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ANALYSIS OF THE FRACTAL STRUCTURE AND STOCHASTIC DISTRIBUTION OF PORES IN OIL AND GAS RESERVOIRS

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ОЦЕНКА ФРАКТАЛЬНОЙ СТРУКТУРЫ И СТОХАСТИЧЕСКОГО РАСПРЕДЕЛЕНИЯ ПОРОВЫХ ПУСТОТ НЕФТЕНОСНЫХ КОЛЛЕКТОРОВ

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It is known that the natural potential of terrigenous reservoirs' capacity significantly depends on interparticle porosity and particle packing type. Other significant factors that impact reservoir porosity are the shape of particles and the proportion of content and distribution of particles of various sizes in the rock. The attempts to simulate a net effect of factors influencing the multimodal distribution of interparticle porosity are well known; some of them are discussed in this work. The simulated data will be compared with actual measured data, obtained from particle size distribution analysis of core samples from a well-known and long operated oil and gas field in Azerbaijan. For the purpose of the survey, these measured data were generalised and analysed in detail.

The research covers the most typical for the region particle size fractions: pelite, silt, fine-grained sand, and medium-grained sand. Pie charts of the particle size distribution analysis results indicate that in the first group of rocks (argillaceous silt sand) the largest portion is represented by 0.175 mm particle size fraction. Two other particle size fractions of 0.055 and 0.01 mm constitute approximately the same potions, and, finally, the coarse-grained fraction (0.25 mm) represents an insignificant part of the total rock volume and may be neglected.

Though the apparent correlation between porosity quality and such factors as particle size distribution and mechanical densification of sediments were identified, still the calculated paired correlation coefficient between particle size fractions and parameters, used to average particle size distribution and sort rocks by their type have shown that these are two independent and unrelated functional dependencies. At the same time, the influence of particular fractions and, which is more important, the influence of their proportions on the interparticle porosity is not the same. A more detailed simulation of multimodal distribution has shown that in this case, the use of fractal concepts proved to be more efficient. As an alternative, we have analysed a method for the evaluation of rock oil-bearing properties based on calculated dependence between the fractality index and oil saturation.

Известно, что природный потенциал продуктивной вместимости терригенных коллекторов в значительной степени определяется их межзерновой пористостью и характером упаковки зерен. Однако, помимо этого, на пористость коллекторов большое влияние оказывают форма зерен, а также соотношение содержания и распределения зерен различных размеров в объеме породы. Широко известны попытки моделирования результирующего эффекта влияющих факторов на мультимодальное распределение межзерновой пористости, некоторые из которых рассматриваются в данной работе. Вместе с тем для сравнения с реальными данными здесь также описаны детальные аналитические обобщения фактических результатов гранулометрического анализа керна из скважин одного из известных и длительно эксплуатируемых нефтегазовых месторождений Азербайджана.

Исследованиями были охвачены наиболее характерные для региона пелитовая, алевритовая, мелкозернистая песчаная и среднезернистая песчаная фракции. Результаты исследований по распределению фракций представлены в виде круговых диаграмм, анализ которых показывает, что в составе первой группы пород (глинисто-алевритовых песках) доминирует фракция с размером зерен 0,175 мм. Две другие фракции с размером зерен 0,055 и 0,01 мм занимают примерно одинаковый объем, наконец, фракция грубых зерен (0,25 мм) составляет незначительную часть объема и может не учитываться.

Установленные закономерности изменения пористости в зависимости от фракционного состава и механического уплотнения осадков весьма показательны, однако вычисление парного коэффициента корреляции между фракциями и параметрами, усредняющими гранулометрический состав и отражающими сортированность пород, показало, что они являются самостоятельными, не связанными между собой функциональными зависимостями. При этом влияние отдельных фракций, а главное – их соотношения на величину межзерновой пористости неодинаково. Детализация процесса моделирования мультимодального распределения позволила установить, что в данном вопросе более эффективно применение фрактальных концепций. Как вариант рассмотрен способ оценки коллекторских свойств нефтесодержащих пород на основе расчетной зависимости между показателем фрактальности и нефтенасыщенностью.

