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Experimental evaluation of compressibility coefficients for fractures and intergranular pores of an oil and gas reservoir

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Abstract. The paper is devoted to studies of the volumetric response of rocks caused by changes in their stress state. Changes in the volume of fracture and intergranular components of the pore space based on measurements of the volume of pore fluid extruded from a rock sample with an increase in its all-round compression have been experimentally obtained and analyzed. Determination of the fracture and intergranular porosity components is based on the authors' earlier proposed method of their calculation using the values of longitudinal wave velocity and total porosity. The results of experimental and analytical studies of changes in porosity and its two components (intergranular and fractured) under the action of effective stresses are considered. This approach allowed the authors to estimate the magnitude of the range of changes in the volumetric compressibility of both intergranular pores and fractures in a representative collection of 37 samples of the Vendian-age sand reservoir of the Chayanda field. The method of separate estimation of the compressibility coefficients of fractures and intergranular pores is proposed, their values and dependence on the effective pressure are experimentally obtained. It is determined that the knowledge of the values of fracture and intergranular porosity volumetric compressibility will increase the reliability of estimates of changes in petrophysical parameters of oil and gas reservoirs caused by changes in the stress state during the development of hydrocarbon fields.

***Key words*:** rock; porosity; rock compressibility; pore compressibility; intergranular porosity; fracture porosity; fracture compressibility; hydrocarbon development

Introduction. Development of oil, gas and solid minerals requires consideration of the elastic volumetric response of rocks caused by changes in their stress state [28, 34, 43]. Due to the complex structure of rock pore space, consisting of intergranular pores and fractures [2, 4], changes in the volume of each of the components requires independent consideration and analysis [5, 6]. A relevant task is the analysis and estimation of the magnitude for deformation of intergranular pores and fractures, which arise due to changes in the stress state of the reservoir caused by hydrocarbon production [5, 11, 23]. Thus, work [19] noted the need to take into account the dependence of permeability and porosity properties of pore- and fracture-type reservoirs on changes in the stress state during the development of oil and gas fields. “Compressibility of fractures can differ from compressibility of the matrix by an order of magnitude. For example, in naturally fractured reservoirs in the Kirkuk (Iraq) and Asmari (Iran) fields, fracture compressibility varies between 6-60 GPa^{-1}. At the Groznenskoe field, fracture compressibility varies from 10 to 100 GPa^{-1}. At all these fields the fracture compressibility is 10-100 times higher than the compressibility of the intergranular matrix, and to assume that they are equal is unacceptable practice” [38, p. 514].

Theory of the problem. The volume compressibility coefficient is a parameter that quantifies the relationship between the pressure exerted on a body and the resulting change in its volume. A material without pores or fractures has a single compressibility coefficient, defined by the formula:

$$C = \frac{-1}{V_0}\frac{dV}{dP}, \quad (1)$$

where V_0 – body volume at initial pressure; P – hydrostatic pressure exerted on its outer surface.

There are two independent volumes (sample and pores) and two pressures (universal compression and pore fluid) which can be varied; four different compressibilities can be associated with a porous rock [40, 41]. In each of these compressible porous rocks, changes in either pore volume V_p or rock sample volume V_b are associated with changes in pore pressure P_p or universal pressure P_c. They are described using notations in which the first index indicates the corresponding change in volume and the second index indicates the changing pressure. These compressibility coefficients are most clearly defined in [42]:

• compressibility of the rock volume with changes in universal pressure

$$C_{bc} = \frac{-1}{V_{b0}}\left(\frac{dV_b}{dP_c}\right)_{P_p}; \quad (2)$$

• compressibility of the rock volume with changes in pore pressure

$$C_{bp} = \frac{1}{V_{b0}}\left(\frac{dV_b}{dP_p}\right)_{P_c}; \quad (3)$$

• compressibility of the pore volume with changes in universal pressure

$$C_{pc} = \frac{-1}{V_{p0}}\left(\frac{dV_p}{dP_c}\right)_{P_p}; \quad (4)$$

• compressibility of the pore volume with changes in pore pressure

$$C_{pp} = \frac{1}{V_{p0}}\left(\frac{dV_p}{dP_p}\right)_{P_c}. \quad (5)$$

The concept of effective pressure also needs to be covered

$$P_{\text{ef}} = P_c - \alpha P_p, \quad (6)$$

where P_c – pressure of the universal compression; P_p – pressure of the pore (formation) fluid (water, oil, gas); α – Biot coefficient (sometimes called the unloading coefficient) describes that part of the pore pressure which counteracts the universal pressure.

