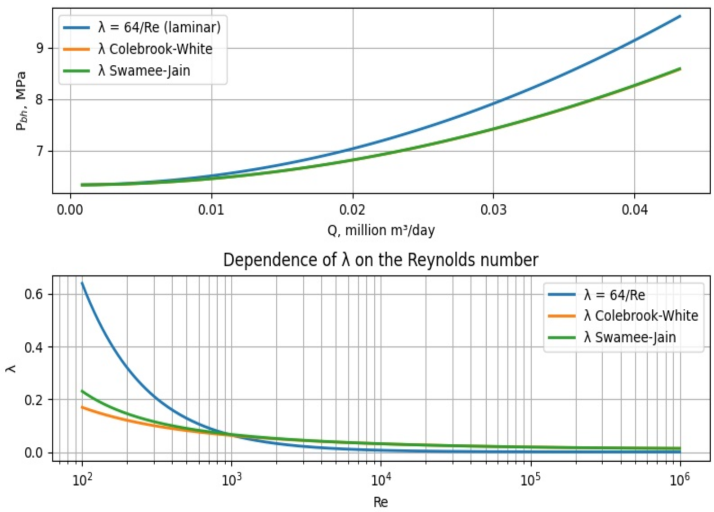

Fig. 5.1 Dependence of bottomhole pressure on gas flow rate ($v = 1.00$ **m/s;** Re $= 800\,000$**;** $\lambda_{\textbf{Colebrook–White}} = 0.0137$**;** $\lambda_{\textbf{Swamee–Jain}} = 0.0138$)

The model also takes into account that an increase in the pipe roughness "ε " or gas viscosity "μ" leads to an increase in the friction coefficient λ. This, in turn, increases pressure losses and requires a higher bottomhole pressure to maintain the same flow rate. It is interesting to note that for some values of ν, μ, ε, and therefore the Reynolds number, the graphs of the dependence of bottomhole pressure on the flow rate in the turbulent regime practically coincide with such a hypothetical laminar case. For example, with a smoother pipe with roughness $\varepsilon = 0.0001$ (The values of the relative roughness of pipelines are given in engineering tables, for example [8]) and the same parameter values ν, μ, we obtain a graph like this (Fig. 2), where all three curves of flow rate change by pressure coincide.

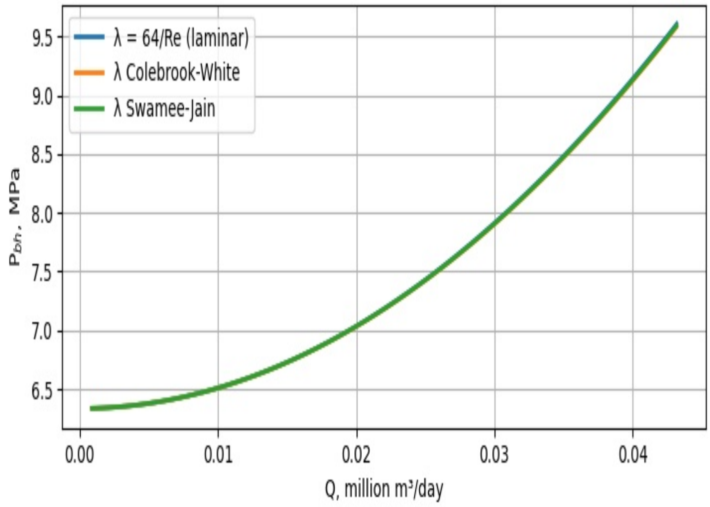

Fig. 5.2 Dependence of bottomhole pressure on gas flow rate with coinciding curves for all three cases ($v = 10.00$ **m/s;** $\mathrm{Re} = 1\,600\,000$**;** $\lambda_{\textbf{Colebrook–White}} = 0.0199$**;** $\lambda_{\textbf{Swamee–Jain}} = 0.0199$**)**

Despite this, it is obvious that in any case only equations that determine the dependence λ on the Reynolds number should be used only for the turbulent flow regime. Although pressure gradients may coincide numerically, the physical flow regimes remain fundamentally different.

