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Determination of the D-factor and its effect on the stimulated volume of compact gas-saturated reservoirs

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Abstract. Correct estimation of the possible volume of replacement of conventional reservoir structures with compacted sandstones/carbonates in existing fields and production areas is a controversial issue not only in Ukraine but also abroad, due to parametric uncertainty and the impact of formation fluid filtration in unconventional reservoirs. This leads to an overestimation of the forecasted development of compact gas-saturated reservoirs, a decrease in the replacement rate, and an increase in the rate of production decline. Therefore, the aim of the study was to assess the influence of the coefficient of additional filtration resistance, which occurs due to the high rate of upward fluid flow as one of the key uncertain parameters, on the well productivity and the resulting accumulated gas extraction. A multi-stage hydraulic fracturing was performed in a synthetic horizontal well, which was created in the Petrel software. Using typical correlations, the additional resistance coefficients (D-factor) are determined and a hydrodynamic model is constructed in the Eclipse software. Simulations with different values of the D-factor were performed to determine its effect on productivity on accumulated samples for the same type of formations. The results of the study indicate that the revaluation can reach 40%, which is significant when calculating the economic indicators of the feasibility of drilling and conducting multi-stage hydraulic fracturing. The proposed selection and methodology for low-permeability formations encountered in the fields of the Dnipro-Donetsk Basin of Ukraine can be used by gas and oil companies for a detailed analysis of uncertainties and correct planning of stabilisation of the gas production decline

Keywords: coefficient of additional resistance; fluid filtration; multi-stage hydraulic fracturing; simulation; well flow rate

Introduction

Correct determination of the forecast performance of horizontal wells that penetrate compact reservoirs is critical for development planning and optimisation. The risk of revaluation of accumulated selections causes distrust of investors and partners in joint field development schemes and increases the payback period of projects. Detailed analysis and assessment of such risks is one of the requirements when designing the development of non-traditional collectors. Any minimisation of these risks and the validity of forecast performance indicators of expensive design horizontal wells, with multi-stage hydraulic fracturing, proves the relevance of this topic. J.-Q. Zhou *et al*. (2019b) deduced the relationship between viscous inertial filtration and permeability by synthesising the results of thousands of laboratories and field filtration tests and modelling using a hydrodynamic simulator. Their research showed that

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the permeability of a geological space can vary by several degrees of magnitude under the influence of compression, shear, decompression or fracture. Since these inertial effects are included in the viscosity and filtration components of the Forchheimer equation, their correct description or the use of certain values to compensate for this effect is critical for predicting filtration in cases where filtration and media geometry (fracture formation) evolve simultaneously. Researchers J.-Q. Zhou *et al*. (2019a) proposed a theoretical expression for the definition of permeability as a function of pressure in fracture pore space. Studies have shown that in order to adjust the theoretical dependence on the actual data, the Forchheimer equation and the coefficient of additional resistance were used, since the dependence was characterised by overestimated values on the graphs of the pressure dependence on the flow rate. A.F. Hart & O.C. Omobolanle (2023) considered the possibility of determining the coefficient of additional resistance using the example of a core sample under laboratory conditions for different temperatures – 38, 65 and 93°C. N_2 was used as the agent pumped through the core sample at various temperatures. The results of this study showed that with an increase in pumping temperature and pressure, the coefficient of additional resistance increased, and a decrease in the permeability of the proppant pack was also observed.

B.R. Jones *et al*. (2020) investigated the possibility of predicting filtration at the limit of Darcy's law using the Forchheimer equation for different values of hydrocarbon saturation. The authors have shown that the Forchheimer equation is valid for predicting the flow rates measured on the core. For all experiments, the difference between measurements and predictions was no more than 5% for any pressure interval from all tested models. However, the authors noted that additional quantitative and qualitative studies, both in the laboratory and in the field, are necessary for better predictability. D.S. Berawala & P.Ø. Andersen (2019) determined that the effect of filtering at the Darcy's law boundary is dominant in the cracks, not in the matrix. Production itself is limited by the increased gas content in the fractures as a result of additional resistance due to gas mobility, and the final recovery factor depends more on the size and shape of the fractures created during hydraulic fracturing compared to Darcy's law filtration. Scientists A. Elsanoose *et al*. (2022), attempted to derive a new correlation for determining the coefficient of additional resistance at the limit of Darcy's law using laboratory studies and conducted 358 experiments on 7 large, artificially created prototypes of a porous medium. However, at this stage of research, air and water were used as fluids, and the authors noted the feasibility of repeating experiments using other injection agents, such as CO_2 and hydrocarbon gas. The resulting logarithmic dependence is planned to be used in forecasting the main development indicators for its validation. Although there is already a scientific body of work on this topic, the issue of applying an additional resistance coefficient when assessing the predicted performance of horizontal wells with high upward flow rates using hydrodynamic simulators in the Dnipro-Donetsk Basin (DDB) fields has not been sufficiently considered, which leads to an overestimation of the predicted development indicators when designing horizontal wells. The aim of this study was to build a synthetic model of a compact gas-saturated reservoir developed by a horizontal well with multistage hydraulic fracturing and bring it to the conditions encountered in the DDB fields in order to assess the effect and perform sensitivity analysis on the resulting accumulated samples, after applying an additional coefficient of resistance that occurs due to filtering at the limit of Darcy's law.

Theoretical Overview

The topic of describing fluid filtration in non-traditional reservoirs when developed by horizontal wells in which hydraulic fracturing is carried out has always caused heated discussions. One aspect of these discussions concerns an additional resistance coefficient (D-factor), namely one of its components β, a factor that is also known by some other names. For example, the turbulence factor in research by D. Cornell & D.L. Katz (1953) or the inertia coefficient of H. Ma & D. Ruth (1993). Since the flow rate in the modified equation by P. Forchheimer (1901) is given in the second degree, most researchers focused on high values of flow rates, which usually occurs in the bottom-hole zone of gas condensate wells. Research by F. Zeng & G. Zhao (2010) showed that the use of reasonable values of additional pressure losses due to filtration at the limit of Darcy's law can reduce the resulting well productivity by up to 50%, while the conductivity of cracks after hydraulic fracturing is up to 20%. A significant decrease in well productivity after hydraulic fracturing or in fractured formations has been confirmed by other authors. K.E. Olsen *et al*. (2004) emphasised the importance of optimising the hydraulic fracturing design for wells operating in two or more phases (oil, gas, water) and evaluated the validity of the Forchheimer equation at very high well flow rates. The results showed an overestimation of the accumulated recovery after 400 days of well operation in the range of 25 to 56%, with a suboptimal operating mode and incorrect consideration of the additional resistance factor. The correct description of filtration in gas condensate reservoirs developed by high-flow wells is complicated by the increase in fluid velocity and viscosity due to phase transformations in the bottom-hole zone, as noted by P. Ghahri *et al*. (2011), namely the formation of a condensate shaft, which also affects the performance of horizontal wells, after hydraulic fracturing, when the pressure decreases below the pressure of the beginning of condensation. Also, in the work by D.D. Cramer (2004) it was found that when stimulating low-permeable reservoirs using hydraulic fracturing technology, the effect of reservoir fluid filtration at the limit of Darcy's law also affects the reduction of the resulting semi-lengths (*xf*) formed fractures.