For rocks with a porosity greater than 5 %, α is often assumed to be 1. In this case, C_{pc} and C_{pp} are equal to each other. In other words, the same changes in the total and pore pressures change the pore volume by the same amount, but with the opposite sign: an increase in the universal compression and a decrease in the pore pressure lead to a decrease in the pore volume.

In order to account for the elastic energy of the entire sample (formation, deposit), the elasticity of both the rock skeleton (solid matrix) and all formation fluids must be taken into account. In this case, the term "total compressibility" [34], or compressibility of the rock (sample) volume, should be used to represent the elasticity of the entire deposit:

$$C_t = \frac{-1}{V_{b0}}\left(\frac{dV_b}{dP_{\text{ef}}}\right). \quad (7)$$

In general, with three phases (oil, water and gas) present simultaneously in the formation, the mathematical expression for the relationship between them and the total compressibility of the rock volume is as follows [34]:

$$C_t = \left(C_{oil}S_{oil} + C_{gas}S_{gas} + C_{water}S_{water}\right)m + C_{sk}, \quad (8)$$

where C_{oil}, C_{gas}, C_{water} и C_{sk} – compressibility of oil, gas, water and solid matrix (skeleton) of the rock, respectively; m – porosity of the rock; S_{oil}, S_{gas}, S_{water} – oil, gas, water content (saturation) in the pore space of the rock, respectively.

During the petrophysical investigations, the pressure and temperature of the pore fluid (formation water model) were maintained at the same level of 13 MPa and 20 °C, only universal pressure was increased (from 15 to 50 MPa). Therefore, the compressibility coefficient of the C_{water} fluid does not need to be taken into account.

Value of the compressibility coefficient for a solid rock matrix can be determined experimentally by means of so-called unjacketed tests [34, 42]. In these tests the rock is pressurised by a fluid (liquid), which penetrates into the pores of the rock, so that the universal pressure and the pore fluid pressure are the same. But unfortunately, the installation used did not permit this kind of test and the compressibility coefficient of the rock mineral matrix was calculated dynamically, based on elastic wave propagation velocity and rock density:

$$C_{sk} = \frac{3}{2}\left[\left(\frac{1}{v_p^2}\right)\left(\frac{1}{v_s^2}\right)\right] / \left[\delta(1+\mu)\left(\frac{1}{v_s^2}-\frac{1}{v_p^2}\right)\right], \quad (9)$$

where C_{sk} – compressibility coefficient of the mineral matrix (skeleton), GPa^{-1}; v_p – longitudinal wave velocity, km/s; v_s – shear wave velocity, km/s; δ – density, g/cm^3; μ – Poisson's ratio (dynamic).

The C_{pc} and C_{pp} compressibilities are pore compressibilities and express the effect of pressure changes on the volume of cavern space contained within the rock. The C_{pp} pore compressibility is used in reservoir analysis because it reflects the volume of excess pore fluid that may be stored in the pore space due to increased pore pressure. This compressibility is added to the compressibility of the formation fluid C_f to represent their sum as the formation compressibility, which is used in the basic formation equation. In this case, pore pressure and universal pressure are assumed to be independent variables; physically, this corresponds to what is known as drained compression (open pore system), in which changes in universal pressure do not cause changes in pore pressure. A closed pore system results in undrained compression with an increase in universal compression, but is not usually a reservoir, as fluid cannot be extracted from these pores without additional action to create additional filtration channels.

