ISSN 2712-8008
Volume / Том 24 №1 2024
Journal Homepage: http://vestnik.pstu.ru/geo/

Perm Journal of Petroleum and Mining Engineering

UDC 622.276
Article / Статья
© PNRPU / ПНИПУ, 2024

Analysis and Reduction of Permeability Parameter Uncertainty in Carbonate Reservoir Modeling

Nikita D. Kozyrev, Sergey N. Krivoschekov, Alexander A. Kochnev, Evgeny S. Ozhgibesov, Polina O. Chalova, Andrey N. Botalov

Perm National Research Polytechnic University (29 Komsomolskiy av., Perm, 614990, Russian Federation)

Анализ и снижение неопределенности параметра проницаемости при моделировании карбонатного резервуара

Н.Д. Козырев, С.Н. Кривощеков, А.А. Кочнев, Е.С. Ожгибесов, П.О. Чалова, А.Н. Боталов

Пермский национальный исследовательский политехнический университет
(Российская Федерация, 614990, г. Пермь, Комсомольский проспект, д. 29)

Received / Получена: 18.09.2023. Accepted / Принята: 29.02.2024. Published / Опубликована: 31.03.2024

Keywords:
absolute permeability, complex carbonate reservoir, variability of absolute permeability, carbonate reservoir typification, geological and hydrodynamic modeling, petrophysical dependence.

The problem of variability of the absolute permeability of a carbonate complex reservoir in the vertical and lateral directions was analyzed. As part of the work, a detailed analysis of all available core material of the studied carbonate object was carried out. Based on the results of full-size core studies, it was established that the absolute permeability variability depends on the carbonate rock type, which could be complicated by secondary changes, such as the presence of fracturing and vugginess. The methodological approach described in this work made it possible to typify a complex carbonate reservoir, identifying several types of dense, low-porosity, porous, cavernous-porous, and fractured rocks. It was revealed that each type of carbonate reservoir had a certain correlation with the permeability parameter and its variability in different directions of the formation. It was established that the proportion of carbonate reservoir types differed significantly from well to well, therefore, this fact affected filtration processes, the degree and uniformity of production, as well as the rate of well watering. The next stage of the work took into account the variability of the permeability parameter in the current geological-hydrodynamic model of the studied object by creating cubes of absolute permeability in the Y and Z directions through a system of multipliers according to the identified correlation dependencies. The effectiveness of the presented method for typing and accounting for permeability variability was assessed by comparing modeling results with actual field data. In total, two options for implementing the geological-hydrodynamic model of a productive carbonate reservoir were considered. The first version of the model implied a standard method of creation, the second option corresponded to the developed methodological approach. When compared, it was revealed that the geological and hydrodynamic model, created taking into account typification and the corresponding variability, reproduced actual production with higher accuracy.

Ключевые слова:
абсолютная проницаемость, сложнопостроенный карбонатный коллектор, изменчивость абсолютной проницаемости, типизация карбонатного коллектора, геолого-гидродинамическое моделирование, петрофизическая зависимость.

Анализируется проблема изменчивости абсолютной проницаемости карбонатного сложнопостроенного коллектора в вертикальном и латеральном направлениях. В рамках работы проведен детальный анализ всего имеющегося кернового материала изучаемого карбонатного объекта. По результатам исследований полноразмерных образцов керна установлено, что изменчивость абсолютной проницаемости зависит от типа карбонатной породы, которая может быть осложнена вторичными изменениями, такими как наличие трещиноватости и кавернозности. Описанный в данной работе методический подход позволил произвести типизацию сложнопостроенного карбонатного коллектора, выделяя несколько типов плотных, низкопористых, пористых, кавернозно-пористых, трещиноватых пород. Выявлено, что каждый тип карбонатного коллектора имеет определенную корреляцию с параметром проницаемости и ее изменчивости в различных направлениях пласта. Установлено, что доля типов карбонатного коллектора значительно отличается от скважины к скважине, следовательно, данный факт оказывает влияние на фильтрационные процессы, на степень и равномерность выработки, а также на темпы обводнения скважин. Следующим этапом работы осуществлен учет изменчивости параметра проницаемости в действующей геолого-гидродинамической модели изучаемого объекта путем создания кубов абсолютной проницаемости в направлениях *Y* и *Z* через систему множителей согласно выявленным корреляционным зависимостям. Оценка эффективности представленного метода типизации и учета изменчивости проницаемости осуществлена путем сопоставления результатов моделирования с фактическими промысловыми данными. Всего рассмотрено два варианта реализации геолого-гидродинамической модели продуктивного карбонатного пласта. Первый вариант модели подразумевает стандартный способ создания, второй вариант соответствует разработанному методическому подходу. При сопоставлении выявлено, что геолого-гидродинамическая модель, созданная с учетом типизации и соответствующей ей изменчивости, с более высокой точностью воспроизводит фактическую добычу.

© **Nikita D. Kozyrev** (Author ID in Scopus: 57219308925) – Junior Researcher at the Department of Oil and Gas Geology (tel.: +007 (342) 219 80 17, e-mail: nikitonkozyrev@gmail.com). The contact person for correspondence.
© **Sergey N. Krivoschekov** (Author ID in Scopus: 54410873700, ORCID: 0000-0002-9748-6291) – PhD in Engineering, Associate Professor at the Department of Oil and Gas Geology (tel.: +007 (342) 219 83 07, email: krivoshchekov@gmail.com).
© **Alexander A. Kochnev** (Author ID in Scopus: 55747336200) – PhD in Engineering, Associate Professor at the Department of Oil and Gas Geology (tel.: +007 (342) 219 80 17, e-mail: sashakoch93@gmail.com).
© **Evgeny S. Ozhgibesov** (Author ID in Scopus: 57486568400, ORCID: 0009-0004-8235-0836) – Senior Lecturer Department of Oil and Gas Geology (tel.: +007 (342) 219 80 17, e-mail: ozhgibesov2015@yandex.ru).
© **Polina O. Chalova** (Author ID in Scopus: 57223986143, ORCID: 0000-0002-4862-0116) – Senior Lecturer at the Department of Oil and Gas Geology (tel.: +007 (342) 219 80 17, e-mail: chalovapolina@yandex.ru).
© **Andrey N. Botalov** (Author ID in Scopus: 58173917100, ORCID: 0000-0003-4291-7362) – Junior Researcher at the Department of Oil and Gas Geology (tel.: +007 (342) 219 80 17, e-mail: botalov97@yandex.ru).

© **Козырев Никита Дмитриевич** – младший научный сотрудник кафедры «Геология нефти и газа» (тел.: +007 (342) 219 80 17, e-mail: nikitonkozyrev@gmail.com). Контактное лицо для переписки.
© **Кривощеков Сергей Николаевич** – канд. техн. наук, доцент кафедры «Геология нефти и газа» (тел.: +007 (342) 219 80 17, e-mail: krivoshchekov@gmail.com).
© **Кочнев Александр Александрович** – Канд. техн. наук, доцент (тел.: +007 (342) 219 80 17, e-mail: sashakoch93@gmail.com).
© **Ожгибесов Евгений Сергеевич** – ассистент кафедры «Геология нефти и газа» (тел.: +007 (342) 219 80 17, e-mail: ozhgibesov2015@yandex.ru).
© **Чалова Полона Олеговна** – ассистент кафедры «Геология нефти и газа» (тел.: +007 (342) 219 80 17, e-mail: chalovapolina@yandex.ru).
© **Боталов Андрей Николаевич** – младший научный сотрудник кафедры «Геология нефти и газа» (тел.: +007 (342) 219 80 17, e-mail: botalov97@yandex.ru).

Please cite this article in English as:
Kozyrev N.D., Krivoschekov S.N., Kochnev A.A., Ozhgibesov E.S., Chalova P.O., Botalov A.N. Analysis and Reduction of Permeability Parameter Uncertainty in Carbonate Reservoir Modeling. *Perm Journal of Petroleum and Mining Engineering*, 2024, vol.24, no.1, pp.18-26. DOI: 10.15593/2712-8008/2024.1.3

Просьба ссылаться на эту статью в русскоязычных источниках следующим образом:
Анализ и снижение неопределенности параметра проницаемости при моделировании карбонатного резервуара // Н.Д. Козырев, С.Н. Кривощеков, А.А. Кочнев, Е.С. Ожгибесов, П.О. Чалова, А.Н. Боталов // Недропользование. – 2024. – Т.24, №1. – С.18–26. DOI: 10.15593/2712-8008/2024.1.3

Introduction

Modern ways of designing oil and gas field development are based on geological and hydrodynamic modeling. The geological and hydrodynamic model is a tool which allows you to reproduce the processes of field development and forecast technological indicators [1].

