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Article / Статья

Development of a Methodological Approach to Identifying Petrophysical Types of Complicated Carbonate Rocks According to Laboratory Core Studies

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Разработка методического подхода к выделению петрофизических типов сложнопостроенных карбонатных пород по данным лабораторного изучения керна

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Petrophysical typification of rocks in productive hydrocarbon deposits is one of the main stages of building a petrophysical model of a reservoir. For carbonate reservoirs characterised by a heterogeneous complex structure of the void space, the problem of identifying petrotypes is very relevant. An extensive review of literature on existing methods of petrophysical typification shows that the most well-known and widely used of them are based on simple theoretical models of the void space structure of rocks, which does not allow a full description of complex carbonate deposits. Moreover, the petrotypes identified on the basis of these methods do not agree with the results of microdescription of thin sections. A new methodological approach to the identification of petrophysical types of complex carbonate rocks was proposed, based on the integration of the results of standard (determination of the absolute gas permeability and open porosity coefficients) and special (nuclear magnetic resonance studies) core studies and data obtained in the lithological description of thin sections. The developed approach takes into account the main petrophysical properties of rocks that characterise their reservoir potential, as well as the structural features of the void space and the influence of secondary transformations. The proposed methodological approach was used to identify petrophysical types in the section of the Asselian-Sakmarian deposits of the Yareyuskoye field: six petrotypes were identified and described in detail, combined into four zones (zone of healed fracturing development , zone of leaching development, zone of leaching and open fracturing development , zone of open fracturing development), for each of them individual dependences of the absolute gas permeability coefficient on the open porosity coefficient and dependences of the Leverett J-function on the water saturation coefficient were constructed. The information obtained will allow a differentiated approach to geological and hydrodynamic modeling of hydrocarbon reservoirs.

Ключевые слова:
петрофизический тип, карбонатные породы, пустотное пространство, вторичные преобразования, коэффициент проницаемости, коэффициент пористости, кумулятивная кривая, ядерный магнитный резонанс, исследования керна, выщелачивание, трещиноватость, шлиф, коэффициент детерминации, *J*-функция Леверетта, коэффициент водонасыщенности.

Петрофизическая типизация пород продуктивных отложений месторождений углеводородов является одним из основных этапов построения петрофизической модели залежи. Для карбонатных коллекторов, характеризующихся неоднородным сложным строением пустотного пространства, задача выделения петротипов является весьма актуальной. Обширный литературный обзор существующих методов петрофизической типизации показывает, что наиболее известные и широко применяемые из них основаны на простых теоретических моделях строения пустотного пространства пород, что не позволяет в полной мере описывать сложнопостроенные карбонатные отложения. Более того, выделенные на основе данных методов петротипы не согласуются с результатами микроописания шлифов. Предложен новый методический подход к выделению петрофизических типов сложнопостроенных карбонатных пород, основанный на комплексировании результатов стандартных (определение коэффициентов абсолютной газопроницаемости и открытой пористости) и специальных (исследования методом ядерного магнитного резонанса) исследований керна и данных, полученных при литологическом описании шлифов. Разработанный подход учитывает основные петрофизические свойства пород, характеризующие ее коллекторский потенциал, а также особенности строения пустотного пространства и влияния вторичных преобразований. Предложенный методический подход применен для выделения петрофизических типов в разрезе ассельско-сакмарских отложений одной из скважин Ярейюского месторождения: выделены и детально описаны шесть петротипов, объединенные в четыре зоны (зона развития залеченной трещиноватости, зона развития выщелачивания, зона развития выщелачивания и открытой трещиноватости, зона развития открытой трещиноватости), для каждого из них построены индивидуальные зависимости коэффициента абсолютной газопроницаемости от коэффициента открытой пористости и *J*-функции Леверетта от коэффициента водонасыщенности. Полученная информация позволит дифференцированно подходить к геологическому и гидродинамическому моделированию углеводородной залежи.

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Introduction

The identification of petrophysical types of rocks is an integral part of the construction of a petrophysical model that, in its turn, is the basis for a geological model of a hydrocarbon reservoir [1]. The fact that rocks with different petrophysical properties are present in the section is due to the complex heterogeneous structure of a productive formation, that results from the different conditions of sediment accumulation and the manifestation of secondary transformations [2]. This is especially characteristic of carbonate rocks and is due to a number of reasons. On the one hand, the facies conditions of sediment accumulation are very diverse even within the productive deposits of a specific hydrocarbon reservoir, which leads to the formation of a wide set of structural and textural features of rocks and therefore to dramatically different filtration-volumetric properties. On the other hand, the physicochemical properties of carbonate deposits make rocks extremely susceptible to the processes of secondary transformations (leaching, crack formation, stylolitisation, calcitisation, recrystallisation, authigenic mineral formation and many others) [3]. The effect of post-sedimentation transformations leads to a partial or complete change in the primary petrophysical properties of rocks formed at the stages of sedimentogenesis and early diagenesis. Moreover, the effects of secondary changes are not pervasive, but selective.