Changes in the volumetric deformation of the sample $d\varepsilon_b$ and the volumetric deformation of the pores $d\varepsilon_p$ can be expressed in terms of compressibility of the porous rock:

$$d\varepsilon_b = -C_{bc}dP_c + C_{bp}dP_p; \quad (10)$$

$$d\varepsilon_p = -C_{pc}dP_c + C_{pp}dP_p. \quad (11)$$

Since fluid saturated sandstone can be considered as a homogeneous material, C_{bc} is its effective volumetric compressibility as an analogue of the compressibility of a non-porous material. Another volumetric compressibility C_{bp}, which has been called pseudo-volumetric [25], reflects the effect of pore pressure on the total volume of a rock sample [17]. This compressibility is useful in calculations of land or seabed subsidence in hydrocarbon fields development [12, 20, 25].

When the pore fluid (oil, water, gas) is extracted from the formation (underground deposits), the pressure of the fluid in the pores decreases and the total volume occupied by the deposit (formation) decreases according to equation (7). Subsequent subsidence of the ground surface above the deposit can amount to tens of meters. Subsidence causes significant damage to buildings and other structures. Well-known examples of oilfield subsidence are Wilmington Long Beach in Southern California [29] and Ecofisk in the North Sea [26, 27].

Methodology of the investigation. Experimental investigations were carried out under universal compression growth conditions only, in contrast to ARMA-14-7532 [24], which provides for additional uniaxial compression. The technique used allowed measuring the volume of pore fluid displaced from the sample when increasing the compression and calculating both changes in porosity and estimating the volumetric deformation. This was calculated taking into account that the compressibility coefficient of the solid rock matrix is several orders of magnitude greater than the compressibility coefficient of the pore space.

The porosity under formation simulation conditions was determined (taking into account the volume of fluid displaced from the pore space of the rock sample) using the formula:

$$m = m_{\text{atm}} - \Delta V_p / V, \quad (12)$$

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where m_{atm} – porosity coefficient under atmospheric conditions, %; ΔV_p – volume of pore fluid displaced from the sample (pore volume change), cm^3; V – initial sample volume, cm^3.

The volumetric deformation of the sample, taking into account that the compressibility of the mineral skeleton is two orders of magnitude lower than that of the liquid, was calculated using the formula:

$$\varepsilon = 100\Delta V_p / V. \quad (13)$$

The rock volume compressibility coefficient was determined according to the formula:

$$C_{bc} = C_t = \left(\frac{\Delta V_p}{V}\right) / \Delta P_{ef}, \quad (14)$$

where ΔP_{ef} – changes in effective pressure, GPa.

For the convenience of working with negative numbers of compressibility coefficients, we will consider volume reduction to be positive, which is equivalent to multiplying by –1 the expressions (1), (2) and (4), in which volume increase is assumed to be positive.

The compressibility coefficient of the pore space was determined using the formula:

$$C_{pc} = \left(\frac{\Delta V_p}{V_p}\right) / \Delta P_{ef}. \quad (15)$$

Since $m = V_p/V$, as noted in [34], $C_t = C_{pc}m$. Thus, from formulas (4) and (5) the rock volume compressibility (14) and pore volume compressibility (total porosity) (15) have been determined by changing the effective pressure.

Results. 34 sandy-clay samples of Vendian age were investigated, having under atmospheric conditions porosity coefficient of 3-15.6 %, permeability coefficient of 2-100 mD, made from the rock sample raised from 1660-1860 m depth. The samples are represented mainly by coarse- to fine-grained quartz and quartz-feldspar sandstones with mixed quartz-regeneration, sulphate, clay-film and partly basal cement.

Values of porosity coefficient for rock samples (Fig.1, *a*) from Chayandinskoe oil-gas-condensate field (COGCM) and volume deformation of rock samples (Fig.1, *b*) obtained at current P_{ef} values allowed obtaining their dependence on the growth of effective pressure in the formation in the same way as shown in [1, 8, 23]. Changes of volumetric deformation for samples correspond to changes in porosity caused by growth of P_{ef}.