6 The influence of condensation on the hydrodynamics of the flow and the physics of the process

The main difficulty of gas condensate systems is the loss of the liquid phase. When the wellbore pressure and temperature drop below the dew point, liquid condensate begins to separate from the gas. This leads to the formation of a two-phase gas-liquid flow, with the following consequences:

Increasing the density and viscosity of the mixture, which increases both the hydrostatic and frictional components of pressure losses.

Increased effective roughness. The liquid film on the pipe walls acts as additional roughness, increasing hydraulic resistance.

Changes in flow structure. Undesirable flow patterns may occur, such as plug flow, which causes pressure pulsations and unstable well operation.

As a result, the equivalent friction coefficient for a gas-condensate mixture (λmix) is always higher than for dry gas under the same conditions. Accurately calculating λmix is extremely complex and requires the use of specialized multiphase flow models.

7 Simplified modeling of two-phase flow

To demonstrate the influence of condensation, a second model was used, which introduces the concept of the average condensation factor (Kaver) - a conditional value reflecting the volume of precipitated liquid.

The model calculates the effective density and viscosity of the mixture and, based on these, determines the bottomhole pressure. For clarity, let's compare two discrete scenarios at a certain section of the well, as proposed in the original analysis:

1) Weak condensation: $\lambda = 0.02, Kaver = 0.0005$.

2) Strong condensation: $\lambda = 0.05, Kaver = 0.01$.

The graph (**Fig. 7.1**) clearly demonstrates that the curve for strong condensation (red) lies significantly higher. This means that pumping the same volume of gas (the same flow rate Q) in the presence of a large amount of liquid phase requires a much higher bottomhole pressure.

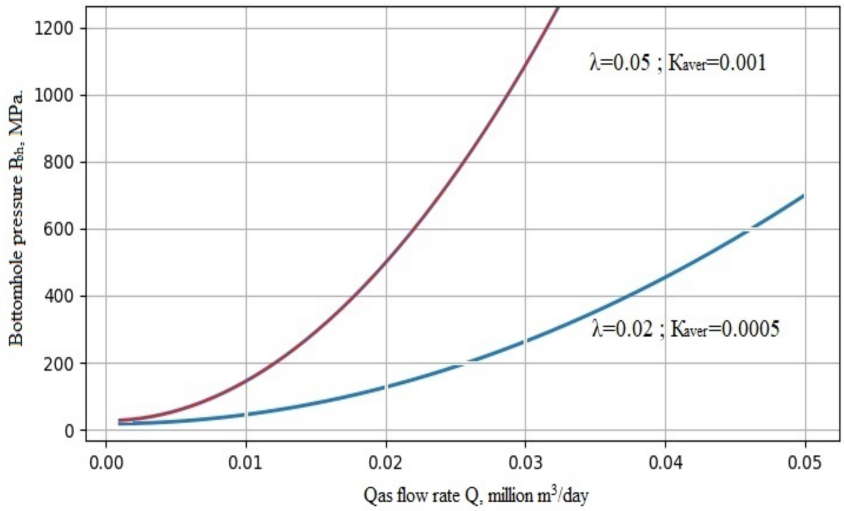

Fig. 7.1 Dependence of bottomhole pressure on gas flow rate

The pressure difference increases nonlinearly with increasing flow rate. This is because friction losses are proportional to the square of the velocity (and, therefore, the flow rate).

This result clearly shows that condensation is the main factor reducing the efficiency of the lift in a gas condensate well, as it directly increases frictional energy losses.