A review of literature on existing methods of petrophysical typification shows that the most well-known and widely used of them are based on simple theoretical models of the void space structure of rocks, and the petrophysical types identified on the basis of these methods do not agree with the results of microdescription of thin sections (the number of pores, their size, form, genesis, influence of secondary transformations on the void space, etc.).

This work suggests a new methodological approach to the identification of petrophysical types of complex carbonate rocks by integrating the results of laboratory core studies, which take into account the main physical properties of rocks that describe their reservoir potential, as well as the structural features of the void space (type of voids, form, genesis, quantity) and the influence of post-sedimentation transformations.

A Brief Review of Petrophysical Typification Methods

G.E. Archie was the first to define a petrophysical type [4] as the rock strata whose parts were deposited under the same conditions and underwent the same secondary transformation processes (destruction, cementation or dissolution). According to G.E. Archie, a specific petrotype has a certain pore size distribution and therefore an individual family of capillary pressure curves. The pore size distribution controls porosity and is associated with permeability and water saturation.

All methods of identifying petrophysical types of rocks can be conditionally divided according to their classified features into four groups: petrophysical, lithological, lithological-petrophysical and integrated.

Within the framework of petrophysical methods, the physical characteristics of rocks serve as the features that underlie the division of rocks into classes: the flow zone indicator (FZI) [5–18], the geometry and structure of the void space (PSG) [19, 20], the sizes of pore channels [21, 22], etc. These methods are characterised by a high degree of formalisation and therefore are popular among specialists.

In lithological petrotypification methods, the attributes underlying the division of rocks into classes are qualitative lithological characteristics of rocks, as well as genetic traits that have led to the formation of certain characteristics: the genesis of the void space, the influence of post-sedimentation processes, the presence and type of formed elements or granules, the structure of the cementing mass, etc. [23-26].

The identification of petrophysical types of rocks by lithological-petrophysical methods is based on the relationship between lithological (structural-textural) characteristics and petrophysical properties of carbonate rocks [27–29].

Integrated methods are separated as a special group due to the fact that within the framework of integrated approaches it is impossible to identify a predominant classification feature by which petrophysical types of rocks are identified. Petrotypes are identified and described using a large amount of data obtained from core studies, GIS, HDT, etc. [30–33].

Problem Setting and Characterisation of the Research Subject

The research subject is the core of the Asselian-Sakmarian deposits taken from the Yareyuskoye field. Data on 306 core samples were used for this work, of which 261 were of standard size and 45 were full-size samples. Standard studies were conducted for all the samples (determination of the open porosity coefficient and the absolute gas permeability coefficient), capillarimetric studies (in the gas-water system) and nuclear magnetic resonance (NMR) studies were conducted for 70 of them, and there is also a petrographic description of 72 thin sections taken from the places where the standard core samples were cut out.

In general, the deposits under study are represented by the layering of bioclastic, biohermal paleoplysine (paleoplysine-green-algal) limestones, microcodial, polyphytic-stromatoporic, bioclastic-polyphytic, unevenly oil-saturated limestones. Deposits are subject to various degrees of secondary transformation processes: calcitisation and recrystallisation, stylolitisation, silicification, dolomitisation, leaching.

As a result of the detailed analysis of data from the petrographic description of thin sections and the study of petrophysical properties, it has been established that the void space of the deposits under study is more determined by the influence of secondary (postdiagenetic) transformations than by the structural features of rocks formed at the stages of sedimentogenesis and early diagenesis.

The main filtration-volumetric properties of rocks that determine their reservoir potential are porosity and permeability. The relationship between these indicators is determined by the Kozeny–Carman equation [34, 35]:

$$K_{\text{пр}} = \frac{K_{\text{п}}^3}{f\, T_{\text{г}}^2 S_{\text{ф}}^2}, \qquad (1)$$

where $K_{\text{пр}}$ is the permeability coefficient, m^2; $K_{\text{п}}$ is the porosity coefficient, unit fractions; f is the coefficient depending on the form of the section of a pore channel; $T_{\text{г}}$ is the hydraulic tortuosity of pore channels, m/m; $S_{\text{ф}}$ is the specific surface area of pore channels, m^2/m^3.

Strictly speaking, this equation is theoretically derived for porous media with the correct geometric form of pore channels. As a rule, close connections between the permeability and porosity coefficients are observed for pore (granular) rocks that are usually terrigenous deposits. Alternatively, carbonate rocks have a complex structure of the pore space represented by voids of various sizes, forms and genesis. Figure 1 shows a comparison of the permeability and porosity coefficients of the core samples taken from the Yareyuskoye deposit. It can be observed that differences in permeability reach five orders of magnitude for the samples with the same open porosity value. A significant variance of data is not accidental, but is due to the presence of rocks with a different structure of the void space in the section under study and therefore belonging to different petrophysical types.

The determination coefficient (R^2) is very low (0.462), so the use of a generalised dependence to predict permeability may lead to serious errors in the construction of a geological-hydrodynamic model.