It is well known that the pore space of rock samples consists of two components: intergranular and fracture space. Fracture porosity is expressed as the ratio of fracture volume to total rock volume:

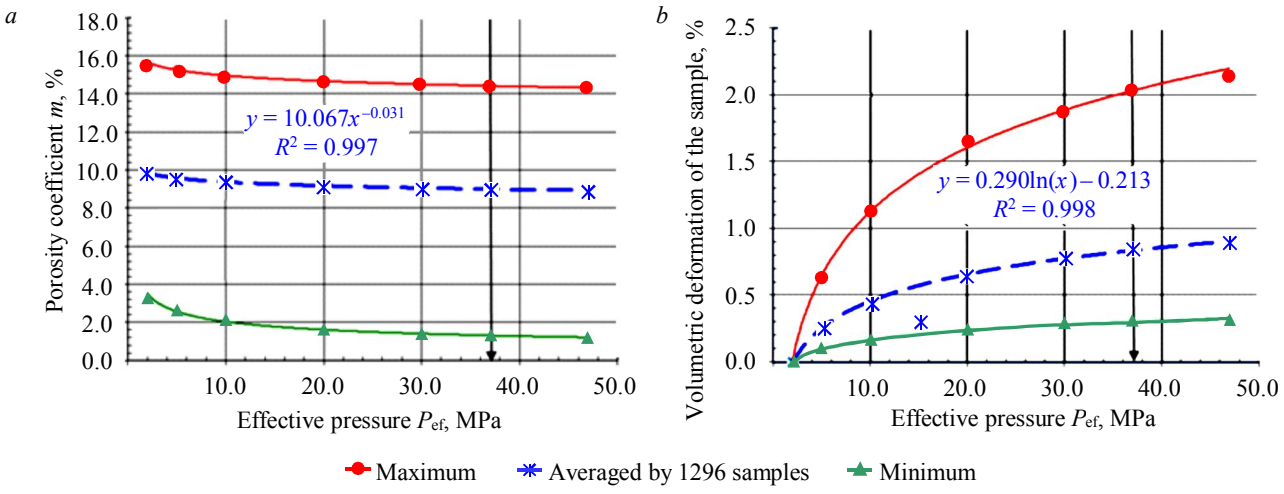


Fig.1. Changes in porosity coefficient (*a*) and volumetric deformation of the sample (*b*) on effective pressure

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$$m_f = 100\, V_f / V. \quad (16)$$

Intergranular porosity is expressed as the ratio of the volume of intergranular space to the total volume of the rock:

$$m_{ig} = 100\, V_{ig} / V. \quad (17)$$

Previously, a method for determining the magnitude of these components has been proposed, based on measuring the value of elastic longitudinal wave propagation velocity [7, 18, 22]. The total porosity and the longitudinal wave velocity were determined at each step of P_{ef}. With increasing universal pressure the pore fluid pressure remained unchanged and hence the P_{ef} increased. The compressibilities of intergranular and fracture porosity and rock volume compressibility coefficients (14), intergranular (16) and fracture (17) porosities, were determined using the expressions:

$$C_{ig} = \left(\Delta V_{ig} / V_{ig}\right) / \Delta P_{ef}; \quad (18)$$

$$C_f = \left(\Delta V_f / V_f\right) / \Delta P_{ef}, \quad (19)$$

where ΔV_{ig} and ΔV_f – changes in the volume of intergranular space and fracture hollowness, respectively.

This technique allowed experimental estimation of fracture and intergranular porosity with P_{ef} increase and separate calculation of compressibility coefficients for sample volume, mineral matrix, fracture, intergranular porosity of rock samples during P_{ef} increase in simulation of hydrocarbon field development process (Table).

Average values of porosity and volumetric compressibility at different values of effective pressure

Coefficients	Effective pressure P_{ef}, MPa					
	2.0	5.0	10.0	20.0	30.0	37.0
Porosity:						
total m, %	9.926	9.681	9.505	9.302	9.163	9.088
intergranular m_{ig}, %	9.178	9.025	8.912	8.783	8.694	8.657
fracture m_f, %	0.749	0.656	0.593	0.519	0.468	0.432
Compressibility:						
Mineral skeleton (dynamic, C_{sk}), GPa^{-1}	0.036	0.033	0.032	0.030	0.030	0.029
rock C_{bc}, GPa^{-1}		0.491	0.422	0.312	0.255	0.227
pore space C_{pc}, GPa^{-1}		5.656	4.705	3.451	2.814	2.501
intergranular pores C_{ig}, GPa^{-1}		3.484	3.009	2.241	1.798	1.563
fracture C_f, GPa^{-1}		25.35	21.30	15.62	12.64	11.62