In the process of constructing models of complex carbonate reservoirs there are appeared many uncertainties in the properties of the reservoir, and especially their distribution in the inter-well space, due to the change of deposition cycles, the development of secondary processes, high zonal heterogeneity and compartmentalization [2, 3]. Underestimation of the complexity of the geological structure of carbonate reservoirs can lead to irrational field development design, selection of geological and technical measures and production drilling [4–6]. Improving approaches to modeling complex carbonate reservoirs and reducing the uncertainty of their structure is an urgent task [7].

Heterogeneity and anisotropy of carbonate reservoir properties, in particular lateral and vertical permeability have a strong influence on the processes of their development [8, 9]. In the carbonate reservoirs modeling these rock features should be taken into account.

There are different approaches to modeling complex carbonate reservoirs. The basic approach is to create a dual environment model [10]. This method is quite common, but it requires a large amount of input data for its implementation: core surveys, geophysical well surveys, hydrodynamic well surveys, results of 3D seismic surveys. The reservoir needs to be studied evenly over its volume [11]. In the early stages of development this technique is ineffective due to the limited amount of data [12].

To analyze and take into account uncertainties in reservoir properties, multivariate modeling is used. It makes possible to estimate a wide range of the main reservoir parameters (porosity, permeability, out-of-contour influence, etc.) and to adjust the model to historical data in a more reasonable way. Based on the results various implementations of the model are built with different degrees of reliability assessment and multivariate forecasting is performed. The technique has proven itself well in estimating uncertainties, but it has its shortcomings. As a rule, the criteria of geological realism and parameter consistency are not selected; as a result a number of model implementations turn out to be physically unrealistic [13, 14].

It is also necessary to consider the influence of secondary processes on the transformation of the void space of the rock. In [15] it is noted that leaching had a positive effect on the formation of reservoir properties of carbonate rocks of the Vereian horizon (North-West of the Republic of Bashkortostan), and the negative impact includes: calcitization of voids, recrystallization, rounding and sulfation. The secondary transformations of carbonate reservoir rocks, which are of fundamental importance in the formation of their filtration and capacitive properties has been considered in the article [16]. A formalized scheme illustrating the regularities of stage transformations in carbonate reservoirs and their interrelation with physical and chemical processes is described. The influence of secondary processes in conjunction with changes in sedimentation conditions entails significant variability of properties laterally and vertically [17–19]. In modeling it is not often paid much attention to studying the variability of properties in different directions [20–22]. Part of the research focuses on the study of anisotropy of properties through the processing of the results of seismic studies [23–26]. Other studies describe the variability of properties, in particular, permeability, based on the results of hydrodynamic studies of wells [27–28]. In [29–32], methods for assessing the anisotropy of permeability based on well data and core analysis were proposed. Approaches to modeling anisotropy of properties have been proposed in [29, 33–35].

One of the main parameters that determine fluid filtration in a reservoir is permeability [36–39]. When modeling carbonate reservoirs, standard approaches to permeability prediction are not possible, since the “permeability–porosity” petrophysical functions are unstable and have a large dispersion [40–42]. There are different types of void space – cracks, caverns, pores and mixed types. Filtration in such rocks is determined mainly by fractures and caverns [43–46].

In this paper it is proposed an approach to reduce the uncertainty of the permeability parameter in the process of creating a geological and hydrodynamic model of a complex carbonate reservoir by taking into account its lateral and vertical variability.

Analysis of the results of the standard and full-size core examination

To study the variability of the permeability parameter in the lateral and vertical directions one of the most promising fields "Alpha" which is located in the Timan-Pechersk region (the name is conventional) was chosen. The deposit is characterized by a complex geological structure, the presence of several carbonate layers, which, in turn, are complicated by secondary transformations of the pore space and the presence of caverns and fractures. Core samples were taken at the field from 12 wells; 679 full-size and 3499 standard samples were studied. The petrophysical function of standard and full-size samples has a low correlation coefficient, and also there is a high absolute permeability with a fairly low porosity, which indirectly indicates the presence of single cracks and caverns in dense rocks, and, conversely, with a sufficiently high porosity, low permeability values comparable to the values of the sub reservoir are observed (Fig. 1).

In order to correctly assess the variability of absolute permeability in different directions it is necessary to classify the rocks according to the studied core. Differentiation into rock types will make it possible to detail the study of properties and create a refined geological and hydrodynamic model of the reservoir which includes several types of pore space, in contrast to a single averaged approach, which, in turn, will have a significant impact on the process of model setting and its predictive ability.

Carbonate Reservoir Typing

At the first stage of the work, to assess the type of pore space, graphs of the accumulated correlation [47, 48] between open porosity and absolute permeability for standard and full-length core samples which made it possible to determine the degree of parameters correlation over the entire range of porosity and then permeability. Typification was carried out for two cycles of reef building separately: D3fm1(el1) и D3fm1(el3) (Fig. 2, 3).

Based on the accumulated correlations, it is possible to judge the relationship between filtration and capacitance properties by the range of porosity values of core samples. The trends of falling, rising, or stabilizing the curves of accumulated correlations and their alternation on the chart made it possible to judge the change in the type of void space. Since full-size samples characterize the void space more correctly, the division into ranges of porosity values was carried out on full-size samples.

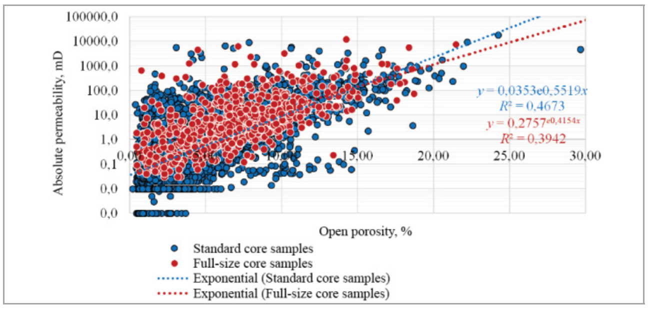


Fig. 1. Petrophysical functions of standard and full-size core samples

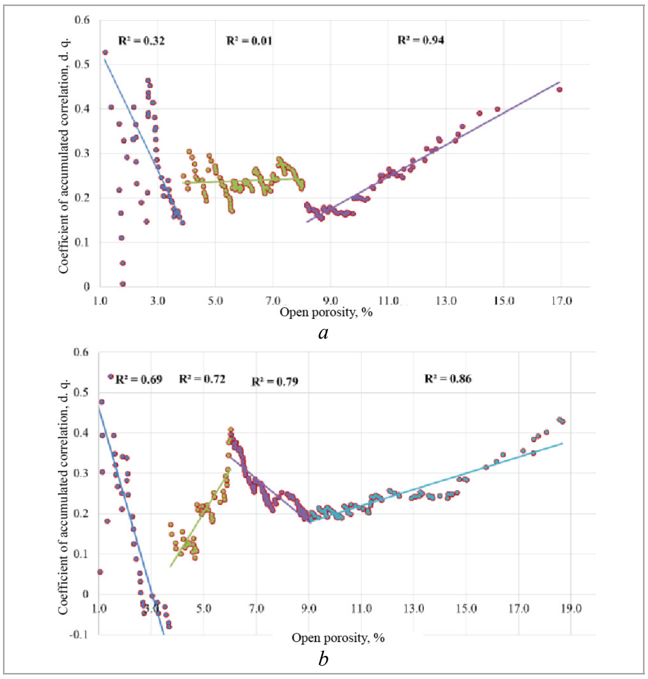


Fig. 2. Cumulative correlation plot between open porosity and absolute permeability for full-size core samples from open porosity values: *a* – D3fm1(el1); *б* – D3fm1(el3)