Development of a Methodological Approach to the Identification of Petrophysical Types

To fully describe the structure of the void space of such complex systems as rocks, especially carbonate deposits, the use of simple theoretical models and results of standard petrophysical research is not enough. For a detailed characterisation, it is necessary to use special pore space research methods. One of such methods is the NMR method that has been widely used in the study of petrophysical properties of oil and gas reservoirs [36–49] since the 1990s.

NMR studies typically include the measurement of transverse relaxation times T_2. A dominant mechanism of relaxing the nuclei of hydrogen atoms contained in fluids that saturate rocks is pore surface relaxation (surface relaxation). In case the void space of a rock sample is completely filled with one fluid and there is no magnetic field gradient, the transverse relaxation time T_2 is determined by the following expression [36, 37]:

$$\frac{1}{T_2} = \rho \frac{S}{V}, \qquad (2)$$

where T_2 is the transverse relaxation time, ms; ρ is the relaxation activity of a rock, µm/ms; S/V is the specific surface area of the pore space, µm²/µm³.

In the above expression, the relation of the pore area (S) to its volume (V) is the function of the pore form and size. For example, if we consider the void space of a rock as a set of spheres or cylinders, then the specific surface area is $3/r$ and $2/r$, respectively (here r is the radius of the sphere or cylinder) [50]. Then, in its turn, the transverse relaxation time T_2 is proportional to the pore radius. Generally, the more the modal value of the transverse relaxation time T_2 is, the more the size of the pores composing the void space is, and therefore the relation of the free fluid index to the bound fluid index (Fig. 2) is higher.

To solve the petrotypification problem, the following two indicators are proposed:

1. A structural parameter (let us call it N) [51] that is determined by the results of standard studies and is equal to:

$$N = \sqrt{\frac{K_{пр}}{K_{оп}}}, \qquad (3)$$

where N is the structural parameter, mD$^{0.5}$; $K_{пр}$ is the absolute gas permeability coefficient, mD; $K_{оп}$ is the open porosity coefficient, unit fractions.

Based on the dimensional analysis, this parameter corresponds to the radius of the pore channels and reflects the rock filtration potential. Basically, this magnitude characterises the relationship between permeability and porosity and determines the reservoir type (porous, porous-vuggy, fractured, etc.). The structural parameter was chosen by the authors to identify petrophysical types due to the fact that it is sensitive to the presence of open fractures and stylolites in core samples: when they develop (in case of the same porosity values), permeability and, consequently, the structural parameter increase significantly.

2. The relation of the free fluid index to the bound fluid index (let us call it M) that is determined by the NMR data and is equal to:

$$M = \frac{FFI}{BVI}, \qquad (4)$$

where M is the relation of the free fluid index to the bound fluid index, units; FFI is the free fluid index (equal to the

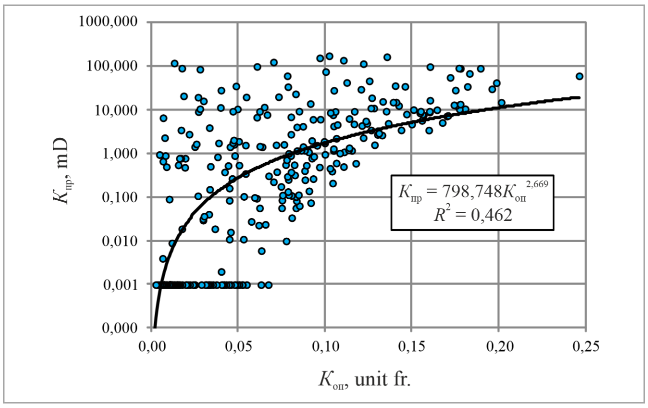


Fig. 1. Dependence of the absolute gas permeability coefficient on the open porosity coefficient

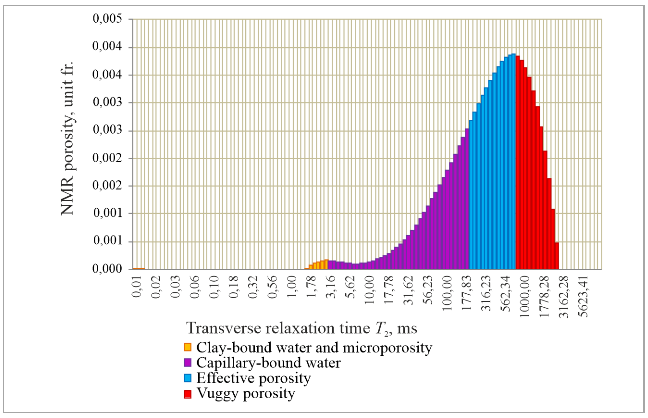


Fig. 2. Distribution of the NMR porosity according to the transverse relaxation times T_2, sample No. 38-149-19

sum of contributions to the total porosity of effective and vuggy porosities), unit fr.; BVI is the bound fluid index (equal to the sum of contributions to the total porosity of clay-bound water and microporosity and capillary-bound water), unit fr. (see Fig. 2). The given relation is used in the free fluid model (Coates model) when predicting the permeability coefficient according to NMR data [36, 37]. This indicator reflects the rock volumetric potential and was chosen by the authors due to the fact that it is sensitive to the manifestation of leaching processes in deposits and, consequently, to the development of vugs: with an increase in the proportion of a vuggy component in the void space of rocks, this parameter increases.

