REVIEW ARTICLE

DOI: https://doi.org/10.18599/grs.2020.4.55-69 Russian Original 2020. Vol. 22. Is. 4. Pp. 55–69

Investigation of the scale effect and the concept of a representative volume element of rocks in relation to porosity

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Abstract. The article discusses the concepts of upscaling, the representative volume element (RVE) of the geological environment in relation to porosity from the point of view of the theory of structured continuum. The manifestation of the large-scale effect of porosity in terrigenous and carbonate reservoirs has been studied. The analysis of domestic and foreign methods of core sampling was carried out using the example of the Schlumberger company to study the porosity and permeability of the core in petrophysical laboratories and calculate the RVE of rock samples according to the porosity values determined by analyzing the pore-network model, liquid saturation, nuclear magnetic resonance and X-ray computed tomography, as well as the gas-volumetric method. The features and reasons for the manifestation of the large-scale effect of porosity in heterogeneous carbonate reservoirs have been studied. Methods for quantitative assessment of the anisotropy of rocks in the study of heterogeneity of rocks are considered. The necessity of taking into account the scale effect of porosity in the analysis of the correlation dependence "core – geophysical well logging", established from the porosity data for both terrigenous and carbonate sections. The feasibility of using a core with a diameter of 60–100 mm and standard-size samples is considered when comparing laboratory values of porosity and porosity values determined from logging data. A study of direct and indirect petrophysical methods for determining the porosity of core samples was carried out when solving the same problems to identify the minimum representative volume of a core sample. It has been established that direct methods are the most effective in terms of time and financial costs for the prompt calculation of porosity coefficients for specimens with a diameter and height of 30–100 mm. The analysis of the porosity data ultimately made it possible to study the manifestation of the scale effect of porosity with a change in the sample size. A detailed analysis of published works will allow in the future to develop our own effective sampling technique for determining the RVE of the core interval as applied to porosity.

Key words: representative volume element, representative elementary volume, core, open porosity coefficient, scale effect of porosity, liquid saturation method, upscaling, downscaling, pore-network model, standard core analysis, X-ray computed tomography

Recommended citation: Khassanov D.I., Lonshakov M.A. (2020). Investigation of the scale effect and the concept of a representative volume element of rocks in relation to porosity. *Georesursy = Georesources*, 22(4), pp. 55–69. DOI: https://doi.org/10.18599/grs.2020.4.55-69

Introduction

Depending on the size of the core samples studied in the laboratory, different values of the open porosity factor can be obtained for the same reservoir. This phenomenon is called the scale effect (Shashenko et al., 2004), which is closely related to the concept of an representative elementary volume (Tomin, 2011). For the first time in Russian science, the concept of a scale effect for rocks was introduced by M.I. Koifman (Koifman, 1963), who argued that the scale effect is the dependence of the mechanical properties of rock samples on their linear dimensions. This concept is used in scientific works mainly in the study of the mechanical properties of rocks, however, individual researchers consider the large-scale effect when analyzing the porosity of rocks, in other words, they study fluctuations in the porosity of a core sample with a change in its linear size (Putilov et al., 2019; Gurbatova, Kostin, 2010). The large-scale effect of porosity has a significant impact on the accuracy of calculating oil reserves by the volumetric method in Russian petrophysical laboratories (Zhdanov, 1970) and calculating the initial geological reserves of stock tank oil (STOIIP) in laboratories in the UK and USA (Dake, 1994).

The open porosity factor included in the formula for calculating oil reserves by the volumetric method is in most cases determined using core samples of standard size (3 cm high and 3 cm in diameter) according to

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(State standart 26450.0-85, 1985), which in the case of studying heterogeneous rocks may be unrepresentative. Thus, neglecting of the scale effect can lead to inaccurate determination of the open porosity factor of core samples and, as a consequence, to incorrect establishment of the correlation relationship "core – geophysical logging (GL)".

The purpose of this work was to study the concept of an representative elementary volume (REV), the scale effect in relation to porosity, upscaling, and to consider the methods for determining the REV of a core from porosity data established by various petrophysical methods.

The article presents an analysis of publications by foreign authors (J. Bear, L.P. Dake, and others) and the works of domestic researchers (B.I. Prilous, I.P. Gurbatova), devoted to the methods of core sampling for determining their porosity in laboratory conditions, calculating REV when studying the pore volume of reservoirs, comparing the values of porosity established from the core and from well logging data.