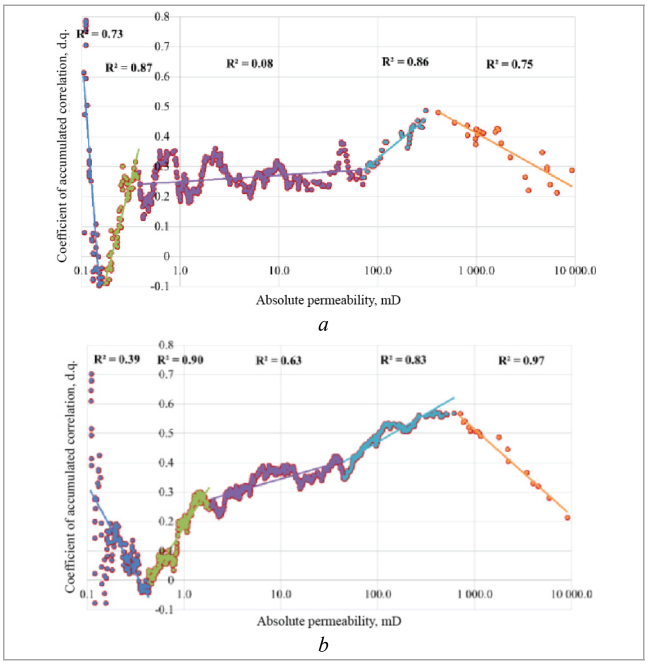


Fig. 3. Plot of the accumulated correlation between open porosity and absolute permeability for standard and full-size core samples as a function of absolute permeability: *a* – D3fm1(el1); *b* – D3fm1(el3)

For the reservoir D3fm1(el1) three ranges of porosity have been identified. The first range from a minimum value of up to 3.8 % characterizes the dense rock, low filtration characteristics correspond to the values of the sub-reservoir. The second porosity range from 3.8 to 8 % is characterized by stabilization of the accumulated correlation curve, i.e., as the open porosity increases, the absolute permeability cyclically rises and falls. Several types of rocks are found in this range of porosity: porous-matrix and rocks complicated by the presence of caverns and fractures. The third porosity range from 8% to maximum value is characterized by an increase in the accumulated correlation curve, that is, as the porosity increases, the permeability also increases monotonically. This fact indicates the pore type of the reservoir, which is practically uncomplicated by the presence of secondary transformations, that is, the absolute permeability is formed by the porous-matrix part of the reservoir.

For the reservoir D3fm1(el3) there are four ranges of porosity. The first range, from a minimum value of up to 3.8 %, is characterized by low matrix porosity and permeability, and these samples often do not have reservoir properties. The second range, from 3.8 to 6 %, is characterized by a significant increase in the accumulated correlation coefficient, which indicates the strengthening of the bond between porosity and permeability in this range, that is, as the porosity increases, the permeability also increases on average, the samples characterize to a greater extent the pore component of a complex reservoir. The third range, from 6 to 9 %, is characterized by a drop in the correlation coefficient as a result of a single inclusion of highly permeable caverns and cracks, but in the majority the samples have low permeability values. The fourth range of porosity, from 9 % to the maximum value, is characterized by a gradual increase in the coefficient of accumulated correlation: as the porosity increases, the permeability increases also. It should be noted that the permeability is formed by both porous and cavernous-fractured components.

Figure 3 shows the curves of accumulated correlations between the porosity and permeability of standard and full-size samples in the range of permeability values, which will also alllow the possibility to identify the ranges of various trends in the correlation of the porosity and permeability in terms of increasing permeability values.

For the reservoir D3fm1(el1) four ranges of absolute permeability have been identified. The first range, from the minimum value to 0.15 mD, is characterized as an impermeable sub-reservoir; the average porosity value for this permeability interval is 3.68 %. The second range, from 0.15 to 0.3 mD, is characterized by a significant increase in the accumulated correlation coefficient, which indicates a strengthening of absolute permeability and porosity bonds. The average porosity in this range is 4.77 %. This porosity range is mainly confined to a low-pore reservoir, but the presence of a strengthened bond between porosity and permeability suggests that this range is more related to a reservoir with low filtration and capacitance properties. Third permeability range from 0.3 to 70 mD is characterized by a slight increase in the accumulated correlation, and the cyclical nature of the coefficient decline and growth is also visible. This fact suggests that there are samples with high and low permeability values, that is, the reservoir is complicated by secondary transformations, such as cracks and caverns. The process of filtering according to this type of reservoir occurs both by the matrix component and by the secondary voids. The average porosity value in this permeability range is 6.2 %. The fourth range, from 70 to 320 mD, is characterized by a gradual increase in the coefficient of accumulated correlation practically without cyclicity. This type corresponds to high filtration and capacitive properties, to a greater extent, the filtration process should be carried out by the high-pore component. The average porosity value in this range is 11.0 %. The fifth permeability range, from 320 mD to the maximum value, is characterized by a drop in the accumulated correlation coefficient. The average porosity value is 11.8 %, which is slightly different from the fourth range, so it can be concluded that a reservoir with high porosity has secondary transformations such as cracks and caverns.

For the reservoir D3fm1(el3) there are five ranges of permeability. The first range, from minimum value of permeability to 0,3 mD, characterizes non-reservoir: average value of porosity in this range is not more than previously pointed value equal to 3,8 %. The second range, from 0.3 to 1.5 mD, is characterized by low permeability and matrix porosity; there is an increase in the correlation of values, the average porosity value is 4.9 %. In the third range, from 1.5 to 50 mD, there is a gradual strengthening of the relationship between filtration and capacitance characteristics, that is, the increase in permeability is due to an increase in porosity, the correlation coefficient increases from 0.3 to 0.4, and the average porosity value is 6.9 %. In the fourth range, from 50 to 700 mD, there is a higher growth rate of the correlation coefficient, pore-type samples with good reservoir properties (FES), and an average porosity value of 11.8 %. In the latter range, the correlation coefficient decreases, i.e. high permeability values are caused not only by high porosity, but also by the presence of secondary changes, such as caverns and fractures.

In the course of a comprehensive analysis of the accumulated correlations, a matrix of pseudo types of pore space was obtained first in the porosity ranges and then in the permeability ranges (Table 1).

When studying core material, a photographing procedure is carried out in daylight and ultraviolet light. Table 2 shows a visual comparison of the pseudo types of the carbonate reservoir with a photograph of the corresponding core.

Based on the results of statistical and visual analysis, we can see that for pseudo type 3 the permeability of 16.04 mD is caused not by the porosity value of 2.67 %, but by the presence of single caverns and microfractures. For pseudo type 10, the permeability of 6203.2 mD is also provided not by the porosity values of 7.1 %, but the presence of a high density of caverns and conductive cracks. A similar analysis was carried out for all identified pseudo types.

Determination of the coefficient of variability of absolute permeability in different directions

At the next stage of the work, the analysis of the coefficients of variability of absolute permeability was carried out. The coefficients of variability are calculated using the formulas (1), (2).

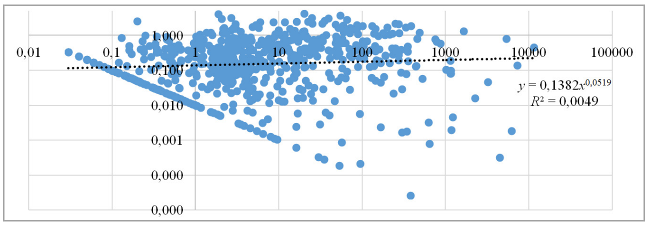


Fig. 4. The total dependence of the permeability variability coefficient in the Z direction from absolute permeability values

$$K_z = \frac{\text{perm}(z)}{\text{perm}(x)}, \quad (1)$$

where K_z – coefficient of variability in the vertical direction, perm(z) – value of absolute permeability in vertical direction, perm(x) – lateral permeability value X.

$$K_y = \frac{\text{perm}(y)}{\text{perm}(x)}, \quad (2)$$

where K_y – lateral variability coefficient, perm(y) – absolute permeability in the lateral direction Y, perm(x) – lateral permeability value X.

Fig. 4 shows a cloud of values of the coefficient of variability in the vertical direction from the values of permeability. To identify a stable dependence is impossible.

Thus, each selected pseudo type of pore space should have its own coefficient of permeability variability in the Y and Z directions.

At the next stage of the work, based on the results of studies of full-size core samples, the coefficient of permeability variability in various directions was calculated.

Table 3 shows the average coefficient of variability in the vertical and lateral directions for each pseudo type of pore space of the reservoir D3fm1(el1).

For the reservoir D3fm1(el1) it is noted that for low-pore rock the average coefficient of variability in the Z direction increases from the minimum porosity value to 3.8 % as the permeability increases; with permeability from 0.15 to 0.3 mD, the average coefficient is 0.640 decimal quantity, that is, the permeability increases in the X and Z directions, which indicates the absence of secondary transformations of the rock and fluid filtration only in the matrix component. Then, at higher permeability values, the coefficient decreases significantly, which indicates a permeability distribution only in the lateral direction, and in turn is caused by single highly conductive caverns. This fact also confirms the presence of a high coefficient of variability in the Y direction.