To further identify petrophysical types, we introduce a complex parameter that is equal to:

$$P_{комп} = \frac{N}{M} = \frac{\sqrt{\dfrac{K_{пр}}{K_{оп}}}}{\dfrac{FFI}{BVI}}. \qquad (5)$$

As mentioned above, the deposits under study were significantly affected by secondary transformation processes. Among all processes, calcitisation (fracture healing in particular), stylolitisation, open fracture formation and leaching have the greatest influence on the structure of the void space.

Figure 3 shows a cumulative curve of the decimal logarithm of the complex parameter superimposed on the distribution chart of the above processes according to the intervals of the decimal logarithm of the complex parameter. In the distribution chart of post-sedimentation processes along the axis of abscissas, the decimal logarithm of the complex parameter at a pitch of 0.5 is drawn, and along the axis of ordinates – the proportion of thin sections where there is a manifestation of a specific process of the total number of thin sections in this interval of the complex parameter. The chart shows that different intervals of the complex parameter are characterised by the predominant influence of certain secondary transformations, which indicates that the value of the complex parameter (and therefore the structure of the void space) of the deposits under study is determined by the manifestation of specific post-sedimentation processes.

To divide samples into petrotypes, linear areas were marked on the cumulative curve. It should be noted that the boundaries of the linear areas were adjusted to take into account information on secondary processes obtained from the microlithological description of thin sections.

It is worth noting that the physical meaning of the above complex parameter is the relation of the rock filtration potential to the volumetric one, and it is used due to the necessity of using a set of petrophysical characteristics when identifying and describing petrophysical types of carbonate rocks. If we mark the parameter $N = \sqrt{\frac{K_{пр}}{K_{оп}}}$ along the axis of ordinates, and the indicator $M = \frac{FFI}{BVI}$ along the axis of abscissas, then the points that lie in one cloud of correlation will have a similar structure of the void space and therefore will belong to the same petrophysical type.

Characterisation of the Identified Petrophysical Types

A joint analysis of the petrographic description of thin sections, the results of capillarimetric, NMR and standard studies allowed us to discover the characteristic features of the void space and the effect of post-sedimentation processes on it for the identified petrophysical types.

Table 1 shows the structure of the void space of the identified types of rocks and statistical characteristics of petrophysical properties that quantify it: structural parameter (N); relation of the free fluid index to the bound fluid index (M); logarithmic mean value of the transverse relaxation times (T_2logmean) to be determined by NMR studies; electric tortuosity of the pore channels ($T_{эл}$) to be determined by the results of measuring the open porosity coefficient and specific electrical resistance (CER) (for rocks with the simplest pore geometry $T_{эл} = 1$, $T_{эл}$ increases as the void geometry becomes complicated); mean radius of the pore channels ($R_{пор}$) determined from capillarimetric studies; absolute gas permeability coefficients ($K_{пр}$), open porosity coefficients ($K_{оп}$) and residual water saturation coefficients ($K_{ов}$).

Table 2 shows the frequency of secondary transformation manifestations for the identified petrotypes.

During the analysis, the identified petrophysical types were combined into four zones: development of healed fracturing (PRT 1), development of leaching (PRT 2–4), development of leaching and open fracturing (PRT 5), development of open fracturing (PRT 6).

The Healed Fracturing Development Zone

PRT 1: based on the petrographic description of thin sections, the void space (approximately 5 %) is represented by the pores about 0.3 mm in size, intraform, trace, less often interform ones, as well as by multi-directional fractures mineralised with calcite (approximately 0.4 mm thick) that connect calcitated areas (see Table 1). It is characterised by the predominant development of calcification processes (filling of intraform vugs and fractures), as well as by the presence of healed fractures (see Table 2). The FVP (filtration-volumetric properties) of this petrophysical type are determined mainly by pores.