The issue was also highlighted in discussion by D. Van Batenburg & D. Milton-Tayler (2005) on the publication of R.D. Barree & M.V. Conway (2004). This discussion essentially revolves around the limits of the applicability of the Forchheimer equation and the adequacy of its description when filtering fluids in unconventional reservoirs. R.D. Barree & M.V. Conway (2004) summarised that new experimental data, under conditions of high upstream velocity, convincingly showed that the Forchheimer equation, just as Darcy's law. (1865) has a limited range of applications. In turn, D. Van Batenburg & D. Milton-Tayler (2005), after conducting a number of experimental studies, did not agree that the Forchheimer equation cannot be used to describe the dependence of the additional coefficient of resistance on the rate of upstream flow and presented data collected in two laboratories that the proposed Forchheimer equation is valid for most actual and physical ranges of real wells, while the values at which the deviation is observed are far beyond the real modes of well operation. D. Denney (2005) noted that β (which is considered constant for all velocities) can be a variable that depends on the speed. This makes it possible to better describe and control pressure losses, but makes it impossible to accurately predict the flow rate as a function of the pressure gradient. As can be seen after analysing the fundamental works, everything that follows in newer publications refers to the original sources in one way or another and does not directly describe their research, using only the results. In Ukrainian publications, there are almost no examples of the use of this coefficient in the design of horizontal wells. This further confirms the relevance of this study.

Materials and Methods

Modelling, design and successful application of methods for improving oil and gas production directly depends on the correctness of the description of their filtration features. H. Darcy (1865) derived the fundamental law of reservoir fluid flow dynamics in pore space:

$$-\frac{dP}{dx} = \frac{\mu v}{k}, \tag{1}$$

where P – pressure, bar; x – flow direction; μ – dynamic viscosity coefficient, Pa·s; k – permeability of the porous medium, D; v – volume flow rate of liquid, m³/s. According to the equation (1), the volume flow rate is directly proportional to the pressure gradient. Later, experimentally, P. Forchheimer (1901) derived a deviation from the linear proportionality of Darcy's filtration law for high volume flow values. S. Ergun (1952) observed that for high flow rates, the pressure drop is greater than predicted by Darcy's law. This phenomenon has been referred to in the literature as filtering outside of Darcy's law. Forchheimer added an additional pressure loss proportional to the square of the volume flow rate. Therefore, the equation (1) has taken the following form:

$$-\frac{dP}{dx} = \frac{\mu v}{k} + \beta \rho v^2, \tag{2}$$

where β – factor used by Forchheimer for correction, Pa^{-1}; ρ – fluid density, kg/m³. According to the equation (2), the total pressure gradient ($-dp/dx$) can be considered as the sum of the gradients required to overcome the viscosity ($\mu v/k$) and liquid – solid interactions ($\beta \rho v^2$). There is a generally accepted opinion that this effect occurs only in the bottom-hole zone at a distance of up to several meters. This is the main reason why most hydrodynamic simulators describe this effect as an additional skin factor at the well-formation level:

$$S_{total} = s + Dq, \tag{3}$$

where S_{total} – total skin; s – permanent skin factor; D – skin factor coefficient, depending on the filtration rate, D/thousand m³. Coefficient D can be defined as:

$$D = \frac{2.715\times10^{-15}\times\beta M P_{sc} k}{\mu T_{sc} h r_w}, \tag{4}$$

where M – molecular weight, g/mol; P_{sc} – pressure under standard conditions, bar; k – permeability, mD; μ – viscosity, centipoise; T_{sc} – temperature under standard conditions, °C; h – reservoir capacity, m; rw – consolidated well radius, m. In this study, a synthetic hydrodynamic model of a single horizontal well with 5-stage hydraulic fracturing is used. The model is based on compact reservoirs in the DDB. A compositional simulator was used to take into account the phase transformations that occur along the created fractures. Typical correlations that were used in the study are summarised below.

$$\beta = \frac{45185}{\varphi^{1.5} k^{0.5}}; \tag{5}$$

$$\beta = \frac{1.82\times10^{8}}{k^{1.25}\varphi^{0.75}}; \tag{6}$$

$$\beta = \frac{1.58\times10^{3}}{k^{0.5}\varphi^{5.5}}; \tag{7}$$

$$\beta = \frac{1.88\times10^{10}}{\varphi^{-} k^{0.5}}; \tag{8}$$

$$\beta = \frac{4.8\times10^{10}}{k^{1.176}}; \tag{9}$$

$$\beta = \frac{2.018\times10^{9}}{k^{1.55}}; \tag{10}$$

$$\beta = \frac{2.923\times10^{7}}{k\varphi}\tau; \tag{11}$$

$$\beta = \frac{3.51\times10^{10}\varphi^{0.449}}{k^{1.88}}; \tag{12}$$

$$\beta = \frac{8.17\times10^{9}\varphi^{0.537}}{k^{1.79}}; \tag{13}$$

$$\beta = \frac{1.35\times10^{7}\tau^{3.35}}{k^{0.98}\varphi^{0.29}}; \tag{14}$$

$$\beta = \frac{1.01\times10^{8}\tau^{1.943}}{k^{1.023}}; \tag{15}$$

$$\beta = \frac{1.15\times10^{7}}{k\varphi}; \tag{16}$$

$$\beta = \frac{1.1\times10^{9}}{k^{1.11}}; \tag{17}$$

$$\beta = \frac{7.64\times10^{8}}{k^{-1.72}}; \tag{18}$$

$$\beta = \frac{1.429\times10^{3}}{k^{-1.5}\varphi^{-0.5}}, \tag{19}$$

where β – Forchheimer correction factor, Pa^{-1}; k – absolute permeability, mD; φ – porosity, fractions of a unit. It should be noted that several correlations can be applied to the same formation types, while the resulting values of additional pressure loss can differ significantly. In this case, the averaging of D-factor values is often used. Below are the average parameters of the synthetic hydrodynamic model and the results of calculating the values β and D-factor using correlations that are relevant for DDB formations according to H. Saboorian-Jooybari & P. Pourafshary (2015). The values shown in Table 1 are typical for low permeability reservoirs of the DDB. The porosity of 0.24 corresponds to a permeability of only 0.02 mD.