Literature overview

In foreign petrophysical laboratories, when conducting a routine core analysis (RCA) in order to assess the porosity of reservoirs, special attention is paid at the preparatory stage to the choice of the size of the studied core sample (Andersen et al., 2013). In the simplest case, when determining the porosity of a homogeneous reservoir, from individual fragments of a full-size core (1 m long), every 25 cm (30 cm), cylindrical samples are drilled and made with a length of 5.08–7.62 cm (2–3 inches) and a diameter of 2.54 cm (1 inch) or 3.81 cm (1.5 inches) (Glover, 2001). In particular, Schlumberger uses samples with a height of 6.4 cm and a diameter of 2.54 cm or 3.8 cm for research (Andersen et al., 2013). When studying the porosity of heterogeneous reservoirs, for which the Dykstra-Parsons coefficient varies in the range 0.25–0.5 (Tiab, Donaldson, 2012), the interval for sampling cylindrical samples from fragments of a full-size core with a length of 3 feet can be reduced (Andersen et al., 2013). When considering reservoirs with a Dykstra-Parsons coefficient of 0.5 to 0.75, cores of initial diameter up to 15 cm (6 in.) long and 4.4–13.3 cm (1.75–5.25 in.) in diameter are used for standard analysis (API RP 40. Recommended Practices for Core Analysis. 1998; Oilfield Glossary. https://glossary.oilfield.slb.com/en/Terms/w/whole_core.aspx).

In Russian petrophysical laboratories, core samples are taken to determine the porosity of reservoirs in accordance with the requirements presented in (Goroyan, 1978; State standart 26450.0-85, 1985). Optimal for determining the values of the open porosity factorof homogeneous reservoirs are cylindrical samples 3 cm long and 3 cm high, drilled from core intervals every 25–30 cm. To study reservoirs with a complex pore space structure, by analogy with the foreign approach, samples with a diameter of 60–90 mm are used (keeping the original diameter of the core interval).

However, when considering rocks of different lithotypes that make up the productive horizon, it should be borne in mind that the internal structure of each rock can vary significantly within the volume of the productive reservoir, for example, the clay content and carbonate content of sandstones at a relatively small depth interval can vary over a wide range (Types of structural heterogeneity oil deposits and their quantification. http://www.geokniga.org/bookfiles/geokniga-1_0.pdf). It is obvious that the analysis of samples with a diameter of 60–90 mm is a universal way to obtain representative values of the porosity of a carbonate or terrigenous reservoir. However, to determine the porosity of the core interval of a given length, it is necessary to take a large amount of core with a diameter of 60–90 mm. The use of such samples requires a larger volume of the extracting liquid, therefore, the task of determining reliable values of the porosity of a core interval of a given length using a single (whole) core sample of the minimum volume is urgent.

In the course of the analysis of published scientific works, it was found that the consideration of the concept of an representative elementary volume of a rock in relation to porosity includes the formulation of the definition of this term and a practical calculation of the representative volume of the core.

The concept of scale effect and upscaling

The scale effect in some works is often replaced by terms such as upscaling and downscaling. In the work (K.-A. Lie, 2019), the features of constructing a hydrodynamic model of an oil reservoir are considered, for the creation of which it is necessary to build a geological model based on the data of interpretation of seismic exploration, directional survey, and well logging. After the analysis of the initial data, structural 3D modeling is performed – the creation of a set of structural base surfaces, and the roofs of productive strata in three-dimensional space, and the setting of a three-dimensional mesh – the division of the space between the top and the bottom of the reservoir into three-dimensional cells. Further, lithological-facies and petrophysical modeling, as well as saturation modeling are carried out. Lithological-facies modeling refers to the assignment of indices to cells depending on a specific lithotype and a particular facies, while petrophysical modeling refers to the determination of porosity and permeability values in each cell of a three-dimensional grid (Putilov, 2011). Then a hydrodynamic model is built in several stages (Aziz, 2014); the transition between the two models is accompanied by the rescaling procedure – the selection of the optimal cell size. The main criteria when choosing a size are speed and accuracy of calculations. With a larger cell size, the accuracy of the model construction decreases, but the calculation speed increases (Kaigorodov, 2018). The geological model may contain such a number of cells that is not acceptable for building a hydrodynamic model due to an increase in the calculation time, therefore, a necessary step is to reduce the number of small cells of the geological model by combining them in order to obtain larger cells of the hydrodynamic model. Obviously, the spatial resolution decreases in this case (Petrov et al., 2015). The process of setting equivalent reservoir and geomechanical parameters for a hydrodynamic model when moving from a higher resolution model to a lower resolution model is called upscaling (K.-A. Lie, 2019). The difference between the reservoir parameters of the initial and the enlarged grids of the hydrodynamic model should be minimal.