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Introduction

On the one hand, the efficiency of oil and gas filed development process and hydrocarbon extraction of productive strata significantly depends on the initial permeability and porosity properties of reservoir rocks. On the other hand, in the process of development and large-scale intrastratal filtration of fluids, different types of deformation processes occur in a stratum: from elastic deformation to plastic fracture [1–5]. These processes, in their turn, cause secondary changes in permeability and porosity properties of reservoir rocks [6–9].

For instance, plastic fracture of a stratum may cause a change in the pore volume by the increase in the specific surface area of particles, which leads to the reduction of the reservoir pressure [10, 11], as it is known that

$$P = \frac{F}{S},$$

where F is the load (reservoir pressure); S is the pore surface area (the surface area of rock-forming particles).

This results in conditions conducive to abnormally low reservoir pressure. This particular case is based on the assumption that oil and gas-bearing rocks are porous or fractured rock media characterized by a random distribution of rock-forming particles, shape and size of capillaries and cracks [10, 12]. In such rock environments, effective reservoir pressure is one of the main factors of intrastratal migration and smooth extraction of hydrocarbons [11]. This is a counter-pressure of fluid accumulated in rock pores to the rock pressure exerted by the weight of the overlying strata. The value of the effective reservoir pressure is calculated as follows:

$$P_{\text{eff}} = P_{\text{rock}} - P_{\text{pore}},$$

where P_{rock} is the rock pressure; P_{pore} is the reservoir pressure.

When pores are saturated with gases, the response of fluid can be neglected, otherwise liquid fluids (water and oil) are the main factors determining the reservoir pressure counteracting the rock pressure.
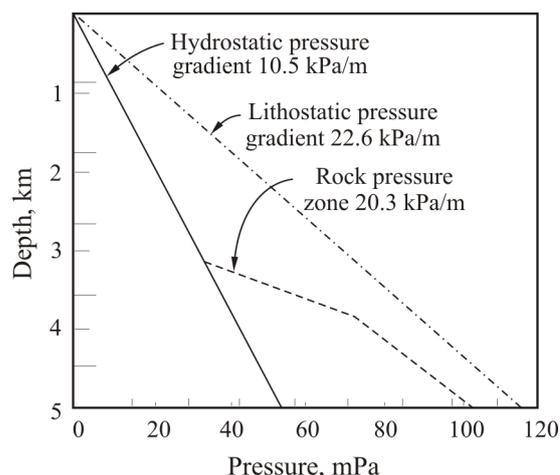
Fig. 1. Measured downwards average gradient and high pressure area [21]
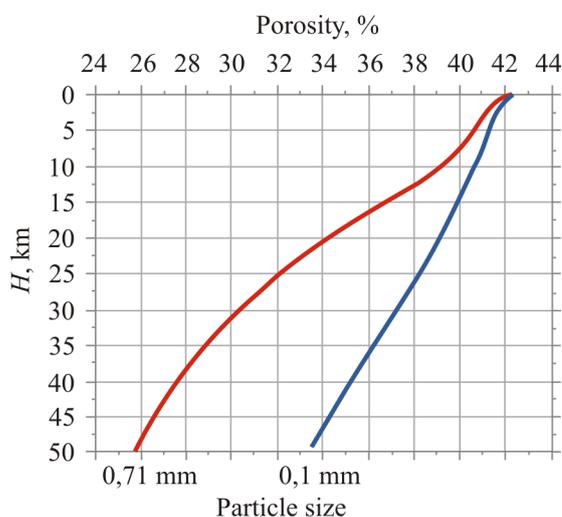
Fig. 2. Downwards mechanical densification of well-sorted sand [10]