Discussion. Division of the pore space into hard and soft (pliable) pores has also been considered in [30, 35], where soft pores have been proposed to be identified as fractures. In [37], the PDA (pore deformation approach) proposed by Shapiro [32] is developed where the pore space is divided into hard and pliable parts. Dependencies of porosity and elastic properties on load have a linear contribution due to the hard (intergranular) part and an exponential contribution due to the pliable (fractured) part of the pore space, similar to the one shown in Fig.1.

In fractured samples, both porosity and permeability are drastically reduced when the effective pressure is increased, whereas this is not the case in samples with intergranular porosity [15].

Values of compressibility coefficients for the sample volume, mineral skeleton, volume of the total pore space and separately its intergranular and fracture components for the studied rocks, obtained by increasing P_{ef}, allowed estimating their values at different pressures [2, 13, 14], and also revealing their empirical dependences on P_{ef}, similar to those given in papers [31, 33, 36]. The obtained dependencies with high reliability ($R^2 = 0.99$) can be approximated by the logarithmic equations

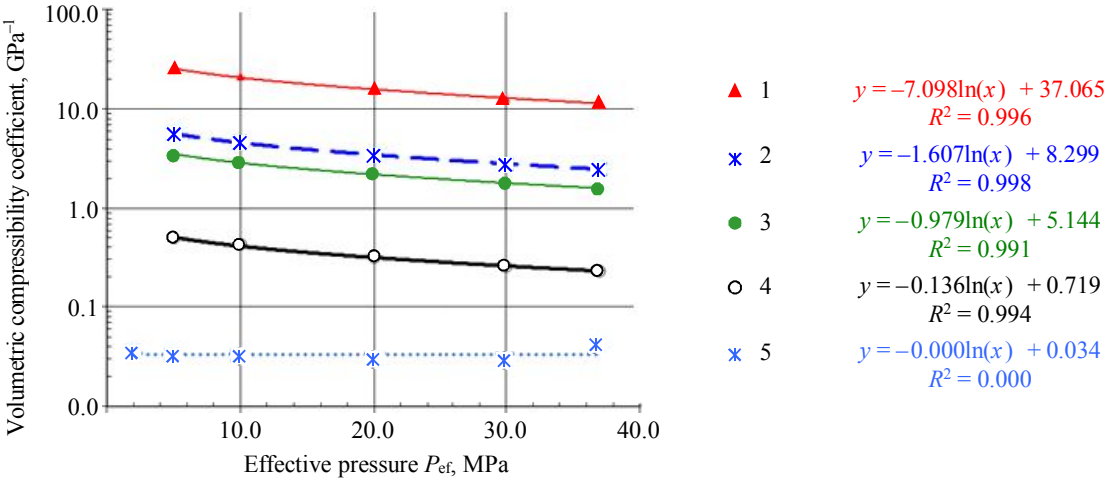


Fig.2. Variation of volumetric compressibility coefficients: mineral skeleton, rock, total pore space and its two components (intergranular and fracture) on the effective pressure

1 – fractures (equation (19); 2 – total porosity (equation (15); 3 – intergranular pores (equation (18); 4 – rock (formula (14); 5 – mineral skeleton (equation (9)

(Fig.2), at that, the highest values of compressibility coefficient are characteristic for fractures, and the lowest ones – for intergranular porosity.

For a more accurate assessment of surface subsidence in the process of field development on the depletion, the ratio of the values for the compressibility coefficients of the fracture and intergranular components of porosity to the total compressibility of the sample volume with the growth of P_{ef} is important. Results of experimental investigations have shown that the ratio of compressibility coefficients of fracture and intergranular pores keeps approximately at the same level (on the average 7.85-8.40), which varies for different samples in the range 26.9-2.46, that is the change of fracture volume on the average almost eight times more than the change of intergranular pores volume at that same value of P_{ef}. Value of the compressibility coefficient of the total pore space enters into the range of values for the compressibility coefficients of fracture and intergranular porosity components and is determined by the share of fracture porosity in total porosity.