The process of establishing equivalent reservoir and geomechanical parameters when moving from a model with a lower resolution to a model with a higher resolution is called downscaling, respectively. In practice, it is periodically necessary to adjust the hydrodynamic model of an oil reservoir according to the development history data to obtain an initial geological model with refined parameters. In this case, downscaling is used, the main purpose of which is to preserve the features of both macro-heterogeneity and micro-heterogeneity (K.-A. Lie, 2019).

Thus, based on the results of the analysis of a number of articles, it can be concluded that the scale effect of porosity consists in the manifestation of possible variations in porosity values with a change in the volumes of the studied rock, while the concepts of upscaling and downscaling denote procedures for establishing equivalent values of porosity (and permeability) during the transition from one model (geological) with a given resolution to another model (hydrodynamic) with a resolution different from the first one.

Theoretical consideration of an representative elementary volume

Presumably, for the first time, the concept of a representative volume in exact sciences was introduced by Hendrik Anton Lorentz in his work on the theory of electrons (Lorentz, Teubner, 1916). In geological sciences, the concept of a representative volume in relation to the additive properties of rocks (porosity and density) was refined by J. Bear, B.I. Prilous, P.V. Moskalev and V.V. Shitov. J. Bear in (Bear, 1972) and B.I. Prilous in (Prilous, 2013) considered the concept of REV of the geological environment for additive properties from the standpoint of the theory of continuum associated with the dynamics of fluids in the pore space. The object of study in the theory of continuum is a porous medium (rock), which J. Bear investigated at the microscale and macroscale, noting changes in physical properties (porosity of the medium and fluid density) depending on the scale of the study. B.I. Prilous, as a result of a critical analysis of a number of works, found that the study of the medium under consideration in order to determine its representative volume in relation to additive properties must be carried out at the mesoscale (Figure 1).

Limiting the studied porous medium to a region that is a sphere of volume ΔU_i, the center of which is located at some arbitrary point P, the scientists investigated the fluctuation of the porosity coefficient of the medium n_i with a change in the radius of the spherical region to determine the minimum representative volume.

The porosity coefficient n_i in this case is:

$$n_i = n_i(\Delta U_i) = (\Delta U_v)_i/\Delta U_i, \quad (1)$$

where the volume of the pore space is designated as (ΔU_v) i (void space – pore volume). The values of the porosity coefficient are calculated at i = 1,2,3 ..., an increase in the index i in this case means a sequential decrease in the volume of the porous medium (hence, the volume of the sphere) from the maximum initial volume of the sphere ΔU1 to the volume at point P equal to zero (Figure 2).

A similar graph is also presented in (Bear, 1972). It should be noted that J. Bear considered the concept of a representative rock volume for porosity using the scale classification proposed in (Tiab, Donaldson, 2012), according to which the macroscale is intermediate between the microscale and the mesoscale.

Determination of porosity at the micro level occurs when studying petrographic thin sections, the calculation of porosity at the mesoscale is when analyzing logging data, respectively, porosity at the macro level is determined by laboratory methods. The representative elementary volume established by J. Bear in relation to additive properties is the boundary volume between the area of manifestation of microheterogeneity and macroheterogeneity. The concept of a representative volume is associated with a macroscale. Similar reasoning was used by B.I. Prilous, however, to study the representative volume, another classification of scales was used, according to which the macroscale is larger relative to the mesoscale, that is, the mesoscale in the work of B.I. Prilous is equated to the macroscale presented in the classification of J. Tiab (Tiab, Donaldson, 2012). As a result of the interpretation of the graph (Figure 2), the following conclusions were made:

1) at $\Delta U_i = 0$, the sphere decreases to point P, therefore, the porosity coefficient takes on a value equal to 1 if point P is inside the pore, or zero if point P is in the mineral skeleton;

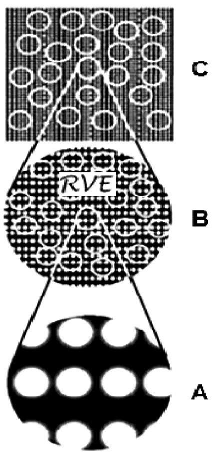

Fig. 1. Hierarchy of scales of a heterogeneous environment: A – microscale, B – mesoscale, C – macroscale (Bear, 1972)