Statement of the problem

Multiple theoretic calculations and in situ measurements in deep wells [13–20] allow us to obtain values of subterranean lithostatic and hydrostatic pressures which can be represented numerically by gradients of lithostatic and hydrostatic pressures. For instance, the lithostatic pressure gradient is determined based on the sedimentation rate, which contributes to the degree of densification and bulk density of rock particles. The hydrostatic gradient is calculated based on the density and height of a liquid column. In Figure 1, provides an example of downwards lithostatic and hydrostatic gradient measurement; it shows that the hydrostatic pressure gradient is 10.5 kPa/m, and the lithostatic gradient is 22.6 kPa/m, i.e. approximately two times higher.
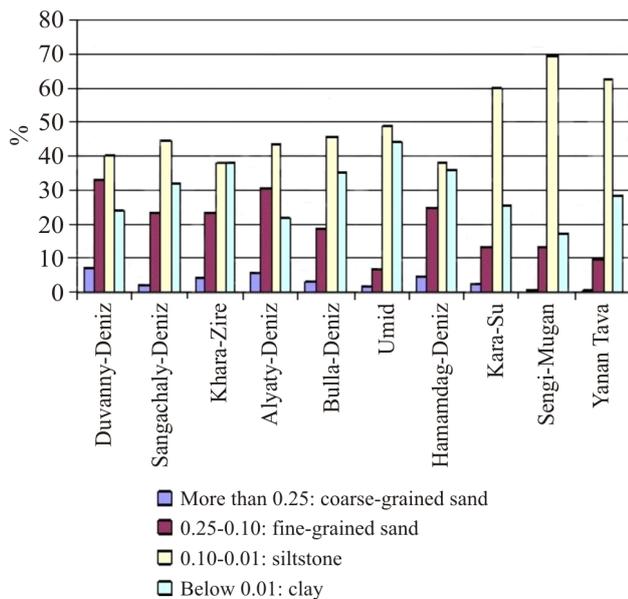
Fig. 3. Various particle size distributions in terrigenous reservoirs in some oil and gas fields of Azerbaijan

Under stable conditions, contacts between separate particles cause adhesion increased by gravity. However, in the process of densification, the contact forces between particles are neutralized, the friction between particles tends to zero, and quicksands develop (the liquefaction of sands) [10, 22–28]. In short, the process of sediments mechanical densification can be described through the example of well-sorted sand (Figure 2): at the initial stage of sedimentation (at a depth of 0–2 km), well-sorted sand, being free, still can be significantly compressed. For instance, test densification of loose sand having its initial porosity of 40–42 % shows that at 20–30 MPa load porosity can decrease down to 35–25 % depending on the strength and size of particles, which corresponds to the conditions experienced by rocks under normal rock pressure at the depth of 2–3 km. In these conditions, well-sorted coarse sand is more compressible than fine-grained sand [29–31]. Therefore, the increased pressure reduces the effective pressure but maintains porosity due to the reduction of mechanical densification. At the same time, the porosity change under mechanical densification can differ significantly depending on the textural and mineralogical composition, which widely uses data of the particle size distribution analysis.

In addition to the above, fine-grained environments (having pore sizes up to 0.1 nm) can be described as systems having a fractal structure characteristic of random distributions of pores, capillaries, and fracture channels [29, 32–35]. The use of fractal principles for the development of hydrocarbon fields facilitates the analysis of the turbulent flow of fluid and gas within reservoir pores.

Main Points

The studies of the pore volume densification patterns in productive reservoirs and the correlation between the specific surface area and oil saturation described in this work used analysis of generalised data from a well-known and long operated oil and gas field in Azerbaijan [36] (Table 1). However, as we know, the specific surface area of pore volume in terrigenous sediments is determined by particle size distribution in the rock matrix. Therefore, before calculating the specific surface area, we analysed data on particle size distribution in the core material and determined the degree of the influence of particular fractions (including prevailing particle size fractions) on the porosity of different reservoirs. Thus the analysed core samples were divided into four groups depending on the rock type: argillaceous-silty sand, argillo-arenaceous siltstone, sandy-argillaceous siltstone, and argillaceous sandy loam.