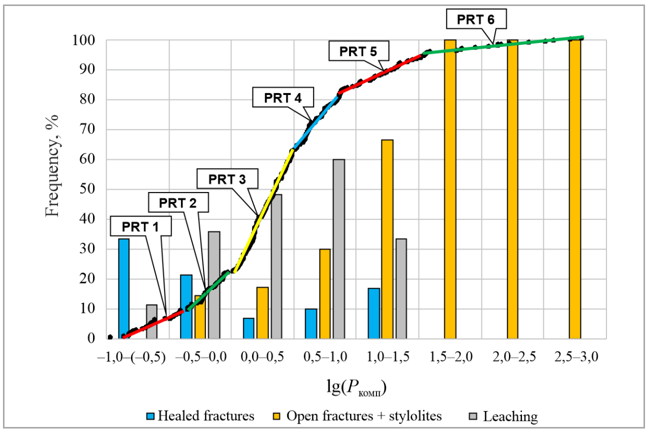


Fig. 3. Cumulative curve of the parameter lg($P_{комп}$) combined with the secondary transformation distribution chart according to the complex parameter intervals

The Leaching Development Zone

PRT 2: based on the petrographic description of thin sections, the void space (about 7 %, sometimes it reaches 10 %) is presented by the pores about 0.4 mm in size, as a rule, trace, often intraform and unstructured, isolated ones, of isometric and extended forms, sometimes by the vugs about 2.4 mm in size and of irregular and extended forms (see. Table 1). It is characterised by the manifestation of post-sedimentation calcitisation processes (sparitic calcite in internal vugs and regeneration borders), as well as recrystallisation, less often leaching (see Table 2). The FVP of this type are determined by pores and partially by vugs (porous-vuggy reservoir, mainly porous).

PRT 3: according to the microlithological description, the void space (approximately 9 %, sometimes it reaches 15 %) is represented by the pores about 0.5 mm in size, intraform, trace and unstructured, isolated ones, of irregular, extended and isometric forms, by the vugs about 4 mm in size, usually trace, less often intraform ones, of irregular and extended forms (see Table 1) It is characterised by the predominant development of calcitisation processes (sparitic calcite in intraform vugs, regeneration borders and fractures), recrystallisation, leaching and dolomitisation (see Table 2). The FVP of this type are determined by pores and vugs (porous-vuggy reservoir).

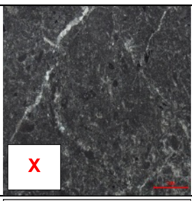
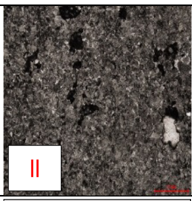
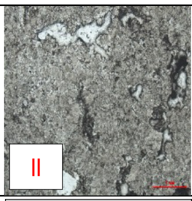
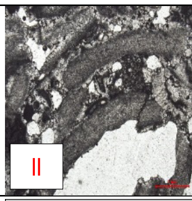
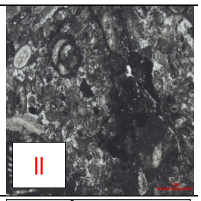
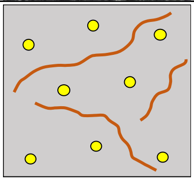
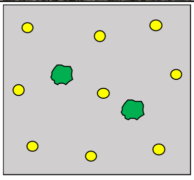
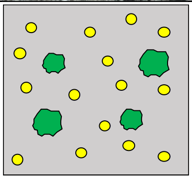
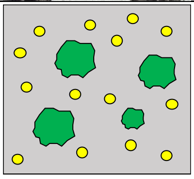
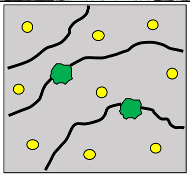
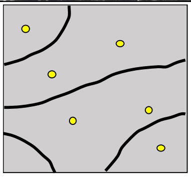
PRT 4: based on the microdescription of thin sections, the void space (about 13 %, it reaches 15 %) is represented by the pores up to 1 mm in size, trace, leaching, intergranular, isolated ones, of extended and irregular forms, by the vugs about 4.7 mm in size and of extended and irregular forms (see Table 1). It is characterised by the predominant development of calcitisation, recrystallisation and leaching processes (see Table 2). The FVP of this type are determined by pores and vugs (porous-vuggy reservoir).

The Open Fracturing and Leaching Development Zone

PRT 5: based on the lithological microdescription of thin sections, the void space (about 7 %) is represented by the pores about 0.3 mm in size, isolated, trace, intraform ones, sometimes by the vugs of irregular and extended forms, up to 3.2 mm in size, by the open fractures up to 0.5 mm thick and the stylolites with an amplitude of up to 5 mm (see Table 1). It is characterised by the predominant development of calcitisation, recrystallisation, fracture formation processes (see Table 2). The FVP of this type are determined mainly by pores and fractures, partially by vugs (fractured-porous-vuggy reservoir, mainly fractured-porous).