Average value for the ratio of fracture compressibility coefficients to rock compressibility with increase of P_{ef} changes in a narrow range 54.0-55.3, which varies for different samples in the range 19.6-105.0. This indicates that when P_{ef} changes by the same value, the relative change in fracture volume is almost 55 times greater than the relative change in the volume of the total sample.

In 1965 J.B.Walsh has revealed that at a certain concentration of narrow fractures their influence on rock compressibility is similar to the influence of the same number of spherical pores with diameter of two thirds of fracture length, but the fracture porosity at that is much less than porosity caused by spherical pores; the longer a fracture in the rock, the greater its compressibility. The rapid decrease in fracture compressibility at the initial stage of increasing P_{ef} can be explained by the closure of a small number of existing long fractures.

Determination of fracture and intergranular porosity values of the studied rocks allowed estimating changes in the value of the compressibility coefficient for the entire pore space depending on the share of fracture m_f/m and intergranular m_{ig}/m porosity when P_{ef} grows from 2.0 to 37.0 MPa. It was found that the compressibility coefficient of the pore space also increases with increasing share of fracture porosity (Fig.3, *a*). At the same time, the increase of intergranular porosity share decreases the compressibility coefficient of pore space (Fig.3, *b*), because the compressibility coefficient of fractures is significantly higher than the compressibility coefficient of intergranular pores.

Previously, the authors [5, 6, 39] revealed that with the growth of P_{ef}, the share of fracture porosity decreases and its influence reduces. Works [3, 4, 10, 16] note the necessity to take into account compressibility of reservoirs during development of fields and dependence of filtration zone radius

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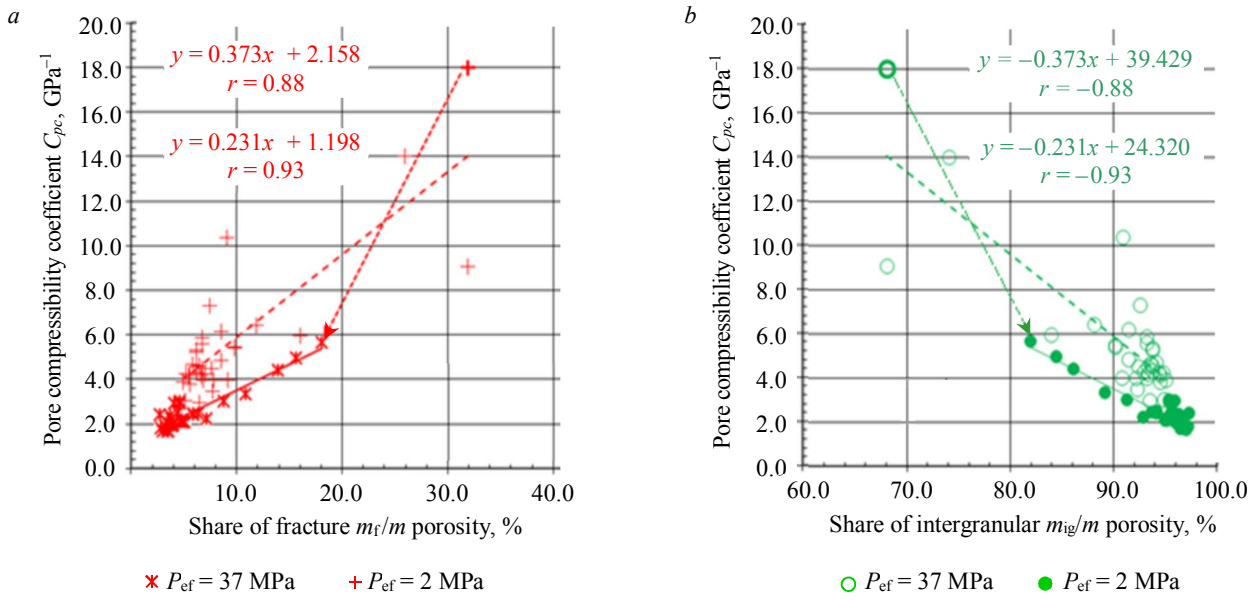