The following four groups were formed based on the particle (grain) size: pelite (0.01 mm and less), silt (0.055 mm), fine-grained sand (0.175 mm) and medium-grained sand (0.25 mm). The selected grading of particle sizes of rock-forming particles is commonly accepted in the fields of the region [25–26, 39] and is shown in Figure 3.

The results of our analyses of the particle size distribution of the studied groups are given in Figure 4 as pie charts; the figure shows that in the first group of rocks (argillaceous-silty sand) the fraction having particle size of 0.175 mm prevails. Other two fractions - having a particle size of 0.055 and 0.01 mm - represent almost similar portions, and, finally, the coarse-grained fraction (0.25 mm) is represented by an insignificant portion and may be neglected.

Table 2 describes the correlation between the porosity of the studied rocks and prevailing and secondary particle sizes.

This data shows that an increase in the prevailing fraction (0.175 mm) content in the first group of rocks (argillaceous-silty sand) leads to porosity increase, whereas an increase in the content of the fraction having a particle size of 0.055 mm reduces the porosity of this group of rocks. In the remaining three groups of rocks, the fraction having a particle size of 0.055 mm prevails, and the percentage of

fractions having a particle size of 0.175 and 0.01 mm is different. Here, in the same way, as in the first group of rocks, the coarse-grained fraction (0.25 mm) is represented by an insignificant portion and may be neglected.

As for the argillo-arenaceous siltstone group of rocks, we revealed the influence of the prevailing fraction (0.055 mm) and fraction having a particle size of 0.175 mm (see Table 2) on porosity.

These data demonstrate that an increase in the content of the prevailing fraction and fraction having a particle size of 0.175 mm in argillo-arenaceous siltstone leads to increased porosity.

As opposed to the argillo-arenaceous siltstone group, the prevailing fraction (0,055 mm) and a coarser fraction (0,25 mm) have a negative effect on the porosity of sandy-argillaceous siltstone.

And finally, for the last group – the argillaceous sandy loam group – the influence of the prevailing (0.055 mm, fine) and secondary (0.175 mm, coarser) fractions is contrary (the same way as in the argillaceous-silty sand group). In particular, an increase in the fine (0.055 mm, prevailing) fraction content in argillaceous sandy loam leads to porosity reduction, whereas an increase in the coarser fraction (0.175 mm) content increases the porosity of argillaceous sandy loam (see Table 2).

Table 1

Average values of particle size distribution, porosity, specific pores surface area,
and oil and gas bearing capacity of the studied rock types

Rock type (number of samples)	Particle size fraction, mm %				Porosity	Specific surface area	Oil content
	0.25	0.175	0.055	0.01			
Argillaceous-silty sand (14)	2.44	54.13	28.01	15.31	25.62	1266	15.2
Argillo-arenaceous siltstone (6)	0.39	27.49	55.54	16.58	25.04	1725	16.74
Sandy-argillaceous siltstone (3)	0.37	12.43	60.41	26.90	23.07	1851	15.18
Argillaceous sandy loam (5)	0.68	39.38	43.91	16.59	24.56	1611	17.53
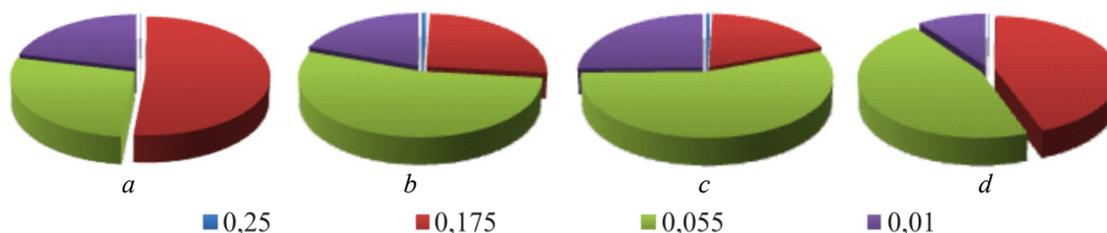
Fig. 4. Particle size distribution by groups of rocks: *a* – argillaceous-silty sand;
b – argillo-arenaceous siltstone; *c* – sandy-argillaceous siltstone; *d* – argillaceous sandy loam