Table 1. Average parameters of the synthetic hydrodynamic model

k, mD	φ	μ, centipoise	*h*, m	*kW*, m	visc.
0.02	0.24	0.02	25	0.75	0.72

Source: created by the authors

The thickness of this reservoir is 25 m, and the reservoir fluid viscosity was determined from the equation of state. The resulting values in Table 2 were used in the hydrodynamic modelling on the synthetic model. The 3D hydrodynamic model was built on the basis of the synthetic well W1, one of the DDB reservoirs.

Table 2. Results of calculations of β and D-factor for various correlation dependencies

Correlation	β	D-factor
(6)	5.34E+10	1.61E-04
(9)	3.68E+12	1.11E-02
(12)	1.71E+13	5.15E-02
(13)	2.80E+12	8.45E-03
(16)	1.92E+09	5.79E-06
(10)	6.14E+11	1.85E-03
(8)	9.07E+12	2.74E-02
(7)	2.58E+07	7.78E-08
(18)	4.35E+11	1.31E-03
(19)	7.69E+04	2.32E-10
Average value	1.02E-02	

Source: created by the authors

This model was used to estimate the effect of additional pressure losses by applying the D-factors calculated in Table 2. A 5-stage hydraulic fracturing system was modelled for this well. Parameters of the resulting fractures, their height (*h*), thickness (*Dw*), half-length (*Xf*) and the resulting permeability (K_{prop}) are shown in Table 3. Visualisation of simulated fractures for well W1 is shown in Figure 1.

Table 3. Fracture parameters

h, m	*Dw*, m	*Xf*, m	w, m	K_{prop}, md
5	0.02	100	0.002	10,000

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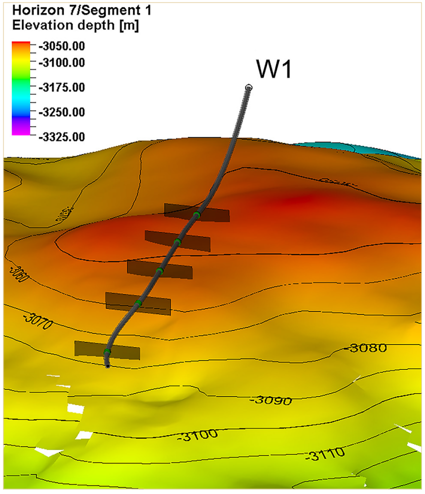

Figure 1. Visualisation of W1 well fractures

Source: created by the authors

The simulation was performed with a downhole pressure limit for well W1, at 180 bar. The initial pressure at the beginning of the simulation is 400 Bar. The reservoir developed by well W1 is composed of low-permeability reservoirs with an average permeability of 0.02 mD, while the average porosity is 0.26. The histograms of the porosity and permeability distribution throughout the reservoir are shown in Figure 2.

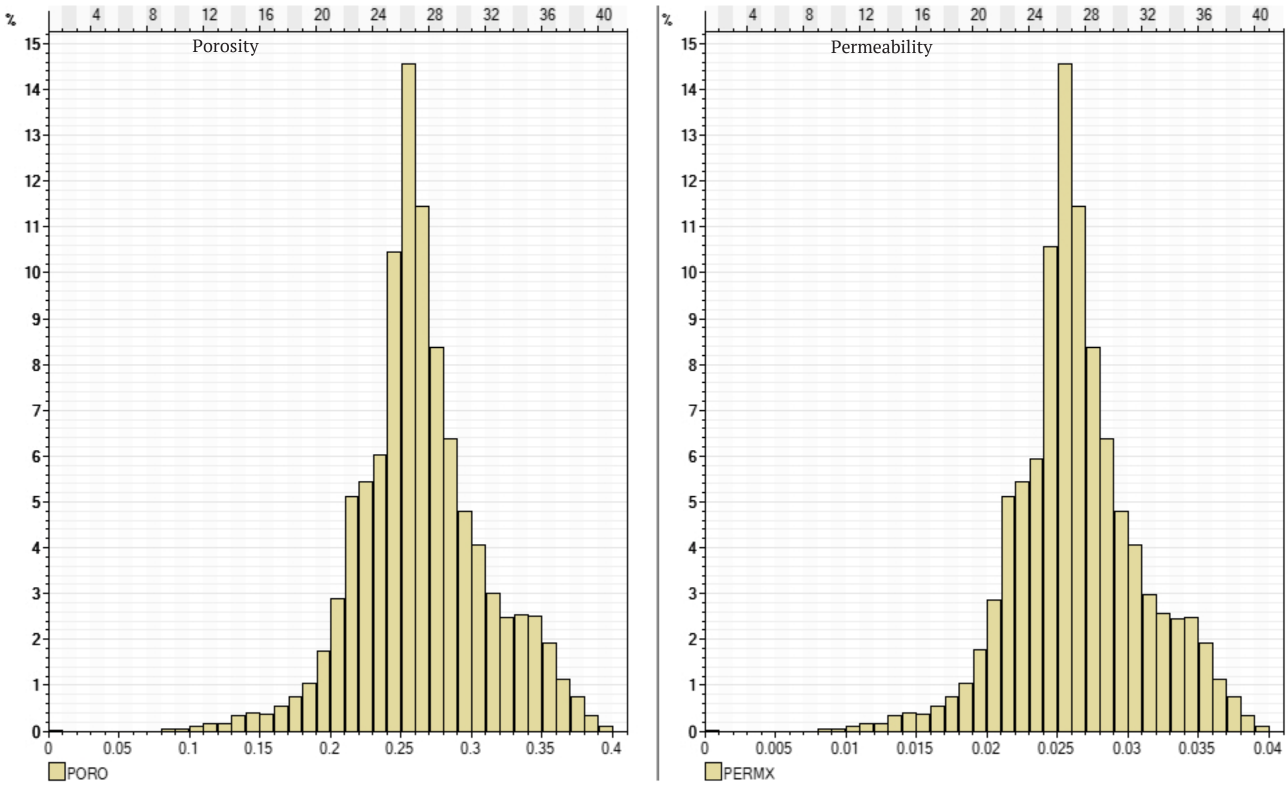

Figure 2. Histograms of porosity and permeability distribution in the formations

Source: created by the authors

The equation of state consists of 15 components, of which 3 are non-hydrocarbon. The composition is shown in Table 4. The equation of state was selected and calibrated in accordance with the behaviour of reservoir fluids under the relevant thermobaric conditions (Tpl – 133°C. Pressure – 400 bar). The results of adjusting the equation of state are shown in Figure 3.