Table 1

A matrix of pseudo types of pore space for D3fm1(el1) and D3fm1(el3)

Connected porosity range, decimal quantity;	D3fm1(el1)				
	Absolute permeability range, mD				
	min–0,15	0,15–0,3	0,3–70	70–320	320–max
min – 3,8	1	2	3	4	5
3,8–8,0	6	7	8	9	10
8,0 – max	11	12	13	14	15
Connected porosity range, decimal quantity;	D3fm1(el3)				
	Absolute permeability range, mD				
	min–0,3	0,3–1,5	1,5–50	50–700	700–max
min – 3,8	16	17	18	19	20
3,8–6,0	21	22	23	24	25
6,0–9,0	26	27	28	29	30
9,0 – max	31	32	33	34	35

Table 2

Visual Comparison of Carbonate Reservoir Pseudotypes

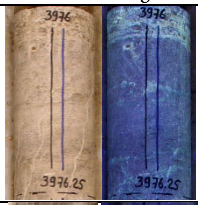
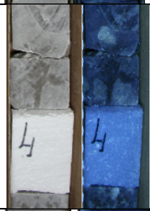
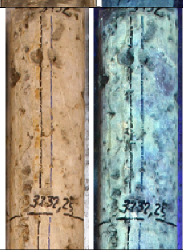
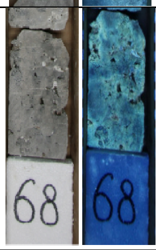
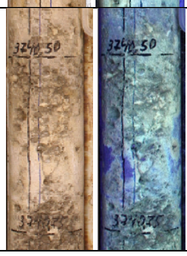
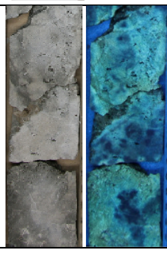
Reservoir	Type	Porosity value, %	Permeability value, mD	Photo of undamaged core	Photo of core drawdown
D3fm1(el1)	1	1,17	0,05		
D3fm1(el1)	2	2,42	0,17		
D3fm1(el1)	3	2,67	16,04		
D3fm1(el1)	6	5,3	0,14		
D3fm1(el1)	8	7,9	16,9		
D3fm1(el1)	10	7,1	6203,2		

Table 3

Values of the coefficient of variability in the vertical and lateral direction for the reservoir D3fm1(el1)

Connected porosity range, decimal quantity	D3fm1(el1). Coefficient of variability in direction *Z*, decimal quantity				
	Absolute permeability, mD				
	min – 0,15	0,15–0,3	0,3–70	70–320	320 – max
min – 3,8	0,151	0,640	0,206	–	0,002
3,8–8,0	0,071	0,232	0,303	0,429	0,042
8,0 – max	–	–	0,499	0,707	0,481
Connected porosity range, decimal quantity	D3fm1(el1). Coefficient of variability in direction *Y*, decimal quantity				
	Absolute permeability, mD				
	min – 0,15	0,15–0,3	0,3–70	70–320	320 – max
min – 3,8	0,632	0,635	0,541	–	0,733
3,8–8,0	0,571	0,728	0,648	0,696	0,001
8,0 – max	–	–	0,672	0,528	0,534

Table 4

Values of the coefficient of variability in the vertical and lateral direction for the reservoir D3fm1(el3)

Connected porosity range, decimal quantity	D3fm1(el3). Coefficient of variability in direction *Z*, decimal quantity.				
	Absolute permeability, mD				
	min – 0,3	0,3–1,5	1,5–50	50–700	700 – max
min – 3,8	0,148	0,144	0,643	0,266	–
3,8–6,0	0,375	0,278	0,327	0,144	0,005
6,0–9,0	0,384	0,482	0,432	0,448	0,016
9,0 – max	–	–	0,890	1,033	0,516
Connected porosity range, decimal quantity	D3fm1(el3). Coefficient of variability in direction *Y*, decimal quantity				
	Absolute permeability, mD				
	min –0,3	0,3–1,5	1,5–50	50–700	700 – max
min – 3,8	0,732	0,592	0,676	0,378	–
3,8–6,0	0,938	0,776	0,695	0,627	0,004
6,0–9,0	0,727	0,791	0,701	0,555	0,818
9,0 – max	–	–	0,760	0,746	0,751

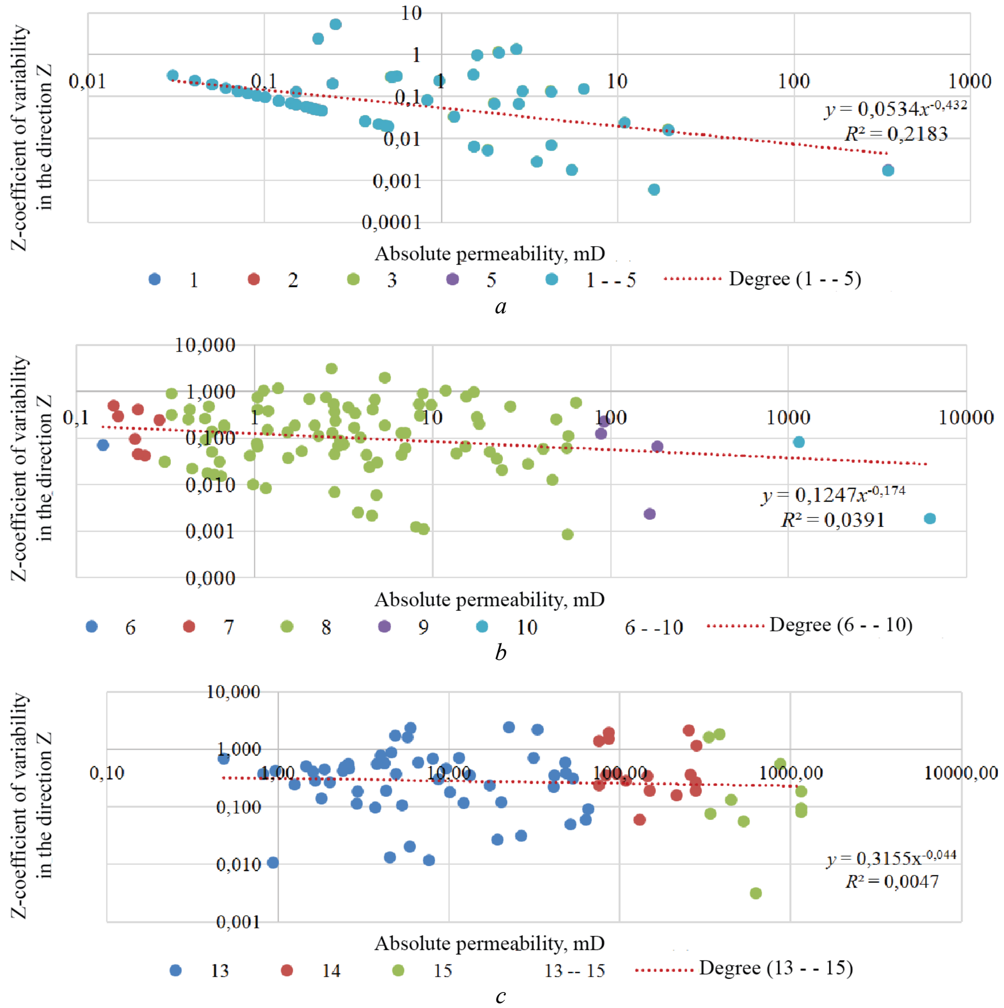


Fig. 5. Dependencies of the change in the coefficient of variability on the values of absolute permeability:
a – on minimal porosity value up to 3,8 %; *b* – porosity from 3,8 to 8,0 %; *c* – porosity from 8,0 % to maximum value

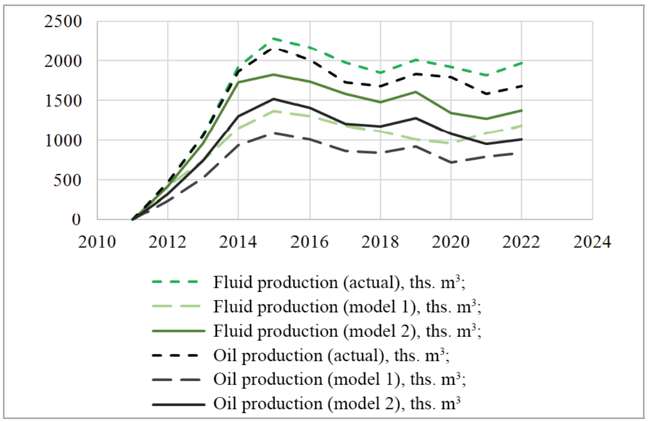


Fig. 6. Comparison of Estimated and Actual Oil and Liquid Production Levels for Model 1 and Model 2