Table 2

The influence of particle size distribution on the porosity
of different types of rocks

Group of rocks	Particle size, mm	Dependence of porosity and particle size distribution
Argillaceous-silty sand	0.175	$Y=0.3312X+7.14$
	0.055	$Y= -0.1376X+29.196$
Argillo-arenaceous siltstone	0.055	$Y=0.6338X+ 37.926$
	0.175	$Y=0.4875X+ 10.75$
Sandy-argillaceous siltstone	0.055	$Y= -1.9775X+ 106.04$
	0.25	$Y= -27.774X+70.73$
Argillaceous sandy loam	0.055	$Y=0.3312X+7.14$
	0.175	$Y=0.3312X+7.14$

Though the revealed dependence of porosity patterns changes on the particle size distribution and mechanical densification of sediments is quite obvious, still, as we have mentioned above, porosity may vary significantly depending on the textural and mineralogical composition of rocks. This is well demonstrated by the researches [10] where the dependence of porosity on mechanical densification was defined using also the parameters averaging particle size distribution in rocks (M_d – coarseness), and the coefficients showing sediment sorting (K_{sort}, Hr, and M_f – the maximum content of any particle size fraction). The paired correlation analysis of the fractions and the parameters averaging particle size distribution and reflecting sorting of rocks is shown in Table 3. This data show that the averaged particle size (on the one hand) and sorting of rocks (on the other hand) are independent and unrelated functional dependencies. At the same time, there is a close correlation between some parameters (for instance, rock coarseness and M_d).

Particle size. It is well known that the influence of particle size on interparticle porosity of rocks with random packing of spherical particles depends on the stability of active internal frictional forces and adhesion between separate particles [1]. These forces are proportional to the specific surface area of particles which is taken as equal to the total surface area of particles per unit of solid volume and are inversely proportional to particle size. Such dependency means that with all other factors being equal, in case of lower porosity the contribution of coarse particles is much less than the contribution of fine particles [37–44]. This general rule is shown in Figure 3, which demonstrates that an increase in the porosity of the sedimentary rock, having particles of a particular size, becomes significant only when particles size is lower than 0.1 mm (100 microns). In case of coarser sizes (over 100 mm), frictional forces decrease and porosity goes down to a state of random packing without frictional forces, which occurs when porosity is 0.399, and in this state, porosity does not depend on particle size any more.

Further porosity decrease is not possible for randomly packed spherical particles, except for the cases when particles are subject to irreversible deformation as a result of dissolution, recrystallization, destruction, plastic flow, etc. Such porosity decrease is called particle packing compaction.

Particle packing. In theoretical geometry, there are several patterns of standard particle packing in rocks exhibiting maximum possible interparticle porosity values (Table 4, Figure 5). It has also been revealed [21, 39–44], that the theoretical maximum porosity (0.476) of sedimentary rock having cubic packing of spherical particles of the same size does not depend on particle size.

Table 3

Paired coefficients of correlation between particle size fractions and parameters averaging particle size distribution and reflecting sorting of rocks