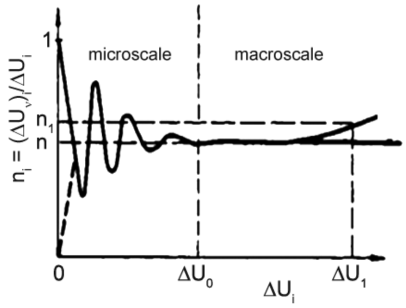

Fig. 2. Determination of the representative elementary volume from the graph of the dependence of the porosity coefficient on the volume of the porous medium (Bear, 1972)

2) at $0 < \Delta U_i < \Delta U_0$ in the region of manifestation of microscopic inhomogeneity, fluctuations of porosity are large and significant due to the coincidence of the sizes of the decreasing sphere with the sizes of individual pores.

The fluctuation amplitude gradually decreases when approaching the volume ΔU_0, at which changes in the values of the porosity coefficient become insignificant (minimal). Thus, the volume ΔU_0 is the minimum (elementary) representative volume of a porous medium, established in relation to porosity (REV (RVE) – representative elementary volume (representative volume element)). The concepts "representative elementary volume" and "representative volume element" used in the article are equivalent.

It should be noted that the coefficient of porosity n of a homogeneous porous medium in the interval $\Delta U_0 < \Delta U_i < \Delta U_1$ remains constant. In the case of a heterogeneous porous medium, the value of the porosity coefficient is unchanged only in a certain part of the interval $\Delta U_0 < \Delta U_i < \Delta U_1$, for example, at $\Delta U_0 < \Delta U_i < \Delta U_c$, where ΔU_c should be understood as the maximum representative volume within the entire considered segment. Further, at $\Delta U_c \rightarrow \Delta U_1$, a fluctuation of the porosity coefficient appears.

Thus, within the framework of the continuum theory as applied to porosity, the representative volume element (representative elementary volume) of the rock should be understood as the volume of the sample, which is transitional between the regions of macroheterogeneity and microheterogeneity, within which the distribution of cracks, pores is statistically significant, and the representative physical property of the medium (porosity) does not undergo significant changes when additional cracks, pores are included in this volume. The representative volume of rock samples in relation to porosity is determined by two conditions (in addition to its definition presented above):

1) REV should be larger than the volume of a single pore, that is, include a certain number of pores to obtain the set of statistical data required within the framework of the continuum theory;

2) REV should be much less than the total volume of pore channels through which fluid filtration is possible.

The presented approach for determining the REV of rock samples in relation to additive properties is used in many practical works. In works (Tomin, 2011; K.-A. Lie, 2019) by analogy with J. Bear and B.I. Prilous is considered the issue of choosing the optimal volume of core material for reliable values of porosity determination used as input data in modeling oil fields. The optimal volume of a core sample in relation to additive properties is an representative elementary volume – the minimum volume of a porous medium at which fluctuations in the values of additive properties (porosity) are minimal (insignificant), that is, practically absent.

The petrophysical parameters in each cell of the geological model are established by transferring the porosity values of the core samples, as a result of which the scale up procedure takes place, which is correct only under a certain condition. REV acts as a criterion of reliability.

Thus, to carry out the correct scale up procedure, it is necessary to determine the porosity values of representative core samples with subsequent transfer of the obtained values to the grid cells. Analysis of samples whose volume is less than REV leads to the determination of unreliable values of additive properties (porosity), which causes difficulties in establishing porosity values in each cell of the geological model (Tomin, 2011). Therefore, laboratory analysis of the core in order to establish the petrophysical parameter (porosity) must necessarily be accompanied by the establishment of the REV of the studied core fragment (for example, the core interval 1 m long) and the determination of the exact values of the porosity of a representative sample.

In (Moskalev, Shitov, 2007), a phenomenological approach is used to consider and simulate a porous medium, which consists in using macroparameters of additive properties (porosity), which describe the properties of the medium as a whole (Golubev, Mikhailov, 2011). The use of the theory of continuity to consider the transport problem has led to the problem of choosing a representative volume of a porous medium. P.V. Moskalev and V.V. Shitov found that the REV for additive properties should be *"small enough in comparison with the dimensions of the porous body to provide an acceptable error when approximating the differential volume of a fictitious continuous medium"*, but at the same time *"large enough to provide the* *same macroscopic characteristics when averaged that the porous medium as a whole with a given level of confidence probability"* (Moskalev, Shitov, 2007).

The REV of the core (in relation to additive properties) can be determined from the porosity data established by:

1) by the method of nuclear magnetic resonance;

2) by X-ray computed tomography;

3) when building a stochastic porous-network model of a core sample to assess porosity and permeability;

3) in laboratory conditions by the gas-volumetric method, as well as by the liquid saturation method.