Fig.3. Effect of fracture (*a*) and intergranular porosity (*b*) on the compressibility coefficient of the entire pore space at effective pressures of 2.0 and 37.0 MPa; $n = 34$. The arrows show the changes in of parameters at transition of effective pressure from 2.0 to 37.0 MPa

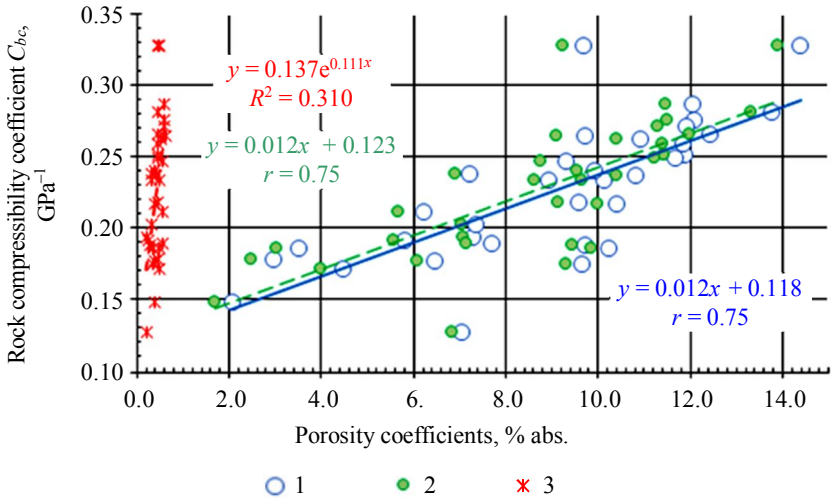


Fig.4. Influence of total (*m*) porosity and its two components (intergranular m_{ig} and fracture m_f) on compressibility coefficient of rock at an effective pressure of 37 MPa

1 – total porosity, $n = 34$; 2 – intergranular porosity; 3 – fracture porosity

in the developed formations on the compressibility coefficient of the reservoir. Therefore, determining the compressibility coefficient of fractures and knowledge on the value of fracture porosity will allow reliable prediction of the possible changes in oil and gas reservoirs in the process of changing the stress state of productive formations with fractures in the development of the fields.

It is known that the formation of land surface subsidence occurs most often due to the reduction in thickness of productive rocks during field development, and it is important to determine which components of the rock compressibility coefficient have a stronger influence on it. Experimental data showed that the main contribution to the value of rock compressibility coefficient is made by the value of total porosity and its intergranular component (Fig.4). But changes in fracture porosity have

greater (0.238/0.012 = 19.8) influence on rock compressibility coefficient than the same changes in intergranular porosity.

Experimental results have shown (see table) that total porosity and both its components decrease as P_{ef} grows, but at different rates: fracture porosity decreases faster. The compressibility coefficients also decrease at different rates as P_{ef} increases.

Conclusion. The method of separate estimation of compressibility coefficients for fractures and intergranular pores has been proposed, their values and dependence on effective pressure have been experimentally obtained. The results have shown that the highest values of the compressibility coefficient are characteristic for fractures, and the lowest – for intergranular porosity. It is shown that the compressibility coefficient of fracture volume on average is almost eight times greater than the compressibility coefficient of intergranular porosity volume and almost 55 times greater than the compressibility coefficient of the investigated rocks volume. A higher compressibility of the entire pore volume of rocks with a high share of fractured porosity can be expected due to the fact that fractures have a higher compressibility coefficient.

Thus, the determination of fracture and intergranular porosity compressibility coefficients will improve the reliability of estimates for changes in petrophysical parameters of oil and gas reservoirs caused by changes in stress state during production. The results of the research can be used to account for changes in physical properties of reservoirs and to refine the value of subsidence during oil and gas field development.

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