Parameter		Particle size fractions and their particle sizes, mm						Coefficient					
		F_1	F_2	F_3	F_4	F_5	F_6	M_d	Rock coarseness	K_{sort}	So	Hr	M_f
		1–0.5	0.5–0.25	0.25–0.1	0.1–0.05	0.05–0.01	< 0.01						
Coefficients	M_f	–0.07	–0.17	–0.32	–0.67	–0.27	–0.85	–0.5	0.56	0.22	0.27	–0.93	
	Hr	0.15	0.27	0.47	0.71	0.03	0.86	0.58	0.7	–0.7	–0.24		
	So	0.07	0.06	–0.48	–0.46	0.09	0.61	–0.73	–0.54	0.97			
	K_{sort}	0.08	0.07	–0.35	–0.38	0.007	0.5	–0.61	–0.41				
	Rock coarseness	0.24	0.3	0.91	0.51	–0.39	–0.81	0.93					
	M_d	–0.007	0.08	0.9	0.53	–0.35	–0.83						
Particle size fractions and their sizes, mm	F_6(below 0.01)	–0.03	–0.12	–0.62	–0.75	–0.05							
	F_5(0.05–0.01)	0.008	–0.04	–0.49	–0.22								
	F_4(0.1–0.05)	–0.04	0.02	0.25									
	F_3(0.25–0.1)	–0.009	0.09										
	F_2(0.5–0.25)	0.57											
	F_1(1–0.5)												

Shape of particles and distribution of particles of different sizes in the rock. Table 5 presents information on the dependency between various shapes of particles and interparticle porosity; Figure 6 compares rounded and angular particles and proves that porosity is higher when more angular particles are present in rock than in case of sub-spherical particles rock composition [21, 39–44].

Table 4

Maximum porosity
for different packing patterns

Packing	Maximum porosity
Random	0.399 and more (particle size-dependent)
Cubical	0.476
Rhombic	0.395
Rhombohedral	0.260
Tetragonal	0.302

Table 5

Dependence of particle shape
and interparticle porosity

Particle shape	Interparticle porosity (max)
Spherical	0.399
Cubical	0.425
Cylindrical	0.429
Disk-shaped	0.453

It has already been mentioned above that apart from particles shape the proportions of particle size fractions (particles of various sizes) content in the rock volume and their distribution influence the reservoir porosity very much, and the influence of particular fractions and (which is more important)

the influence of their proportion on interparticle porosity differs. It is rather difficult to simulate the actual distribution of particle sizes in a rock, which is often multimodal in nature; therefore, to better understand the net effect, the boundary conditions of calculations are simplified down to a variable mixture of particles of two sizes in a limited amount of the rock volume [21].

A schematic description of the simulation process is provided in Figure 7, where a rock model consists of particles of two sizes, one of which is 1/100 of the diameter of the other. There are two possibilities here:

– in the first case, the rock has a sufficient amount of coarse particles representing the general rock matrix, and the added smaller particles reduce the rock porosity because finer particles fill spaces between coarser particles (see Figure 7, *a*);

– in the second case, the general the rock matrix consists of finer particles. Here the pores are between fine particles (see Figure 7, *b*).

It is clear that if some amount of fine particles is removed and replaced with solid coarse particles, porosity will decrease, as in this case a portion of small particles contributing to certain porosity is replaced with continuous massive material having no internal porosity. In Figure 7 continuous lines *GR* and *RF* or *RM* represent theoretical curves for both cases. It is interesting to note that as the difference in particle size grows from 6:3 to 50:5, the actual porosity approaches theoretical values. It has been also noted that the minimum porosity is not impacted by the correlation of particle diameters. This minimum porosity corresponds approximately to 20–30 % of the diameter of smaller particles. It should also be noted that porosity of a mixture of two sizes is always lower than in any pure phase [21].