Table 1

Petrophysical characteristics of the identified petrotypes

Characteristic	PRT 1	PRT 2	PRT 3	PRT 4	PRT 5	PRT 6
Photos of thin sections (X – crossed nicols, || – parallel nicols)	 X	 ||	 ||	 ||	 ||	 ||
Schematic structure of the void space	 Healed fractures Pores	 Pores Vugs	 Pores Vugs	 Pores Vugs	 Pores Vugs Open fractures	 Open fractures Pores
N, mD$^{0.5}$	0.16 ± 0.05 0.12–0.31	1.17 ± 0.80 0.16–2.26	5.27 ± 3.83 0.96–15.61	17.19 ± 10.02 4.37–34.79	20.22 ± 11.71 5.37–41.10	34.94 ± 24.61 18.32–71.48
M, units	0.78 ± 0.28 0.43–1.24	1.82 ± 1.40 0.33–4.66	2.81 ± 1.91 0.46–9.47	3.90 ± 3.01 1.19–10.08	1.21 ± 0.45 0.69–1.86	0.36 ± 0.27 0.15–0.74
T_2 logmean, ms	176.945 ± 65.729 99.554–317.157	252.201 ± 129.316 66.656–439.841	345.530 ± 139.909 46.853–600.232	460.213 ± 238.067 225.737–871.989	198.306 ± 95.571 75.684–365.248	78.740 ± 62.587 15.327–140.467
$T_{эл}$, units	4.17 ± 0.40 3.75–5.04	3.88 ± 0.41 3.20–4.68	2.90 ± 0.50 1.88–4.35	3.02 ± 0.54 2.44–3.81	3.04 ± 0.53 2.60–4.07	2.95 ± 0.40 2.59–3.38
$R_{пор}$, μm	1.975 ± 0.460 1.303–2.561	2.515 ± 1.349 1.488–6.473	3.831 ± 1.936 0.900–8.559	8.109 ± 3.959 3.143–13.600	5.281 ± 3.327 1.884–10.551	3.268 ± 0.559 2.873–3.663
$K_{пр}$, mD	0.001 0.001–0.034	0.031 0.001–0.599	0.346 0.001–59.994	0.599 0.001–163.960	1.636 0.001–172.782	4.709 0.001–118.030
$K_{оп}$, %	4.70 ± 1.36 3.12–8.08	6.67 ± 2.95 1.99–11.76	9.21 ± 5.85 1.01–24.61	7.36 ± 5.68 0.64–18.93	4.70 ± 3.36 0.34–12.20	1.95 ± 1.52 0.26–6.08
$K_{ов}$, %	57.98 ± 5.63 48.52–63.71	39.31 ± 18.56 15.02–71.18	29.10 ± 14.44 7.21–63.47	24.10 ± 10.77 13.73–40.03	39.64 ± 8.09 27.38–51.26	62.17 ± 13.81 53.84–78.12

Note: the numerator indicates the arithmetic mean value (for the permeability coefficient – geometric mean) ± the standard deviation (it is not indicated for the permeability coefficient due to abnormal distribution), the denominator indicated the range of values.

Table 2

Frequency of the secondary transformation manifestations for the identified petrotypes

Characteristic	Proportion of the thin sections with such characteristics, %					
	PRT 1	PRT 2	PRT 3	PRT 4	PRT 5	PRT 6
Calcitisation	100.00	84.62	96.67	100.00	100.00	100.00
Recrystallisation	10.00	69.23	40.00	57.14	50.00	50.00
Stylolitisation	10.00	0.00	13.33	28.57	25.00	50.00
Open fractures	0.00	7.69	3.33	0.00	37.50	50.00
Healed fractures	40.00	15.38	6.67	0.00	25.00	0.00
Silicification	0.00	0.00	10.00	0.00	12.50	50.00
Dolomitisation	10.00	7.69	36.67	28.57	0.00	0.00
Leaching	10.00	38.46	46.67	85.71	25.00	0.00

The Open Fracturing Development Zone

PRT 6: based on the microdescription of thin sections, the void space (about 2 %) is represented by the trace, intraform pores, of fractured type, of isometric and extended forms, by open fractures, stylolites made of brown clay matter (see Table 1). It is characterised by the predominant manifestation of calcitisation, recrystallisation, stylolitisation, fracture formation and silicification processes (see Table 2). The FVP of this type are determined mainly by fractures (fractured reservoir).

For the studied set of samples, the main diagnostic signs of differences in the structure of the void space of the identified petrophysical types were established according to the capillarimetric and NMR studies. According to many authors [41, 48, 49], the capillarimetric studies (semipermeable membrane method) provide information about the mouth of the pore channels, while the NMR ones characterise to a greater extent the body of the pore itself.

Figure 4 shows the averaged size distributions of the pore channels determined by the capillarimetric studies (semipermeable membrane method), as well as the averaged distributions of the normalised NMR porosity values according to the transverse relaxation times T_2 for the identified petrophysical types. A detailed analysis of the averaged data allowed us to discover a change in the results of studies of the two methods associated with the special features of the pore space structure of the identified petrotypes.

It can be seen from Figure 4, *a*, that for all the petrophysical types there is a predominant content of pore channels with a radius of less than 0.12 μm in the void space. A similar pattern can be observed from the results of the NMR studies (Fig. 4, *b*): the modal distribution values of the transverse relaxation times for the1st–5th types are approximately equal and range from 200 to 447 ms, an exception is the 6th petrophysical type with a modal value of about 89 ms, this smaller time shift is due to the presence of smaller voids, and its establishment is a result of a higher resolution capability of the NMR method compared to the semipermeable membrane method.