Table 5

Comparison of the calculated and the actual accumulated oil and liquid production

Parameter	Value	Deviation,%
Accumulated fluid production (actual), ths. m^3	19 446,3	–
Accumulated fluid production (model 1), thousand m^3	11 522,2	40,7
Accumulated fluid production (model 2), ths. m^3	15 332,0	21,2
Accumulative oil production (actual), ths. m^3	17 868,7	–
Accumulative oil production (model 1), ths. m^3	8755,1	51,0
Accumulative oil production (model 2), ths. m^3	12 002,4	32,8

For more porous rock, from 3.8 to 8 %, there is a similar increase in the coefficient of variability up to 0.429 decimal quantity with permeability from 70 to 320 mD. Therefore, as permeability increases in the X direction, the permeability values increase in the Z direction, that is, as the permeability increases the pore component is involved to a greater extent. Further, a sharp decrease in the coefficient of variability to 0.042 decimal quantity is similarly observed; the permeability is formed by single caverns and fractures, which is confirmed by actual photographs of the core material. The coefficient of variability in the Y direction is also significantly reduced at maximum permeability values. More highly porous rocks, from 8% to maximum values, are characterized by a more uniform distribution of permeability in the X and Z directions, the rocks contain a large number of small caverns and fractures in all directions, which is confirmed by high values of the variability coefficient in the Y direction.

A similar analysis has been carried out for the reservoir D3fm1(el3). Table 4 shows the coefficients of variability in the vertical and lateral directions.

A more detailed analysis of the absolute permeability variability factor in the Z direction showed that there is no obvious relationship with the absolute permeability values. This is evidenced by the dependencies presented in Fig. 5. It was also found that over all ranges of porosity values, as permeability increases, there is a decrease in the coefficient of variability, if we consider typing only by porosity values.

It has been established that at lower values the dependence of porosity on the minimum values up to 3.8 %, a more stable dependence of the coefficient of permeability variability in the *Z* direction is observed. As porosity increases, the relationship between the coefficient of variability and permeability weakens significantly.

Since it was not possible to identify the dependence of the change in the coefficient of variability on the values of absolute permeability, it was decided to apply a system of multipliers of the average coefficient of variability of permeability for each previously identified rock pseudotype during geological-hydrodynamic modeling of the reservoir. A similar analysis was carried out for the coefficients of permeability variability in the Y direction.

Consideration of pseudotypes in the process of creating geological and hydrodynamic model of the studied reservoir

When creating a geological and hydrodynamic model of reservoir a single averaged coefficient of variability in the Z direction is often used, and if the formation is poorly studied, this coefficient is taken as 0.1, which is an incorrect modeling method. Also, in the standard modeling method, the absolute permeability in the *Y* direction corresponds to the values in the *X* direction.

In this paper, the coefficient of variability of absolute permeability is modeled using a system of multipliers for each pseudo type, which corresponds to the value of the coefficient of variability in the directions *Y* and *Z*.

The first stage was the differentiation into types according to the selected porosity ranges and absolute permeability over the entire permeability cube which was previously created from petrophysical functions for the reservoir D3fm1(el1) and D3fm1(el3) – (3), (4) correspondingly.

$$\mathrm{Perm}(x) = 0{,}135e^{0{,}5192\mathrm{poro}}, \quad (3)$$
$$\mathrm{Perm}(x) = 1{,}0134e^{0{,}2977\mathrm{poro}}, \quad (4)$$

where Perm(x) – absolute lateral permeability, mD, poro – connected porosity, %.

Further, for each cell of the permeability cube a different pseudo-type of rock is determined according to the values of porosity and absolute permeability. The next step was to calculate the permeability values in the *Y* and *Z* directions according to formulas (1) and (2). So, it has been determined three cubes of absolute permeability in the *X*, *Y*, *Z* directions.

At the next stage of the work the reproduction of field factual information was carried out for each well.

Figure 6 shows a comparison of actual and estimated oil and fluid production for two variants of models.

The first reservoir model was created in a standard way without taking into account the typification of rocks; the coefficients of variability in the vertical direction correspond to the average value for each of the productive layers. The second reservoir model is created taking into account the typification of rocks and the coefficient of variability in the lateral and vertical directions for each type. In order to correctly assess the effectiveness of the developed methodological approach no additional well-to-well adjustment of the model was carried out.

Table 5 shows a comparison of the estimated and actual accumulated oil and liquid production.

Based on the results of geological and hydrodynamic modeling, it was established that the model created with consideration the typification of rocks and the coefficient of variability in the lateral and vertical directions for each pseudo type showed a smaller percentage of deviation from the actual values of oil and liquid production relative to the model created in the standard way.

Conclusion

In this study in order to clarify and improve the prognostic ability of the geological and hydrodynamic model of a complex carbonate object a methodological approach has been developed. It makes it possible to differentiate all the studied core material into rock types using the curves of accumulated correlations. This method showed a good correlation when visually compared with core photographs and petrophysical description. The variability of absolute permeability values in the lateral and vertical directions has been studied. The analysis revealed that there is no stable correlation between the coefficient of variability and the permeability value itself. The average coefficient of variability for each identified pseudo type of rock was estimated. Two geological and hydrodynamic models of the studied reservoir were created: in a standard way and taking into account vertical and lateral variability of permeability. Additional consideration of pseudo types of rocks and further distribution of permeability variability coefficients in different directions made it possible to increase the detail of the model and its predictive ability, which will have a positive impact on the assessment of the technological and economic efficiency of geological and technological measures, the design of the reservoir maintenance system, the drilling of new wells and, in general, for the development project of the studied complex field.