Cubical (47.6 %)   Hexagonal (39.5 %)   Rhomboidal (26.0 %)   Orthorhombic (39.5 %)   Tetragonal (30.2 %)
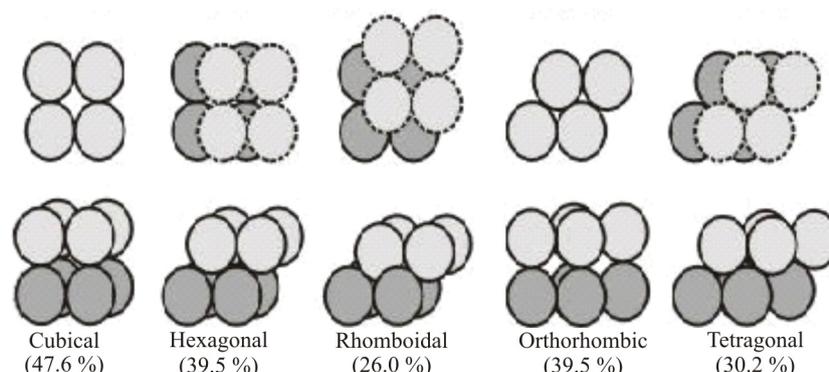
Fig. 5. Interparticle porosity for standard packing patterns
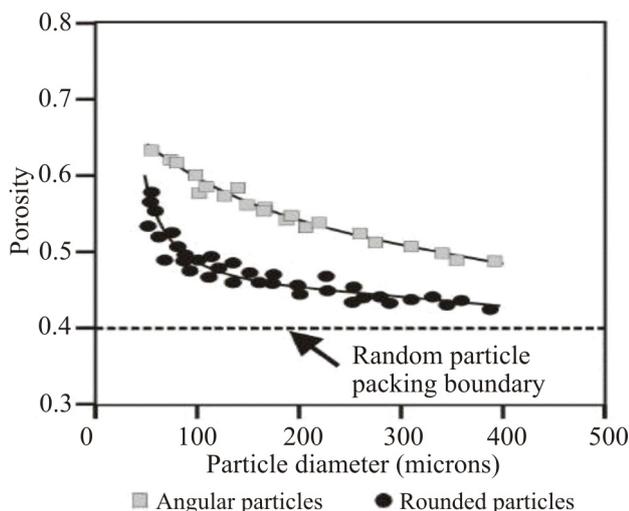
Fig. 6. The dependence of porosity on particle size [42]
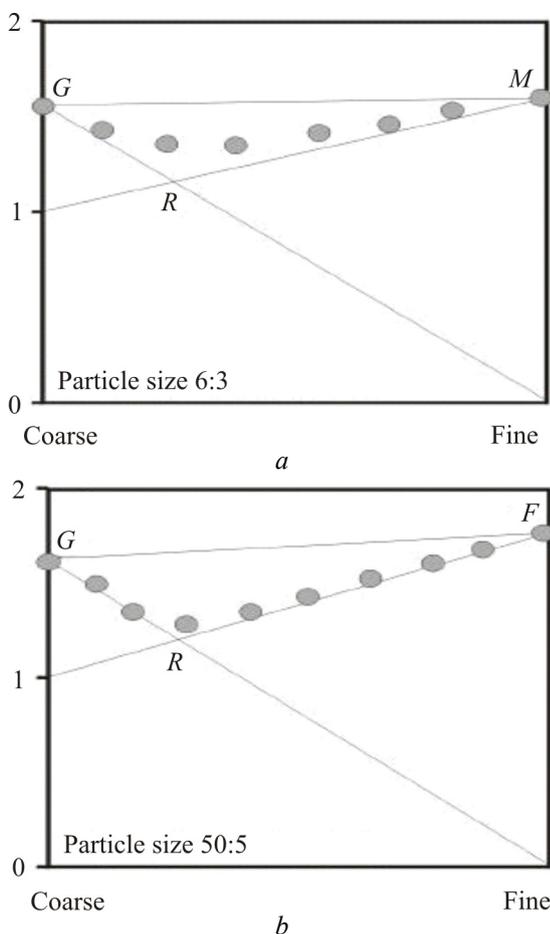
Fig. 7. Simulated influence of a mixture
of particles of different sizes (particle size fractions)
on the porosity of rocks [42]

Of course, real rocks are usually composed of a continuous range of particle sizes, and this leads to a rather complex scenario, where fractal concepts become useful. There are several known examples of the application of fractal theory to the estimation of reservoir properties of oil-bearing rocks [29]; one of such examples is the dependence between fractality and oil saturation. We also tried to calculate average diameters of particles and fractality indices for the abovementioned groups of rocks according to the following formula:

$$\frac{1}{d_{cp}} = \frac{1}{2}\left(\frac{1}{d_{n_1}} + \frac{1}{d_{n_2}}\right).$$

where d_{cp} is the average particle diameter; d_{n_1} is the diameter of n_1 particles; d_{n_2} is the diameter of n_2 particles.