The modified Peng Robinson equation was used as the equation of state. The resulting phase diagram and initial formation conditions are shown in Figure 4.

Table 4. Composition of the equation of state

No.	Component	%, mol
1	CO_2	2.98
2	H_2S	0.80
3	N_2	0.12
4	C_1	74.39
5	C_2	7.94
6	C_3	3.74
7	$I\text{-}C_4$	0.87
8	$N\text{-}C_4$	1.71
9	$I\text{-}C_5$	0.71
10	$N\text{-}C_5$	0.81
11	C_6	0.99
12	C_7	1.97
13	C_8	2.13
14	C_9	0.76
15	C_{10+}	0.08

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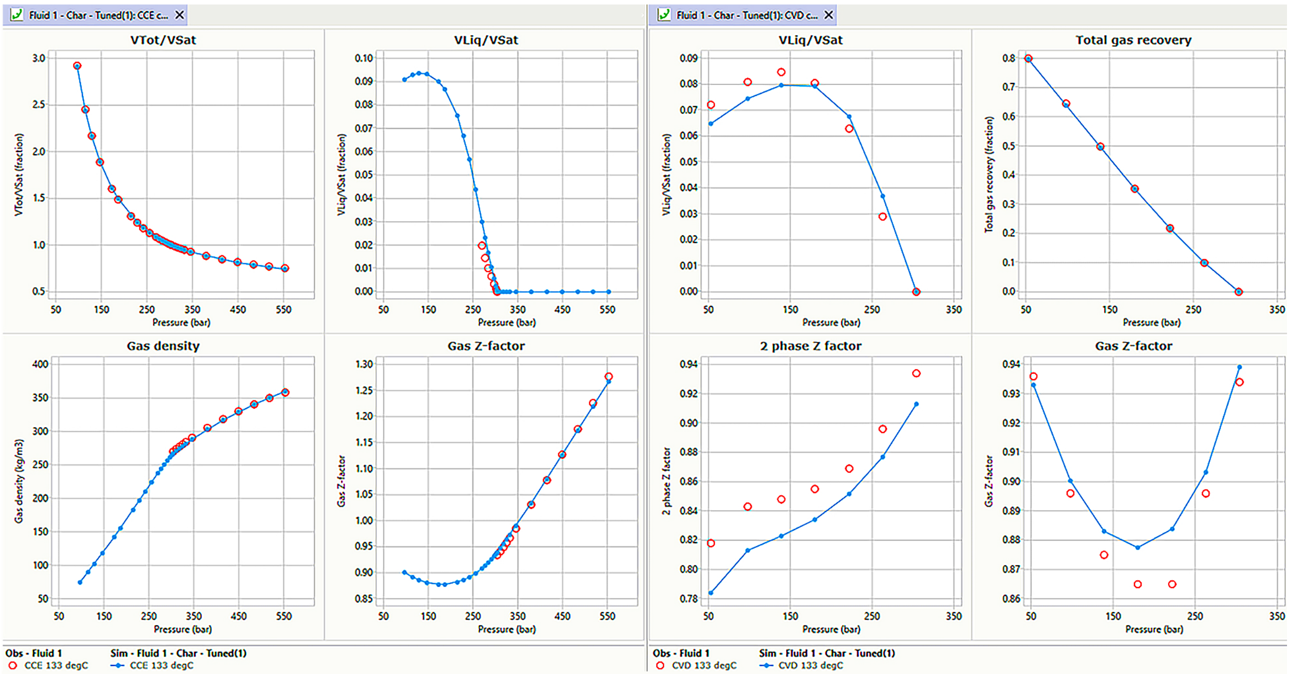

Figure 3. Results of equation of state adjustment,
constant composition expansion and constant volume depletion experiments

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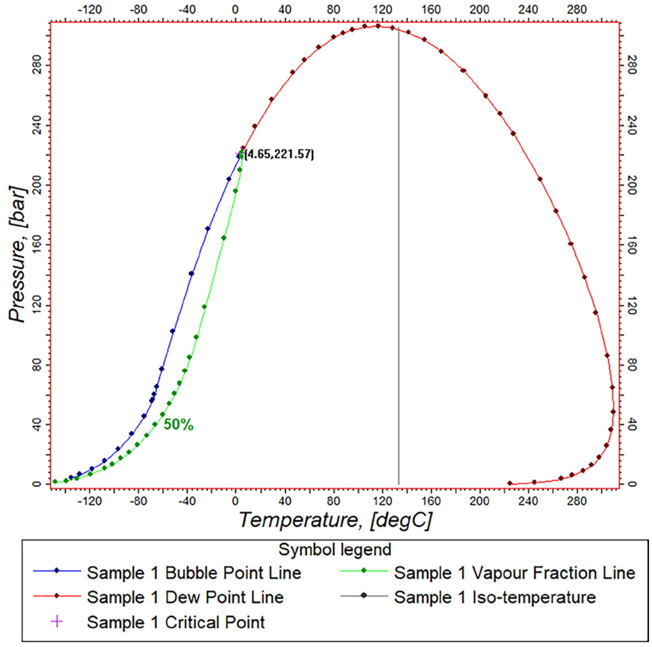

Figure 4. Phase diagram and initial formation conditions

Source: created by the authors

Relative phase permeabilities were used by analogy and were unified for the entire reservoir. Since the deposit is gas-condensate, condensate is taken as oil.

Figure 5 shows a single set of relative phase curves for the oil-water and oil-gas systems used in the model.