References

1. Gareeva A.A. Znachenie geologo-gidrodinamicheskogo modelirovaniia pri razrabotke i ekspluatatsii neftianykh i gazovykh mestorozhdenii [The importance of geological and hydrodynamic modeling in the development and operation of oil and gas fields]. *Aktual'nye issledovaniia*, 2020, no. 22, pp. 68-70.
2. Arnold D., Demyanov V., Christie M., Bakay A., Gopa K. Optimisation of decision making under uncertainty throughout field lifetime: A fractured reservoir example, *Computers & Geosciences*, 2016, vol. 95, pp. 123-139. DOI: 10.1016/j.cageo.2016.07.011
3. Kozyrev N.D., Vishniakov A.Iu., Putilov I.S. Otsenka vliianiia parametrov neopredelennosti na prognozirovanie pokazatelei razrabotki [Assessment of the Uncertainty Parameters Influence on the Development Indicators Forecasting]. *Nedropol'zovanie*, 2020, vol. 20, no. 4, pp. 356-368. DOI: 10.15593/2712-8008/2020.4.5
4. Mogensen K., Masalmeh S. A review of EOR techniques for carbonate reservoirs in challenging geological settings. *Journal of Petroleum Science and Engineering*, 2020, vol. 195, 107889 p. DOI: 10.1016/j.petrol.2020.107889
5. Jian G. et al. Advances and challenges in CO_2 foam technologies for enhanced oil recovery in carbonate reservoirs. *Journal of Petroleum Science and Engineering*, 2021, vol. 202, 108447 p. DOI: 10.1016/j.petrol.2021.108447
6. Magalhães A.J.C. et al. High-resolution sequence stratigraphy applied to reservoir zonation and characterisation, and its impact on production performance-shallow marine, fluvial downstream and lacustrine carbonate settings. *Earth-Science Reviews*, 2020, vol. 210, 103325 p. DOI: 10.1016/j.earscirev.2020.103325
7. Mahdaviara M., Rostami A., Keivanimehr F., Shahbazi K. Accurate determination of permeability in carbonate reservoirs using Gaussian Process Regression. *Journal of Petroleum Science and Engineering*, 2021, vol. 196, 107807 p. DOI: 10.1016/j.petrol.2020.107807
8. Li R. et al. Quantitative evaluation of the carbonate reservoir heterogeneity based on production dynamic data: A case study from Cretaceous Mishrif formation in Halfaya oilfield, Iraq. *Journal of Petroleum Science and Engineering*, 2021, vol. 206, 109007 p. DOI: 10.1016/j.petrol.2021.109007
9. Tadayoni M., Khalilbeyg M., Bin Junin R. A new approach to heterogeneity analysis in a highly complex carbonate reservoir by using borehole image and conventional log data. *Journal of Petroleum Exploration and Production Technology*, 2020, vol. 10, pp. 2613-2629. DOI: 10.1007/s13202-020-00930-4
10. Zambrano M. et al. Pore-scale dual-porosity and dual-permeability modeling in an exposed multi-facies porous carbonate reservoir. *Marine and Petroleum Geology*, 2021, vol. 128, 105004 p. DOI: 10.1016/j.marpetgeo.2021.105004
11. Kargarpour M.A. Carbonate reservoir characterization: an integrated approach. *Journal of Petroleum Exploration and Production Technology*, 2020, vol. 10, no. 7, pp. 2655-2667.
12. Song H. et al. Analysis and Application of Fractured Carbonate Dual-Media Composite Reservoir Model. *Geofluids*, 2022, vol. 2022, 6785373 p. DOI: 10.1155/2022/6785373
13. Eremyan G., Demyanov V., Popova O., Kaygorodov S., Korovin M. Geology driven history matching. *In proceedings of the SPE Russian Petroleum Technology Conference*, January 2019. DOI:10.2118/196881-RU
14. Benetatos C., Giglio G. Coping with uncertainties through an automated workflow for 3D reservoir modelling of carbonate reservoirs. *Geoscience frontiers*, 2021, vol. 12, no. 6, 100913 p. DOI: 10.1016/j.gsf.2019.11.008
15. Riasnoi A.A., Savel'eva E.N. Vliianie vtorichnykh protsessov na kollektorskie svoistva karbonatnykh porod vereiskogo neftegazonosnogo kompleksa (Severo-Zapad Respubliki Bashkortostan) [Influence of secondary processes on reservoir properties of carbonate rocks in the Vereysky oil and gas field (North-West of the Republic of Bashkortostan)]. *Regional'naia geologiia i metallogeniia*, 2019, no. 77, pp. 27-39.
16. Tugarova M.A. Vtorichnye izmeneniia karbonatnykh porod neftegazonosnykh kompleksov [Secondary changes in carbonate rocks of oil and gas complexes]. *PROneft'. Professional'no o nefti*, 2020, no. 4 (18), pp. 18-23. DOI 10.7868/S2587739920040023
17. Abdulaziz A.M., Hawary S.S. Prediction of carbonate diagenesis from well logs using artificial neural network: An innovative technique to understand complex carbonate systems. *Ain Shams Engineering Journal*, 2020, vol. 11, no. 4, pp. 1387-1401. DOI: 10.1016/j.asej.2020.01.010
18. Mohammed-Sajed O.K., Glover W.J., Al-Khatony F.H., Collier R.E. Qualitative and quantitative diagenetic modelling in a tight carbonate reservoir in north-western Iraq. *Geoenergy Science and Engineering*, 2024, vol. 232, 212450 p. DOI: 10.1016/j.geoen.2023.212450
19. Armelenti G. et al. Depositional and diagenetic impacts on the porosity of post-salt carbonate reservoirs of southern Campos Basin, southeastern Brazilian margin. *Journal of South American Earth Sciences*, 2021, vol. 112, 103566 p. DOI: 10.1016/j.jsames.2021.103566
20. Martyushev D.A. Improving the geological and hydrodynamic model of a carbonate oil object by taking into account the permeability anisotropy parameter. *Journal of Mining Institute*, 2020, vol. 243, pp. 313-318.
21. Bouchaala F. et al. Azimuthal Investigation of a Fractured Carbonate Reservoir. *SPE Reservoir Evaluation & Engineering*, 2023, vol. 26, no. 03, pp. 813-826. DOI: 10.2118/212873-PA
22. Eltom H.A. et al. Three-dimensional modeling and fluid flow simulation for the quantitative description of permeability anisotropy in tidal flat carbonate. *Energies*, 2020, vol. 13, no. 21, 5557 p. DOI: 10.3390/en13215557
23. Ding Y. et al. A novel neural network for seismic anisotropy and fracture porosity measurements in carbonate reservoirs. *Arabian Journal for Science and Engineering*, 2021, pp. 1-23.
24. Guo X. et al. Seismic Anisotropic Fluid Identification in Fractured Carbonate Reservoirs. *Energies*, 2022, vol. 15, no. 19, 7184 p. DOI: 10.3390/en15197184
25. Aljawad M.S. Permeability anisotropy impact on wormhole propagation in openhole and limited-entry completions: A 3D numerical study. *Gas Science and Engineering*, 2023, 205050 p. DOI: 10.1016/j.jgsce.2023.205050
26. Krivoshchekov S., Kochnev A., Kozyrev N., Ozhgibesov E. Factoring Permeability Anisotropy in Complex Carbonate Reservoirs in Selecting an Optimum Field Development Strategy. *Energies*, 2022, vol. 15, no. 23, 8866 p. DOI: 10.3390/en15238866
27. Pandey V.K. et al. Vertical Interference Testing as a Gateway to Permeability Anisotropy Demystification and Understanding Fluid Displacement in Carbonates. *SPE Reservoir Characterisation and Simulation Conference and Exhibition*. SPE, 2023. DOI: 10.2118/212646-MS
28. Mengaliev A.G., Martiushev D.A. Uchet parametra anizotropii pronitsaemosti v geologo-gidrodinamicheskikh modeliakh karbonatnykh ob"ektov (na primere Gagarinskogo mestorozhdeniia) [Accounting the parameter of anisotropy of permeability in geological and hydrodynamic models of carbonate objects (on the example of the Gagarin deposit)]. *Izvestiia Tomskogo politekhnicheskogo universiteta. Inzhiniring georesursov*, 2020, vol. 331, no. 5, pp. 7-17. DOI: 10.18799/24131830/2020/5/2632
29. Marion D., Gonzalez H.J., Crawford P.B. Estimation of Reservoir Anisotropy From Production Data. *J. Pet. Technol.*, 1962, vol. 14, pp. 909-912. DOI: 10.2118/97-PA
30. Shedid H. Prediction of vertical permeability and reservoir anisotropy using coring data. *Journal of Petroleum Exploration and Production Technology*, 2019, vol. 9, pp. 2139-2143. DOI: 10.1007/s13202-019-0614-0
31. Farouk S. et al. Petrophysical assessment and permeability modeling utilizing core data and machine learning approaches-a study from the Badr El Din-1 field, Egypt. *Marine and Petroleum Geology*, 2021, vol. 133, 105265 p. DOI: 10.1016/j.marpetgeo.2021.105265
32. Al-Dujaili A.N., Shabani M., AL-Jawad M.S. Identification of the best correlations of permeability anisotropy for Mishrif reservoir in West Qurna/1 oil Field, Southern Iraq. *Egyptian Journal of Petroleum*, 2021, vol. 30, no. 3, pp. 27-33. DOI: 10.1016/j.ejpe.2021.06.001
33. Sinan S., Glover P.W.J., Lorinczi P. Modelling the Impact of Anisotropy on Hydrocarbon Production in Heterogeneous Reservoirs. *Transp. Porous. Med.*, 2020, vol. 133, pp. 413-436. DOI: 10.1007/s11242-020-01430-z
34. Sharifi J. et al. Investigation of static and dynamic bulk moduli in a carbonate field. *Exploration Geophysics*, 2021, vol. 52, no. 1, pp. 16-41. DOI: 10.1080/08123985.2020.1756693
35. Baiuk I.O., Dubinia N.V., Tikhotskii S.A. Problemy petrouprugogo modelirovaniia treshchinovatykh kollektorov [Some problems of Rock-Physics modeling of fractured carbonate reservoir rocks]. *PRONEFT''. Professional'no o nefti*, 2022, no. 3, pp. 11-17. DOI: 10.24887/2587-7399-2019-3-11-17
36. Sheldon H.A. et al. Realistic permeability distributions in faults and sediments: The key to predicting fluid flow in sedimentary basins. *Basin Research*, 2023, vol. 35, no. 6, pp. 2118-2139. DOI: 10.1111/bre.12792
37. Rasmussen A.F. et al. The open porous media flow reservoir simulator. *Computers & Mathematics with Applications*, 2021, vol. 81, pp. 159-185. DOI: 10.1016/j.camwa.2020.05.014
38. Islam M.R. et al. Advanced petroleum reservoir simulation: Towards developing reservoir emulators. John Wiley & Sons, 2016. DOI: 10.1002/9781119038573
39. Lucia F.J., Kerans C., Jennings J.W. Jr. Carbonate reservoir characterization. *Journal of Petroleum Technology*, 2003, vol. 55, no. 06, pp. 70-72. DOI: 10.1007/978-3-540-72742-2
40. Martin A.J., Solomon S.T., Hartmann D.J. Characterization of petrophysical flow units in carbonate reservoirs. *AAPG bulletin*, 1997, vol. 81, no. 5, pp. 734-759. DOI: 10.1306/522B482F-1727-11D7-8645000102C1865D
41. Yose L.A. et al. Three-dimensional characterization of a heterogeneous carbonate reservoir. *Lower Cretaceous, Abu Dhabi (United Arab Emirates)*, 2006. DOI: 10.1306/1215877M882562
42. Adegbite J.O., Belhaj H., Bera A. Investigations on the relationship among the porosity, permeability and pore throat size of transition zone samples in carbonate reservoirs using multiple regression analysis, artificial neural network and adaptive neuro-fuzzy interface system. *Petroleum Research*, 2021, vol. 6, no. 4, pp. 321-332. DOI: 10.1016/j.ptlrs.2021.05.005
43. Male F., Duncan I.J. Lessons for machine learning from the analysis of porosity-permeability transforms for carbonate reservoirs. *Journal of Petroleum Science and Engineering*, 2020, vol. 187, 106825 p. DOI: 10.1016/j.petrol.2019.106825
44. Salifou I.A.M. et al. New vuggy porosity models-based interpretation methodology for reliable pore system characterization, Ordovician carbonate reservoirs in Tahe Oilfield, North Tarim Basin. *Journal of Petroleum Science and Engineering*, 2021, vol. 196, 107700 p. DOI: 10.1016/j.petrol.2020.107700
45. Mohammadian E. et al. A case study of petrophysical rock typing and permeability prediction using machine learning in a heterogenous carbonate reservoir in Iran. *Scientific Reports*, 2022, vol. 12, no. 1, 4505 p. DOI: 10.1038/s41598-022-08575-5