In order to determine the optimal pressure that does not allow excessive condensation in the well, we will construct the following model - For a closed formation with one well, we will accept the following hypothetical parameters (Table 1), characteristic of a gas condensate field [8]:

Table 7.1

Parameter	Designation	Measurment
Average reservoir pressure	P_{rp}	30.0 MPa
Pressure dew point (the threshold pressure at which condensation occurs)	P_{dp}	25.0 MPa
Well depth	L	1000 m

We use the binomial inflow equation $P_{plsp}^2 + P_{z.sp}^2 = A \cdot Q_{sp} + B \cdot Q_{sp}^2$. The change in coefficients A and B reflects the sharp drop in relative gas permeability during condensation (when $P < P$). Assume that when gas flows above the dew point, all condensate is well dissolved in it and the fluid is single-phase. During condensation, however, at pressures below the dew point, the fluid is a two-phase mixture of both the liquid phase and the gas itself. We adopt the coefficients as follows:

Table 7.2

Flow regime	Bottomhole pressure	A	B	State
I (Single-phase)	P $_{bh} >$ 25.0 MPa	A $_1$= 0.1	B $_1$= 0.0001	Gas
II (Two-phase)	P $_{bh}<$ 25.0 MPa	A $_2$= 0.5	B $_2$= 0.0003	Gas And Dropped out condensate

Using equation (3.5) and denoting in it for simplicity the hydrostatic coefficient $e^{2\alpha L} = e^{2s} = 4.0$, as well as part of the expression $1.377 \cdot \lambda \cdot \frac{Z_{aver}^2 \cdot {T_{aver}}^2 \cdot (1+K_{aver})^{\alpha} \cdot \rho_{urc}^2}{\rho_{rta}^2 \cdot d^5} \cdot \left(e^{2aL} - 1\right) = Gas$ as an additional resistance factor, equation (3.5) can be rewritten in general form:

$$
{P_{bh}}^2 = {P_{wh}}^2 \cdot e^{2aL} + 1.377 \cdot \lambda \cdot \frac{Z_{aver}^2 \cdot {T_{aver}}^2 \cdot (1+K_{aver})^{\alpha} \cdot \rho_{urc}^2}{\rho_{rta}^2 \cdot d^5} \cdot (e^{2aL} - 1) \cdot Q^2 \approx
$$

$$
\approx {P_{wh}}^2 \cdot e^{2s} + C \cdot Q^2 \tag{7.1}
$$

From here, we'll consider two distinct well operating modes—rational and forced. In the first case, the well operates primarily in single-phase mode. Permeability damage is minimal. This mode is optimal for long-term operation, as it maintains reservoir productivity. Rational bottomhole pressure is defined as the minimum pressure ensuring single-phase flow in the near-wellbore zone while maintaining long-term reservoir permeability. In the second case, the well operates in two-phase mode. Bottomhole pressure is low. P$_{bh}$ leads to a sharp condensate drop, which causes a significant increase in the A coefficient and a drop in effective permeability. Although the instantaneous flow rate is higher, this will lead to a rapid decline in productivity and overall inefficient use of reserves.

8 Simplified modeling of two-phase flow

Table 8.1

Mode well work	Pressure on wellhead P$_{wh}$)	Coefficient C	Bottomhole pressure P$_{bh}$
1 (Rational)	P $_{wh1}$= 12.5 MPa	5.0 * 10 $^{-5}$	25.0 MPa
2 (Forced)	P $_{wh2}$= 10.0 MPa	1.5 * 10 $^{-4}$	20.0 MPa

Rational production at a gas condensate field in the early stages of operation requires maintaining P dew point above or equal to the dew point (P$_{dp}$ = 25.0 MPa). As can be seen from the graph, in the rational operating mode, the operating point P $_{bh}$ (green dot) is slightly above the dew point pressure (P$_{dp}$). The well operates optimally, maximizing flow rate while maintaining single-phase filtration in the formation. Permeability damage is minimal, ensuring long-term stability of well productivity.

In forced mode, the operating point (red dot) is exactly at or slightly below the dew point. Condensation begins here, and as the well continues to operate and reservoir pressure declines, more condensate will form over time, causing clogging of the wellbore flow in the near-wellbore zone, increasing resistance and reducing well flow. In extreme cases (at very low bottomhole pressure), partial collapse of the near-wellbore zone is even possible, with formation rock material being carried toward the wellhead.