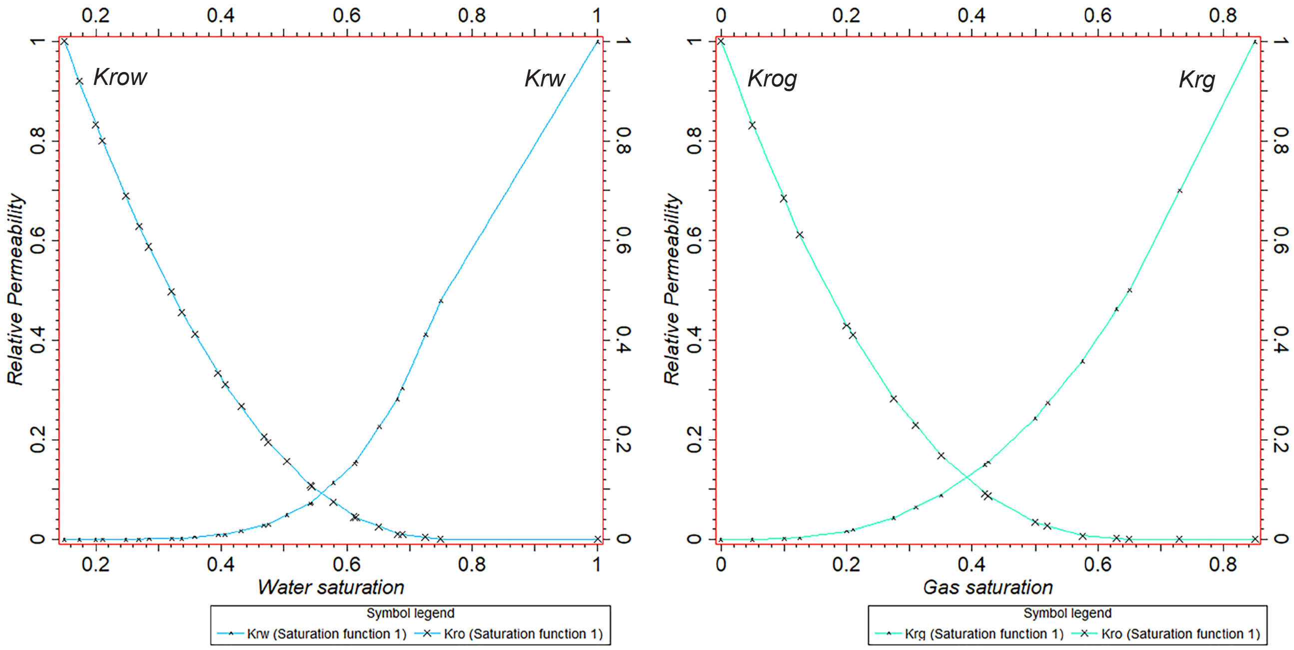

Figure 5. Relative phase permeability (oil-water, oil-gas)

Note: Krow – relative permeability to oil in presence of water; Krw – relative permeability to water; Krog – relative permeability to oil in presence of gas; Krg – relative permeability to gas
Source: created by the authors

Results and Discussion

Initial gas reserves after initialisation of the model amount to 2.7 billion m^3, and initial condensate reserves – 1.05 million m^3. The gas-water contact was established at a depth of –3,130 m. The initial distribution of water saturation is shown in Figure 6.

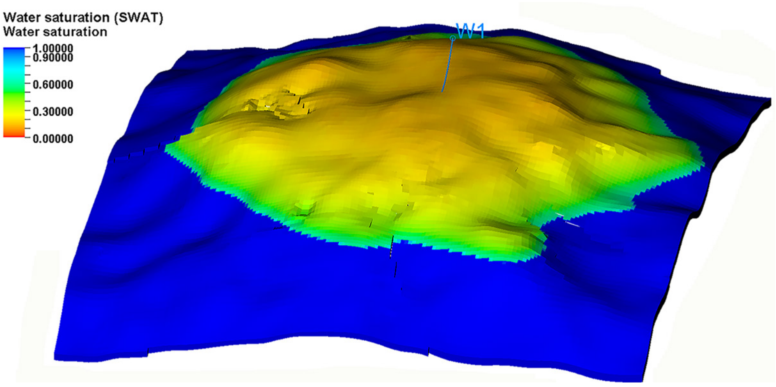

Figure 6. Initial water saturation distribution

Source: created by the authors

The simulation was run for 10 years; for comparison, the baseline scenario (red line) was first considered without taking into account additional pressure losses during reservoir fluid filtration at the Darcy's law limit (Fig. 7).

In this case, the initial flow rate of the well was 1 million m^3/day, but within 2-3 months it decreased and stabilised at around 70 thousand m^3/day. This is due to the relatively small stimulated volume and the rapid progression of the pressure drop to the limits of this volume. W1 almost immediately switches to 180 bar bottom-hole pressure control, as its productivity and drainage volume do not allow it to maintain a plateau for longer than 2-3 months with this fracture configuration. Projected accumulated gas production over 10 years amounted to 101 million m^3, which corresponds to approximately 3% of the original gas volume. The resulting profiles of production, reservoir pressure drop and gas condensate factor (GCF) are shown in Figure 8.