46. Mulyanto B.S. et al. Porosity and permeability prediction using pore geometry structure method on tight carbonate reservoir. *Journal of Physics: Conference Series*. IOP Publishing, 2020, vol. 1572, no. 1, 012052 p. DOI: 10.1088/1742-6596/1572/1/012052
47. Repina V.A., Galkin V.I., Galkin S.V. Primenenie kompleksnogo ucheta petrofizicheskikh kharakteristik pri adaptatsii geologo-gidrodinamicheskikh modelei (na primere vizeiskoi zalezhi Gondyrevskogo mestorozhdeniia nefti) [Complex petrophysical correction in the adaptation of geological hydrodynamic models (on the example of Visean pool of Gondyrev oil field)]. *Zapiski Gornogo instituta*, 2018, vol. 231, pp. 268-274. DOI: 10.25515/PMI.2018.3.268
48. Galkin V.I., Ponomareva I.N., Repina V.A. Study of oil recovery from reservoirs of different void types with use of multidimensional statistical analysis. *Perm Journal of Petroleum and Mining Engineering*, 2016, no. 19, pp. 145-154. DOI: 10.15593/2224-9923/2016.19.5

Библиографический список

1. Гареева, А.А. Значение геолого-гидродинамического моделирования при разработке и эксплуатации нефтяных и газовых месторождений / А.А. Гареева // Актуальные исследования. – 2020. – №. 22. – С. 68–70.
2. Optimisation of decision making under uncertainty throughout field lifetime: A fractured reservoir example / D. Arnold, V. Demyanov, M. Christie, A. Bakay, K. Gopa // Computers & Geosciences. – 2016. – Vol. 95. – P. 123–139. DOI: 10.1016/j.cageo.2016.07.011
3. Козырев, Н.Д. Оценка влияния параметров неопределенности на прогнозирование показателей разработки / Н.Д. Козырев, А.Ю. Вишняков, И.С. Путилов // Недропользование. – 2020. – Т. 20, № 4. – С. 356–368. DOI: 10.15593/2712-8008/2020.4.5
4. Mogensen, K. A review of EOR techniques for carbonate reservoirs in challenging geological settings / K. Mogensen, S. Masalmeh // Journal of Petroleum Science and Engineering. – 2020. – Vol. 195. – P. 107889. DOI: 10.1016/j.petrol.2020.107889
5. Advances and challenges in CO_2 foam technologies for enhanced oil recovery in carbonate reservoirs / G. Jian [et al.] // Journal of Petroleum Science and Engineering. – 2021. – Vol. 202. – P. 108447. DOI: 10.1016/j.petrol.2021.108447
6. High-resolution sequence stratigraphy applied to reservoir zonation and characterisation, and its impact on production performance-shallow marine, fluvial downstream, and lacustrine carbonate settings / A.J.C. Magalhães [et al.] // Earth-Science Reviews. – 2020. – Vol. 210. – P. 103325. DOI: 10.1016/j.earscirev.2020.103325
7. Accurate determination of permeability in carbonate reservoirs using Gaussian Process Regression / M. Mahdaviara, A. Rostami, F. Keivanimehr, K. Shahbazi // Journal of Petroleum Science and Engineering. – 2021. – Vol. 196. – P. 107807. DOI: 10.1016/j.petrol.2020.107807
8. Quantitative evaluation of the carbonate reservoir heterogeneity based on production dynamic data: A case study from Cretaceous Mishrif formation in Halfaya oilfield, Iraq / R. Li [et al.] // Journal of Petroleum Science and Engineering. – 2021. – Vol. 206. – P. 109007. DOI: 10.1016/j.petrol.2021.109007
9. Tadayoni, M. A new approach to heterogeneity analysis in a highly complex carbonate reservoir by using borehole image and conventional log data / M. Tadayoni, M. Khalilbeyg, R. Bin Junin // Journal of Petroleum Exploration and Production Technology. – 2020. – Vol. 10. – P. 2613–2629. DOI: 10.1007/s13202-020-00930-4
10. Pore-scale dual-porosity and dual-permeability modeling in an exposed multi-facies porous carbonate reservoir / M. Zambrano [et al.] // Marine and Petroleum Geology. – 2021. – Vol. 128. – P. 105004. DOI: 10.1016/j.marpetgeo.2021.105004
11. Kargarpour, M.A. Carbonate reservoir characterization: an integrated approach / M.A. Kargarpour // Journal of Petroleum Exploration and Production Technology. – 2020. – Vol. 10, № 7. – P. 2655–2667.
12. Analysis and Application of Fractured Carbonate Dual-Media Composite Reservoir Model / H. Song [et al.] // Geofluids. – 2022. – Vol. 2022. – P. 6785373. DOI: 10.1155/2022/6785373
13. Geology driven history matching / G. Eremyan, V. Demyanov, O. Popova, S. Kaygorodov, M. Korovin // In proceedings of the SPE Russian Petroleum Technology Conference. – January 2019. DOI:10.2118/196881-RU
14. Benetatos, C. Coping with uncertainties through an automated workflow for 3D reservoir modelling of carbonate reservoirs / C. Benetatos, G. Giglio // Geoscience frontiers. – 2021. – Т. 12, № 6. – P. 100913. DOI: 10.1016/j.gsf.2019.11.008
15. Рясной, А.А. Влияние вторичных процессов на коллекторские свойства карбонатных пород верейского нефтегазоносного комплекса (Северо-Запад Республики Башкортостан) / А.А. Рясной, Е.Н. Савельева // Регион. геология и металлогения. – 2019. – № 77. – С. 27–39.
16. Тугарова, М.А. Вторичные изменения карбонатных пород нефтегазоносных комплексов / М.А. Тугарова // PROнефть. Профессионально о нефти. – 2020. – № 4(18). – С. 18–23. DOI 10.7868/S2587739920040023.
17. Abdulaziz, A.M. Prediction of carbonate diagenesis from well logs using artificial neural network: An innovative technique to understand complex carbonate systems / A.M. Abdulaziz, S.S. Hawary // Ain Shams Engineering Journal. – 2020. – Vol. 11, № 4. – P. 1387–1401. DOI: 10.1016/j.asej.2020.01.010
18. Qualitative and quantitative diagenetic modelling in a tight carbonate reservoir in north-western Iraq / O.K. Mohammed-Sajed, W.J. Glover, F.H. Al-Khatony, R.E. Collier // Geoenergy Science and Engineering. – 2024. – Vol. 232. – P. 212450. DOI: 10.1016/j.geoen.2023.212450
19. Depositional and diagenetic impacts on the porosity of post-salt carbonate reservoirs of southern Campos Basin, southeastern Brazilian margin / G. Armelenti [et al.] // Journal of South American Earth Sciences. – 2021. – Vol. 112. – P. 103566. DOI: 10.1016/j.jsames.2021.103566
20. Martyushev, D.A. Improving the geological and hydrodynamic model of a carbonate oil object by taking into account the permeability anisotropy parameter / D.A. Martyushev // Journal of Mining Institute. – 2020. – Vol. 243. – P. 313–318.
21. Azimuthal Investigation of a Fractured Carbonate Reservoir / F. Bouchaala [et al.] // SPE Reservoir Evaluation & Engineering. – 2023. – Vol. 26, № 03. – P. 813–826. DOI: 10.2118/212873-PA
22. Three-dimensional modeling and fluid flow simulation for the quantitative description of permeability anisotropy in tidal flat carbonate / H.A. Eltom [et al.] // Energies. – 2020. – Vol. 13, № 21. – P. 5557. DOI: 10.3390/en13215557