From the 1st to the 4th petrophysical types, there is a decrease in the proportion of the pore channels with a radius of less than 0.12 μm from 57.98 % for the 1st type to 21.96 % for

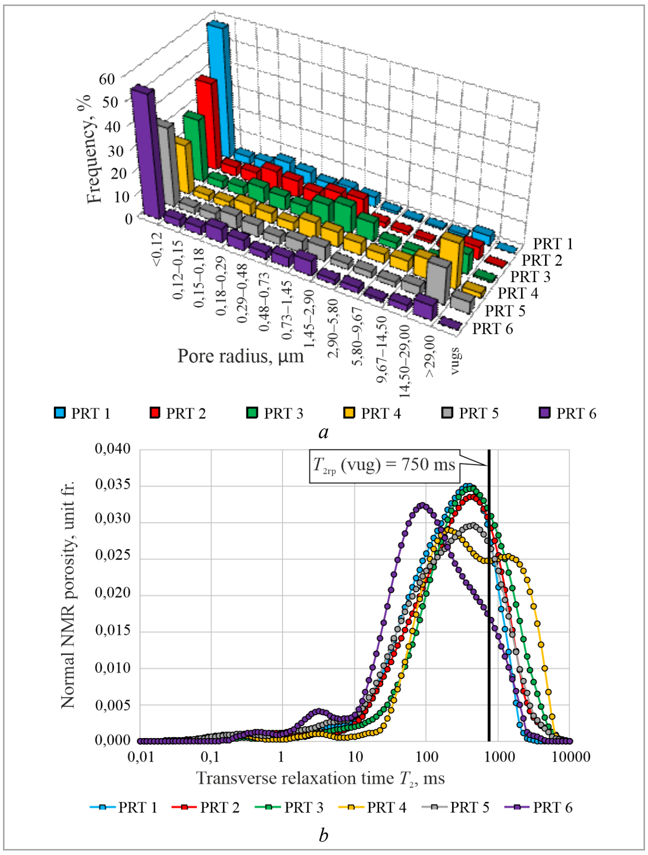


Fig. 4. Averaged distributions: *a* – pore channels according to the sizes of the identified petrophysical types; *b* – normalised NMR porosity values according to the transverse relaxation times T_2 of the identified petrophysical types

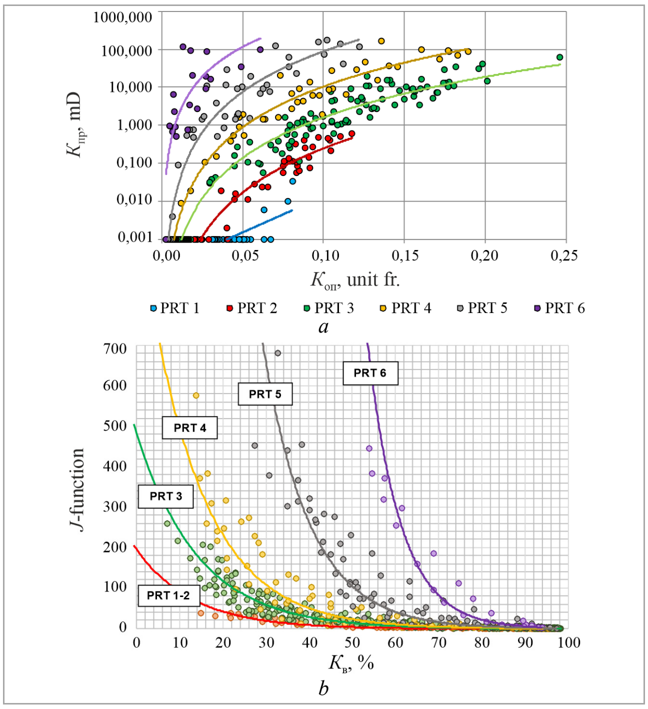


Fig. 5. For the identified petrophysical types: *a* – permeability dependencies on porosity (diagrams); *b* – determination of water saturation values according to the *J*-function (nomogram)

the 4th one. At the same time, there is an increased contribution to the total volume of the void space of larger pore channels: first within the range of 0.18–2.90 µm for the 2nd petrotype as compared to the 1st one, then within the range of 1.45–5.80 µm and more than 29 µm for the 3rd petrophysical type as compared to the 2nd one, and, finally, there is a significant increase in the content of pore channels with a radius of more than 29 µm for the 4th petrophysical type, which leads to a bimodal distribution of pore channels. According to the NMR data, from the 1st to the 4th petrophysical type there is an increase in the vuggy component (a standard cut-off of 750 ms for identifying the vuggy component is made as a vertical line in Fig. 4, *b*) from 13.64 % for the 1st petrotype to 40.00 % for the 4th type. According to the NMR results, similar to the data obtained during the interpretation of the capillarimetric studies, the presence of two groups of voids has been established for the 4th petrophysical type: the first group of voids is characterised by a modal value of transverse relaxation times of 200 ms, and the second–of about 1,413 ms. Most likely, the second mode corresponds to the relaxation time of the fluid in the vugs.