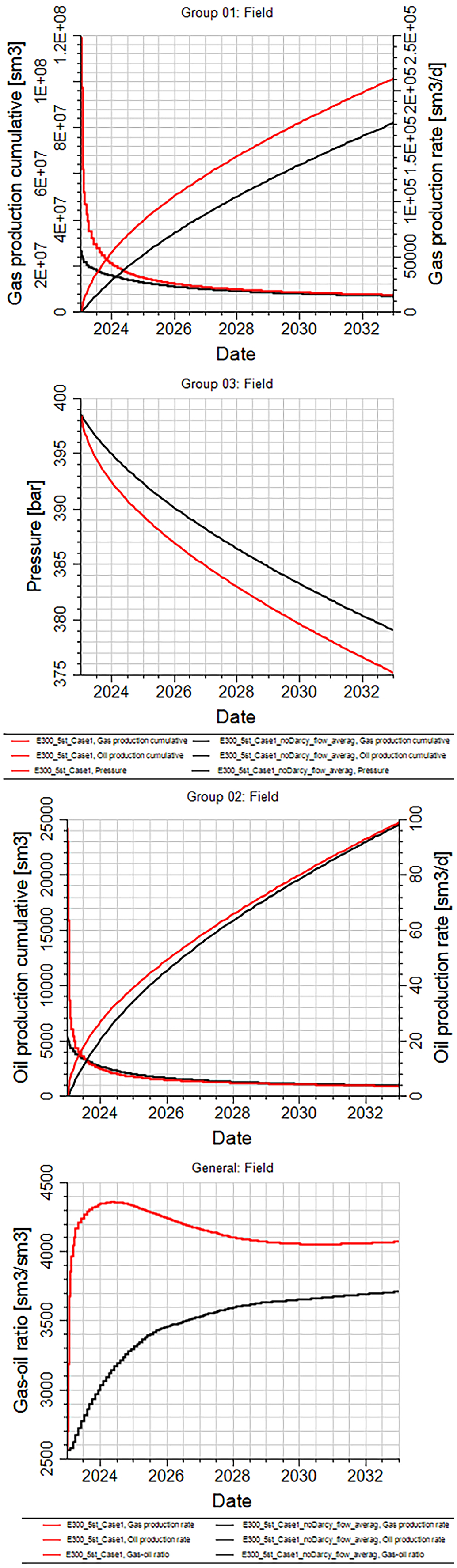

Figure 7. Comparison of the baseline and alternative scenario

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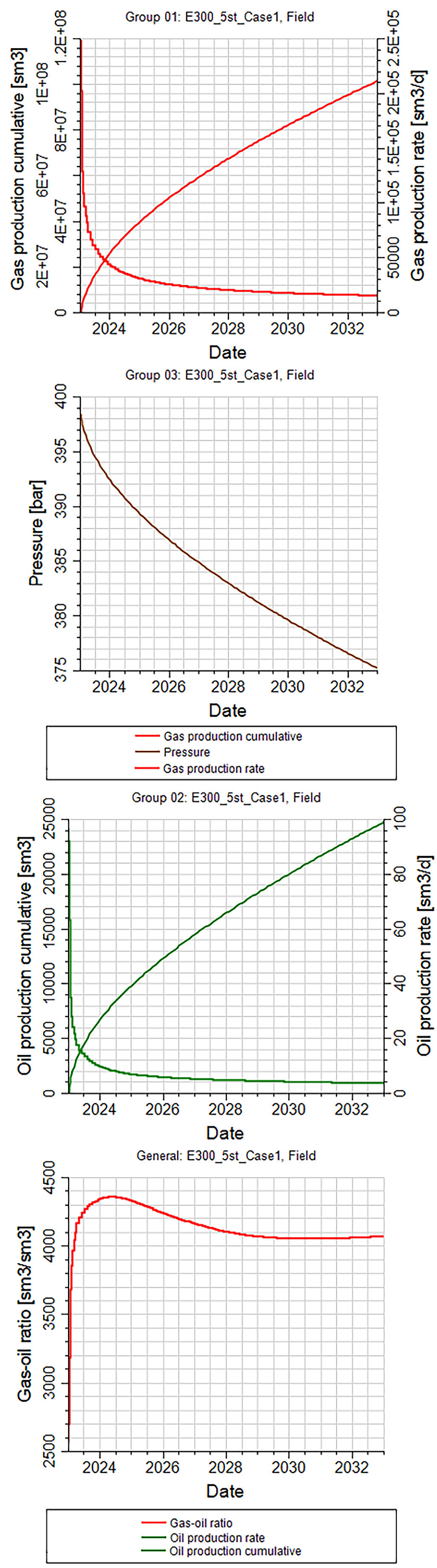

Figure 8. Production, pressure and GCF profiles for the baseline scenario

Source: created by the authors

As a rule, additional pressure losses due to filtration at the limit of Darcy's law (D-factor) are determined after processing well tests at different operating conditions using the method of A. Houpeurt (1959). However, these tests are rare for horizontal wells developing low-permeability manifolds. Therefore, due to the lack of data, typical correlations that are functions of the main reservoir filtration and capacitance properties, such as porosity, permeability, capacity or complexity of the pore channel system, have been widely used. Equations for determining β, containing τ – tortuosity of the pore channel system, which is not widely used due to the complexity of correctly determining this parameter. It should be noted that the correlations presented in this paper, some of which were used to determine the D-factor for the synthetic hydrodynamic model, showed a large discrepancy in the results. In the absence of well testing results in different operating modes, it is necessary to select a correlation from the literature, taking into account the lithology and average filtration and capacitance parameters. In the work of H. Saboorian-Jooybari & P. Pourafshary (2015), the limits of application of each correlation are given. For example, dependencies (14) and (15) are used for microscopic models in the explicit modelling of a pore channel system, which is not relevant to this study. Correlation (5) is generally applied when the presence of CO_2 or N_2 exceeds 5% in the formation fluid.

In order to account for the D-factor calculated in Table 3, an additional value was set in the simulation model in accordance with the Eclipse hydrodynamic simulator manual, using the required syntax in the simulation model. An alternative simulation was calculated using the average D-factor value from Table 3. According to the results of the alternative scenario (black line in Fig. 8), taking into account the average D-factor from Table 3, the initial gas flow rate of the W1 decreased from 1 million m^3/day up to 60 thousand m^3, at the same time, you can see that over time, the difference between the baseline and alternative scenarios decreases and almost disappears. This is due to a decrease in extraction and reservoir pressures. The greatest impact, as expected, is observed at high gas flow rates. The resulting accumulated gas production decreased from 101 million m^3 up to 83 million m^3, which is 17.8% less than the baseline scenario.

The addition of the pessimistic D-factor value from Table 3 (5.1 E-02, blue line in Fig. 9) and the optimistic value (1.6 E-04, green line in Fig. 9) and the subsequent sensitivity analysis result in a difference of 35 million m^3 in accumulated gas production, with the resulting curves of accumulated selections shown in Figure 9. This, in turn, will have a huge impact on economic indicators when designing a horizontal well in this field, for the purpose of its development. It should be noted that non-traditional collectors are usually developed by a large number of horizontal wells with hydraulic fracturing, so the influence of the D-factor can have an accumulated effect and an incorrect assessment of it can cancel the implementation of the project as a whole.