The results of the calculations made (Figure 8) illustrate the influence of the fractality index on the oil saturation with the determined correlation dependence. A rather high correlation coefficient (0,8) of the obtained exponential dependence indicates that the relation between the oil saturation and fractality index is well manifested and credible.

Conclusion

The study of the methods for simulating the multimodal distribution of interparticle porosity and analytical generalization of the particle size distribution analysis data on cores from one of a well-known and long operated oil and gas fields in Azerbaijan revealed the patterns of pore volume densification in productive reservoirs depending on the depth. The correlation between the specific surface area and oil saturation was also determined. The obtained results are based on statistical estimations of the degree of the influence of particular fractions (including prevailing fractions) on the porosity of different types of reservoir rocks.

In particular, in argillaceous-silty sand, increased content of the prevailing fraction (0.175 mm) leads to higher porosity, whereas an increased content of the fraction having a particle size of 0.055 mm reduces the porosity of this group of rocks. In the remaining studied groups of rocks (argillo-arenaceous siltstone, sandy-argillaceous siltstone, and argillaceous sandy loam) the fraction having particle size of 0.055 mm turned out to be prevailing, and the fractions having a particle size of 0.175 and 0.01 mm were present in various quantities. The same way as in the first group of rocks, the coarse-grained fraction (0.25 mm) in this group represented an insignificant amount and was neglected.

$$y = -0{,}0022x^4 - 0{,}0282x^3 + 0{,}1656x^2 + 4{,}2597x + 33{,}281$$
$$R^2 = 0{,}8072$$
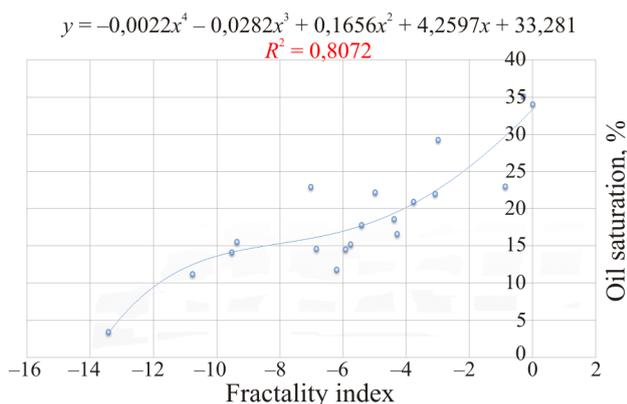
Fig. 8. Dependence of the oil saturation of reservoirs
on the fractality index

The data obtained demonstrate that an increased content of the prevailing particle size fraction and fraction having a particle size of 0.175 mm in argillo-arenaceous siltstone leads to higher porosity, whereas in the group of sandy-argillaceous siltstone the influence of the prevailing particle size fraction (0.055 mm) and a coarser fraction (0.25 mm) on porosity is negative.

In argillaceous sandy loam, the influence of the prevailing particle size fraction (0.055 mm, fine) and the secondary particle size fraction (0.175 mm, coarser) on porosity has the opposite effect in the same way as in the group of argillaceous-silty sand. Thus, an increase in the content of the fine particle size fraction (0.055 mm, prevailing) in argillaceous sandy loam leads to lower porosity, whereas an increase in the coarser particle size fraction (0.175 mm) content increases the porosity.

Moreover, we made several calculations to trace the relationship between the fractality index and oil saturation; as a result, we obtained an exponential dependence showing the relationship between the oil saturation and fractality index.

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