Although the flow rate at this point is temporarily higher (by approximately 165,000 m^3/day) than under rational operation, this is achieved at the cost of irreversible damage to permeability. Due to the condensate deposition, the fluid inflow curve into the near-wellbore zone (blue line) will "bend," and a further reduction in wellhead pressure P_{wh} will not yield a commensurate increase in Q. The corresponding graphs are shown in (**Fig**.8.1).

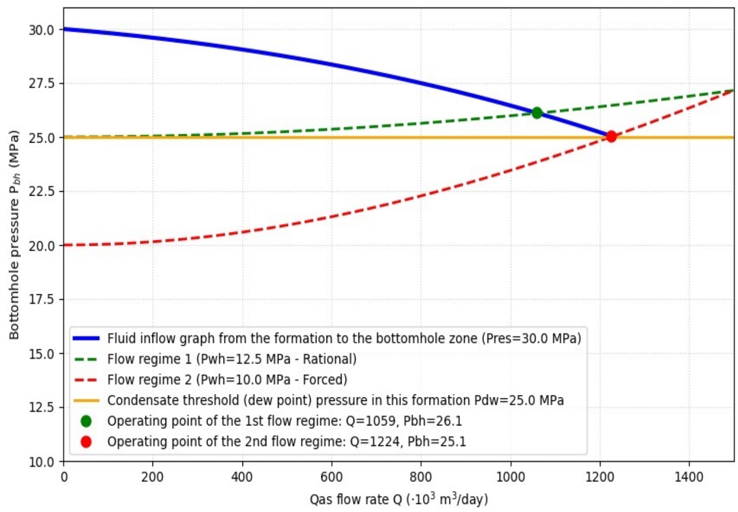

Fig. 8.1 System analysis of the relationship between pressure and flow rate for a gas condensate well

9 Conclusions and recommendations

A comprehensive analysis shows that for the efficient operation of gas condensate wells it is necessary:

Accurate knowledge of the phase diagram, dew point and potential condensate content is the basis for any design and optimization [9;23]. The use of modern improved models allows us to more accurately predict the behavior of the fluid [10]. Rational operation involves maintaining bottomhole pressure at or slightly above the dew point in the early stages of development. This prevents the colmatation of the near-wellbore zone with condensate [19]. During operation, if possible, the well should be operated at bottomhole pressures above the dew point pressure to minimize condensation in the formation. Condensation in the wellbore is inevitable, but its impact can be controlled.

Proper wellbore diameter selection is crucial. Too large a diameter can lead to low flow rates and fluid accumulation at the bottomhole. Too small a diameter can lead to unreasonably high friction losses. Wellbore condition is also crucial; wear and tear and increased roughness dramatically increase hydraulic resistance and alter the fluid flow pattern.

Application of additional protective technologies: for example, in offshore conditions, where cold water enhances condensation, thermal insulation of the column, heating, or the introduction of inhibitors (additional chemical additives), which also affect hydrodynamics, may be required. In conditions of risk of condensation, it is necessary to use methods of maintaining reservoir pressure, thermal insulation of the lift, or the introduction of surfactants to improve fluid removal [1;19]. Another qualitative approach may be the creation of a cyclic hydrodynamic effect in the reservoir to restructure its porous structure along with the movement of parts of the fluid in the pore space, and thus it is also possible to achieve an increase in the fluid recovery from the reservoir [21].

The analysis and modeling conducted confirmed that the productivity of gas condensate wells is determined by the complex interaction of processes in the reservoir and in the wellbore.

Calculating friction pressure losses requires a correct definition of the flow regime and the use of more complex equations (Colebrook -White or Swamee? - Jain) that accurately describe the flow regime for turbulent flow. Condensate loss is a key negative factor, sharply increasing hydraulic resistance and requiring significantly higher bottomhole pressure to maintain flow rate. This fact requires precise control of wellhead pressure to maintain optimal bottomhole pressure. Interactive hydrodynamic models, even simplified ones, are a powerful tool for visualizing and understanding the impact of various physical parameters (roughness, viscosity, condensation) on well performance. Further model sophistication should include numerical integration along the wellbore length with step-by-step calculation of phase equilibrium parameters (Z_{aver}, K_{aver}) and the use of advanced correlations for multiphase flows.

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