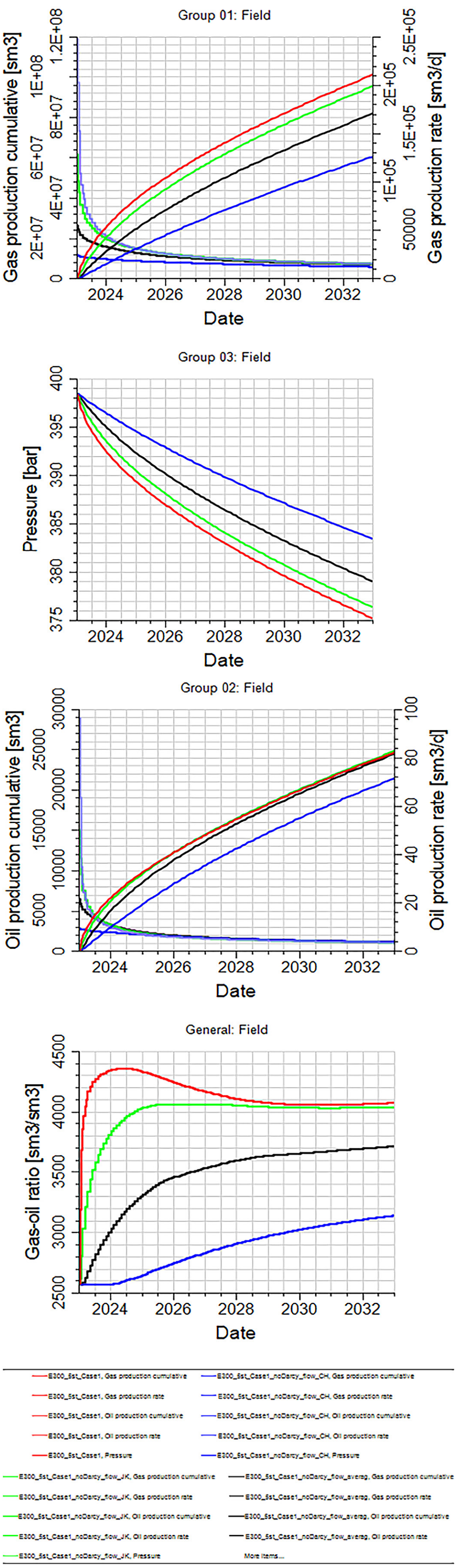

Figure 9. D-factor sensitivity analysis
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Accumulated gas withdrawals range between 60.7 million m³ (a decrease of almost 40% from the baseline scenario) and 95.7 million m³ (a 5% reduction from the baseline scenario). The results of a scenario with an average value of the D-factor are accepted as probable (P50), in order to correctly determine the optimistic (P10) and pessimistic (P90) scenarios and the range between them, which should correspond to the physical limits of the application of the D-factor, it is necessary to conduct a separate sensitivity analysis and determine the minimum and maximum values at which the change in the accumulated selections will not be noticeable. There is also an effect on the resulting stimulated volume and a significant difference between the baseline and alternative scenarios. Figure 10 and Figure 11 show the pressure distribution at the end of the forecast period of the baseline and alternative scenarios, respectively. The colour scheme clearly indicates a decrease in the area of the drained volume and a lower degree of reservoir depletion.

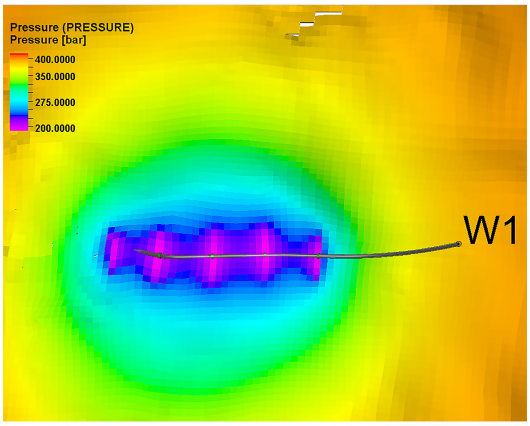

Figure 10. Pressure distribution at the end of the forecast period for the baseline scenario
Source: created by the authors

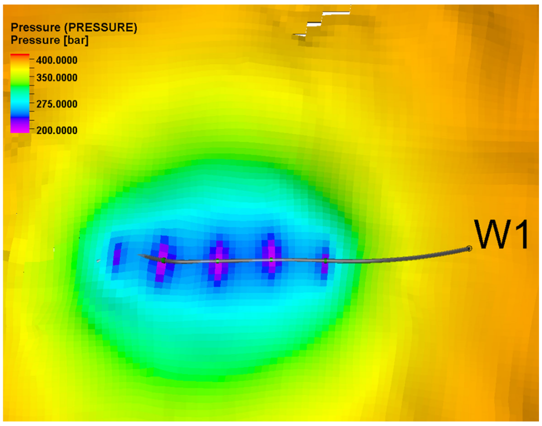

Figure 11. Pressure distribution at the end of the forecast period for the alternative scenario
Source: created by the authors

The obtained average value of the D-factor – 0.01 does not contradict the values obtained during other studies. For example, in the work of M.P. Ekeregbe (2023) the D-factor was determined by interpreting pressure recovery curves and typical curves. Values ranging from 0.013 to 0.04 were obtained, which were determined for different wells with different filtration and capacitive properties. Additional resistance coefficients were determined in this paper, compared with skin factors, and a number of flow rate dependencies were constructed. The author came to the conclusion that with an increase in the flow rate, the value of the D-factor and, in turn, the skin factor increased. The D-factor values for these dependencies varied from 0.04 to 0.07. The results of this study were supplemented with the proposed graphical method for integrating the dependence of the D-factor on the flow rate and skin factor, in order to determine the degree of fluid accumulation at the bottom of wells. The author distinguished into two separate categories the skin formed by the accumulation of fluid on the bottom-hole and the skin that depends on the speed of the upward flow. This methodology is interesting for approbation and further testing based on the results obtained in this study.

In addition to the parameters considered in this study, the work of H. Mustapha *et al*. (2015), added another, namely the effect of capillary pressure on deviation from filtration according to Darcy's law. According to their observations, capillary pressure mainly influenced the mobility of gas and water around fractures and significantly affected well productivity (up to 30%). However, in the case of the study presented in this article, the design of horizontal gas wells in low-permeability reservoirs is carried out with the maximum distance from the GCF, which minimises the appearance of water in the well production and ensures a single-phase (gas) or two-phase (gas + condensate) flow. In this case, the effect of capillary pressure on the phase distribution boundaries is minimal. However, the author noted that the influence of capillary forces can also have an impact on the level of matrix-fracture interaction, which is relevant for fractured reservoirs. The author emphasises the importance of a correct description of capillary forces using the example of the influence of the D-factor not only at the level of fractures but also in neighbouring cells. The degree of deviation from Darcy's law during filtration in fractures at different capillary pressures was also compared, and was up to 12%. However, the author noted that the uncertainties associated with the effect of capillary pressure are much larger than those associated with filtration at the Darcy's law limit and require additional analysis.