23. A novel neural network for seismic anisotropy and fracture porosity measurements in carbonate reservoirs / Y. Ding [et al.] // Arabian Journal for Science and Engineering. – 2021. – P. 1–23.
24. Seismic Anisotropic Fluid Identification in Fractured Carbonate Reservoirs / X. Guo [et al.] // Energies. – 2022. – Vol. 15, № 19. – P. 7184. DOI: 10.3390/en15197184
25. Aljawad, M.S. Permeability anisotropy impact on wormhole propagation in openhole and limited-entry completions: A 3D numerical study / M.S. Aljawad // Gas Science and Engineering. – 2023. – P. 205050. DOI: 10.1016/j.jgsce.2023.205050
26. Factoring Permeability Anisotropy in Complex Carbonate Reservoirs in Selecting an Optimum Field Development Strategy / S. Krivoshchekov, A. Kochnev, N. Kozyrev, E. Ozhgibesov // Energies. – 2022. – Vol. 15, № 23. – P. 8866 DOI: 10.3390/en15238866
27. Vertical Interference Testing as a Gateway to Permeability Anisotropy Demystification and Understanding Fluid Displacement in Carbonates / V.K. Pandey [et al.] // SPE Reservoir Characterisation and Simulation Conference and Exhibition. – SPE, 2023. DOI: 10.2118/212646-MS
28. Менгалиев, А.Г. Учет параметра анизотропии проницаемости в геолого-гидродинамических моделях карбонатных объектов (на примере Гагаринского месторождения) / А.Г. Менгалиев, Д.А. Мартюшев // Известия Томского политехнического университета. Инжиниринг георесурсов. – 2020. – Т. 331, № 5. – С. 7–17. DOI: 10.18799/24131830/2020/5/2632
29. Marion, D. Estimation of Reservoir Anisotropy From Production Data / D. Marion, H.J. Gonzalez, P.B. Crawford // J. Pet. Technol. – 1962. – Vol. 14. – P. 909–912. DOI: https://doi.org/10.2118/97-PA
30. Shedid, H. Prediction of vertical permeability and reservoir anisotropy using coring data / H. Shedid // Journal of Petroleum Exploration and Production Technology. – 2019. – Vol. 9. – P. 2139–2143. DOI: 10.1007/s13202-019-0614-0
31. Petrophysical assessment and permeability modeling utilizing core data and machine learning approaches–a study from the Badr El Din-1 field, Egypt / S. Farouk [et al.] // Marine and Petroleum Geology. – 2021. – Vol. 133. – P. 105265. DOI: 10.1016/j.marpetgeo.2021.105265
32. Al-Dujaili, A.N. Identification of the best correlations of permeability anisotropy for Mishrif reservoir in West Qurna/1 oil Field, Southern Iraq / A.N. Al-Dujaili, M. Shabani, M.S. AL-Jawad // Egyptian Journal of Petroleum. – 2021. – Vol. 30, № 3. – P. 27–33. DOI: 10.1016/j.ejpe.2021.06.001
33. Sinan, S. Modelling the Impact of Anisotropy on Hydrocarbon Production in Heterogeneous Reservoirs / S. Sinan, P.W.J. Glover, P. Lorinczi // Transp. Porous. Med. – 2020. Vol. 133. – P. 413–436. DOI: 10.1007/s11242-020-01430-z
34. Investigation of static and dynamic bulk moduli in a carbonate field / J. Sharifi [et al.] // Exploration Geophysics. – 2021. – Vol. 52, № 1. – P. 16-41. DOI: 10.1080/08123985.2020.1756693
35. Баюк, И.О. Проблемы петроупругого моделирования трещиноватых коллекторов / И.О. Баюк, Н.В. Дубиня, С.А. Тихоцкий // PROНЕФТЬ. Профессионально о нефти. – 2022. – №. 3. – С. 11–17. DOI: 10.24887/2587-7399-2019-3-11-17
36. Realistic permeability distributions in faults and sediments: The key to predicting fluid flow in sedimentary basins / H.A. Sheldon [et al.] // Basin Research. – 2023. – Vol. 35, № 6. – P. 2118–2139. DOI: 10.1111/bre.12792
37. The open porous media flow reservoir simulator / A.F. Rasmussen [et al.] // Computers & Mathematics with Applications. – 2021. – Vol. 81. – P. 159–185. DOI: 10.1016/j.camwa.2020.05.014
38. Advanced petroleum reservoir simulation: Towards developing reservoir emulators / M.R. Islam [et al.]. – John Wiley & Sons, 2016. DOI: 10.1002/9781119038573
39. Lucia, F.J. Carbonate reservoir characterization / F.J. Lucia, C. Kerans, J.W. Jennings Jr // Journal of Petroleum Technology. – 2003. – Vol. 55, № 06. – P. 70–72. DOI: 10.1007/978-3-540-72742-2
40. Martin, A.J. Characterization of petrophysical flow units in carbonate reservoirs / A.J. Martin, S.T. Solomon, D.J. Hartmann // AAPG bulletin. – 1997. – Vol. 81, № 5. – P. 734–759. DOI: 10.1306/522B482F-1727-11D7-8645000102C1865D
41. Three-dimensional characterization of a heterogeneous carbonate reservoir / L.A. Yose [et al.] // Lower Cretaceous, Abu Dhabi (United Arab Emirates). – 2006. DOI: 10.1306/1215877M882562
42. Adegbite, J.O. Investigations on the relationship among the porosity, permeability and pore throat size of transition zone samples in carbonate reservoirs using multiple regression analysis, artificial neural network and adaptive neuro-fuzzy interface system / J.O. Adegbite, H. Belhaj, A. Bera // Petroleum Research. – 2021. – Vol. 6, № 4. – P. 321–332. DOI: 10.1016/j.ptlrs.2021.05.005
43. Male, F. Lessons for machine learning from the analysis of porosity-permeability transforms for carbonate reservoirs / F. Male, I.J. Duncan // Journal of Petroleum Science and Engineering. – 2020. – Vol. 187. – P. 106825. DOI: 10.1016/j.petrol.2019.106825
44. New vuggy porosity models-based interpretation methodology for reliable pore system characterization, Ordovician carbonate reservoirs in Tahe Oilfield, North Tarim Basin / I.A.M. Salifou [et al.] // Journal of Petroleum Science and Engineering. – 2021. – Vol. 196. – P. 107700. DOI: 10.1016/j.petrol.2020.107700
45. A case study of petrophysical rock typing and permeability prediction using machine learning in a heterogenous carbonate reservoir in Iran / E. Mohammadian [et al.] // Scientific Reports. – 2022. – Vol. 12, № 1. – P. 4505. DOI: 10.1038/s41598-022-08575-5
46. Porosity and permeability prediction using pore geometry structure method on tight carbonate reservoir / B.S. Mulyanto [et al.] // Journal of Physics: Conference Series. – IOP Publishing, 2020. – Vol. 1572, № 1. – P. 012052. DOI: 10.1088/1742-6596/1572/1/012052
47. Репина, В.А. Применение комплексного учета петрофизических характеристик при адаптации геолого-гидродинамических моделей (на примере визейской залежи Гондыревского месторождения нефти) / В.А. Репина, В.И. Галкин, С.В. Галкин // Записки Горного института. – 2018. – Т. 231. – С. 268–274. DOI: 10.25515/PMI.2018.3.268
48. Galkin, V.I. Study of oil recovery from reservoirs of different void types with use of multidimensional statistical analysis / V.I. Galkin, I.N. Ponomareva, V.A. Repina // Perm Journal of Petroleum and Mining Engineering. – 2016. – № 19. – С. 145–154. DOI: 10.15593/2224-9923/2016.19.5

Financing. The study was carried out with the support of the Government of Perm Krai, grant No. S-26/627.
Conflict of Interest. The authors declare no conflict of interest.
The contribution of the authors is equal.