According to the interpretation of the NMR studies, the fifth petrophysical type is similar to the 2nd one, however, there is no such similarity according to the capillarimetric studies. Most likely, this is due to the presence of open fractures in the samples of the 5th petrotype established during the analysis of the lithological microdescription of petrographic thin sections: when overpressure increases in the capillarimetric chamber, gas displaces a significant amount of water from large pores connected by a system of fractures, as a result, an additional mode can be observed in the area of pore channels with a radius of more than 29 µm during the interpretation.

According to the capillarimetric studies, the sixth petrophysical type is identical to the 1st one, however, its volumetric properties are worse (the open porosity coefficients are 1.95 and 4.70 %, respectively).

Therefore, a comprehensive interpretation of the capillarimetric and NMR studies made it possible, on the one hand, to establish main differences between the petrophysical types and confirm the correctness of their identification and, on the other hand, to give their extended characterisation.

Construction of Some Petrophysical Dependences for the Identified Petrotypes

Figure 5, *a*, shows the dependences of the absolute gas permeability coefficient on the open porosity coefficient for the identified types. The results of experimental data approximation with exponential and power functions are given in Table 3: statistically significant determination coefficients are obtained [52].

The identified petrophysical types are quite well differentiated according to the Leverett *J*-function [53] (Fig. 5, *b*). It should be pointed out that the application of existing petrophysical typification methods does not give such a distinct differentiation as when using the approach developed by the authors.

The Leverett *J*-function is widely used by various authors to set an oil saturation cube in geological models of reservoirs [54–57]. This is especially relevant for heterogeneous, complex rocks in the section of which the determination of oil saturation of interlayers-reservoirs is impossible due to the fact that the size of a logging electric probe is larger than the thickness of an interlayer (carbonate reservoirs).

Figure 5, *b*, shows a nomogram for determining the values of the water saturation coefficient according to the *J*-function for the identified petrotypes, and Table 4 presents the dependences of the *J*-function on the water saturation coefficient for the identified petrophysical types; the 1st and 2nd petrophysical types were combined into one dependence due to the close location of data points. High values of the statistically significant determination coefficients (R^2) indicate the possibility of using these dependences to set an oil saturation cube in a geological model of a reservoir.

Conclusion

For the first time, the authors suggest a methodological approach to the identification of petrophysical types of complex carbonate rocks based on the integration of the results of standard (determination of the gas permeability and porosity coefficients) and special (NMR studies) core studies, as well as on data from the petrographic description of thin sections. The approach was applied for the identification of petrotypes in the section of the Asselian-Sakmarian deposits at the Yareyuskoye field: six petrophysical types were identified and described in detail, schematic models of the void space were built. Based on the comprehensive analysis of the capillarimetric and NMR studies, we discovered certain features and characteristic differences in the structure of the void space of various types of rocks. It has been established that the identified petrophysical types are traced according to the comparison diagrams of permeability and porosity, as well as to the Leverett *J*-function and water saturation, which allowed us to build individual and statistically significant dependences.

The obtained information will allow a differentiated approach to geological and hydrodynamic modeling and therefore it will allow to increase the accuracy of hydrocarbon reserve calculations and the efficiency of reservoir development planning.

Table 3

Functions of permeability dependence on porosity for the identified petrotypes

PRT	Equation	R^2
1	$K_{пр} = 0.0002e^{43.698Kоп}$	0.507 at $F(4.225) = 26.781, p < 0.05$
2	$K_{пр} = 1786.458К_{оп}^{3.862}$	0.913 at $F(4.105) = 388.287, p < 0.05$
3	$K_{пр} = 5628.786К_{оп}^{3.544}$	0.966 at $F(3.918) = 3523.059, p < 0.05$
4	$K_{пр} = 38435.753К_{оп}^{3.566}$	0.980 at $F(4.034) = 2450.000, p < 0.05$
5	$K_{пр} = 305975.023К_{оп}^{3.541}$	0.916 at $F(4.085) = 436.190, p < 0.05$
6	$K_{пр} = 286182.173К_{оп}^{2.608}$	0.595 at $F(4.451) = 24.975, p < 0.05$

Table 4

J-function dependences on the water saturation coefficient for the identified petrotypes

PRT	Equation	R^2
1–2	$J = 195.123e^{-0.076\,K_В}$	0.751 at $F(3.877) = 790.209, p < 0.05$
3	$J = 482.658e^{-0.070\,K_В}$	0.874 at $F(3.868) = 2483.270, p < 0.05$
4	$J = 1051.539e^{-0.076\,K_В}$	0.890 at $F(3.957) = 663.455, p < 0.05$
5	$J = 10206.319e^{-0.092\,K_В}$	0.845 at $F(3.942) = 512.452, p < 0.05$
6	$J = 749087.198e^{-0.130K_В}$	0.914 at $F(4.301) = 233.814, p < 0.05$

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