Research by S. Alakbarov & A. Behr (2020) showed a significant impact of the filtration effect on the boundaries of Darcy's law on a synthetic hydrodynamic model. However, during the simulation, the values of gas flow rates were around 750 thousand m³/day, while in this study the maximum flow rates reached only 250 thousand m³/day, and the effect of the additional coefficient of resistance was determined by the period during which the working bottom-hole pressure of the well reached the minimum values of 50 bar (for two or more years), while in this study this occurred almost from the very beginning of the simulation, due to the significantly lower permeability between hydrodynamic models. Also in the article, S. Alakbarov & A. Behr (2020) took into account the effect of the resulting condensate shaft, when the pressure drops below the dew point pressure, when part of the pore space is occupied by condensate, and the resulting values of the gas filtration rate are lower, due to the concept of relative phase permeability.

It should be noted that this effect is also found in oil deposits with a high gas content, as demonstrated in the work by D. Li *et al*. (2020), where the D-factor was also used as one of the parameters for tuning the hydrodynamic model to historical measurements of the operating bottom-hole pressure. In other words, this parameter can be used not only to estimate the performance parameters of forecast wells, but also to adapt the operating bottom-hole pressure. In this case, the sensitivity analysis of the model to various parameters, including the D-factor, is used, the possible range of change of each parameter is determined, and the possible combined impact is estimated. A similar effect of high values of the upward flow rate can be observed in fractured reservoirs, when the matrix is characterised by minimal permeability and natural fractures satisfy high well productivity. Studies by L. Wang & W. Yu (2019) showed that even with successive injection and extraction of gas at high rates of both upstream and downstream flows, the filtration effect at the limit of Darcy's law significantly affects both well acceptability and productivity, and at some point, the dependence becomes non-linear. In such a situation, it is necessary to have a data set to calibrate the additional pressure losses arising from the fluid flow rate in the hydrodynamic model. In all of the above studies, the D-factor is one of the key parameters that affects productivity, but due to its uncertainty, it is often ignored by reservoir engineers when predicting key well performance indicators.

From the above, it is clear that ignoring the effect of reservoir fluid filtration outside the Darcy's law for both conventional and unconventional reservoirs will lead to an overestimation of production rates and accumulated production. The results presented in this paper and those of other authors once again emphasise the criticality of taking into account the additional resistance factor when predicting and drilling horizontal wells in low permeability reservoirs. However, this analysis should be accompanied by a set of additional parameters that will affect the resulting cumulative production as indicated by the authors and publications cited above. This should include such parameters as reservoir filtration and capacitance parameters, their change and heterogeneity (lateral and vertical), PVT (pressure, volume, temperature) fluid properties and condensation factor, capillary pressure, and projected well production rates.

Conclusions

Summarising the research topic, it was possible to focus on the feasibility of including such a parameter as the D-factor in the analysis when predicting the production profiles of horizontal wells developing low-permeable deposits after hydraulic fracturing. Analysing the results obtained, it is clear that ignoring additional pressure losses during reservoir fluid filtration at the limit of Darcy's law may lead to the need to reassess the forecast indicators of field development and the productivity of some wells characterised by high upstream rates. As can be seen from the sensitivity analysis on the example of W1, the revaluation can reach 40%, which is significant when calculating the economic indicators of the feasibility of drilling an expensive horizontal well or conducting a multi-stage hydraulic fracturing.

As expected, the greatest impact was observed at high gas flow rate values, i.e. with an increase in gas flow rate, the influence of the D-factor increases and vice versa, at minimum flow rate values, the influence of the D-factor is also minimal. As a result of sensitivity analysis, there is a decrease in accumulated gas production from 101 million m^3 to 83 million m^3, which is almost 18% less than the baseline scenario. For other scenarios, accumulated gas production ranged from 60.7 million m^3 (a decrease of almost 40% from the baseline scenario) and 95.7 million m^3 (5% decrease from the baseline scenario). However, the choice of correlation dependencies for calculating the D-factor should be reasonably approached and sensitivity analysis should be applied to cover the uncertainty field and generate scenarios such as P10 (optimistic), P50 (probable) and P90(pessimistic).

This work is planned to expand and investigate the influence of such parameters as PVT properties of fluids, namely condensate factor and retrograde processes occurring at the fracture level. Determine the component composition of condensate that falls out in the bottom-hole zone and blocks part of the pore space. The combined effect of D-factor and condensate shaft formation after multi-stage hydraulic fracturing is one of the further areas of this study that should be considered. It is also planned to implement the use of the D-factor in predicting the main development indicators on the example of a real DDB field and supplement this study. All these points are areas of further research.

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None.

Conflict of Interest

None.

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Визначення D-фактору та його вплив на стимульований об'єм ущільнених газонасичених колекторів

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Анотація. Коректна оцінка можливого об'єму заміщення фонду структур традиційних колекторів ущільненими пісковиками / карбонатами діючих родовищ і районів видобувної діяльності є дискусійним питанням не лише в Україні, а й за кордоном, що викликано параметричною невизначеністю та впливом особливостей фільтрації пластових флюїдів у нетрадиційних колекторах. Це призводить до завищення прогнозних показників розробки ущільнених газонасичених колекторів, зменшення коефіцієнту заміщення та збільшення темпів падіння видобутку. Тому метою дослідження була оцінка впливу коефіцієнта додаткового опору фільтрації, що виникає у зв'язку з великою швидкістю висхідного потоку флюїду як одного з ключових невизначених параметрів, на продуктивність свердловин та результуючі накопичені відбори газу. Проведено багатостадійний гідророзрив пласта в синтетичній горизонтальній свердловині, що була створена в програмному забезпеченні Petrel. За допомогою типових кореляцій визначено коефіцієнти додаткового опору (D-фактору) та побудовано гідродинамічну модель у програмному забезпеченні Eclipse. Проведено симуляції з різним значенням D-фактору для визначення його впливу на продуктивність на накопичені відбори для одного типу породи. Результати дослідження свідчать, що переоцінка може сягати 40 %, що є суттєвим під час підрахунку економічних показників доцільності буріння та проведення багатостадійного гідророзриву пласта. Запропонована вибірка та методологія для низькопроникних пластів, що зустрічаються на родовищах Дніпровсько-Донецької западини України, може бути використана газо- та нафтовидобувними компаніями для деталізованого аналізу невизначеностей та коректного планування стабілізації темпів падіння видобутку газу

Ключові слова: коефіцієнт додаткового опору; фільтрація флюїдів; багатостадійний гідророзрив пласта; симуляція; дебіт свердловини