It should be noted that additional studies of such a non-additive property as the permeability of samples of different sizes, presented in separate publications, are carried out on the basis of the porosity of samples in order to establish the reasons for the manifestation of the scale effect and study the heterogeneity in cores with a diameter of 60–100 mm. In this article, the main physical parameter studied is porosity, while the demonstration of the conclusions related to permeability is necessary exclusively to characterize the structure of the pore space of the considered samples of different sizes. For this reason, the study of REV in relation to non-additive properties is not presented.

Determination of the effective porosity of core samples by nuclear magnetic resonance.

The study of the scale effect in rocks is possible using the method of nuclear magnetic resonance (NMR). NMR occurs as a result of the simultaneous action of a strong magnetic field and an alternating electromagnetic field of the radio frequency range perpendicular to it on a core sample under study saturated with formation water or hydrocarbons. Both fluids contain hydrogen nuclei (protons), each proton has spin and magnetic moments. When a proton is introduced into an external magnetic field, its energy will depend on the direction of the magnetic moment (in the direction of the field action or against). Obviously, the investigated core sample contains a large number of protons, which can be conditionally divided into two equal (under certain assumptions) groups: protons with spins directed "up" and protons with spins directed "down". As a result of the action of an alternating electromagnetic field on the sample, numerous changes in the directions of the magnetic moments will occur, with further ordering of the proton spins in the direction opposite to the action of the magnetic field. The change in the orientation of a large number of protons occurs in parallel with the intense absorption of quanta of the alternating electromagnetic field. This process of absorption of quanta is called nuclear magnetic resonance (Ivanov et al., 2008; Kostin et al., 2014).

In petrophysical studies of a core sample by the NMR method, the final measurement result is presented in the form of an NMR signal distribution with a change in the transverse relaxation time T_2. From the point of view of the physical meaning, such a dependence is the differential distribution of porosity depending on the transverse relaxation time T_2 (Kostin et al., 2014). Transverse relaxation should be understood as the transfer of energy from one nucleus to neighboring nuclei of the same kind due to spin exchange (Koldin, 2003). This parameter is key in the interpretation of nuclear magnetic logging data (hence, the NMR core method) using the standard cutoff method, the essence of which is to establish the type of water (capillary-bound, bound) for each lithological type of rock (Table 1) (Kostin et al., 2014).

Modern mobile units allow examining large-diameter samples (no more than 106 mm) and whole core intervals up to 1 m long, that is, determining the REV of a core sample from porosity fluctuation data is a real task. The advantages of the NMR method are:

1) good convergence between the values of the porosity of core samples obtained by the method of liquid saturation (State standart 26450.1-85, 1985) and the data established by the results of NMR studies of the samples;

2) the possibility of studying the non-extracted core interval directly in the well after its extraction for a short period of time (Kostin et al., 2014; Fattakhov et al., 2016; Kirgizov, 2018).

The main disadvantages of the NMR method are:

1) high cost of NMR spectrometers and mobile units;

2) the impossibility of accurately determining the porosity of the core sample in the absence of fluid in the void space.

In the case of considering the extracted core fragment, saturation is performed with a liquid, for example,

Facies	Reed face travertine			Flat pool travertine		
Length, cm	15	4	1.5	15	4	1.5
Dimeter, cm	10	2	0.7	10	2	0.7
Voxel volume, μm^3	18×10^7	12	4	18×10^7	12	4
Average pore volume, mm^2	108.7	–	–	35.5	–	–
Porosity factor, %	5.9	12.9	–	–	4.44	5.42
Representative elementary representative volume, mm^3	23800	>150	–	1230	1.14	0.074

Table 1. The results of determining the average pore volume, porosity coefficient, REV (Claes, 2012)

with a model of formation water with a certain salt concentration (Fattakhov et al., 2016).

It should be noted that when studying a core sample by NMR, effective porosity is determined – porosity, which includes only pores saturated with fluid. It is obvious that the effective porosity does not take into account subcapillary pores, since there is no movement (penetration) of liquid in them, however, this drawback is also characteristic of the liquid saturation method (State standart 26450.1-85, 1985).

Determination of porosity of rocks by X-ray computed tomography

One of the most widespread methods for studying REV of rocks (in relation to additive properties) is X-ray computed tomography (X-ray CT).

X-ray tomography is a method of layer-by-layer study of rock samples characterized by an inhomogeneous structure of the pore space, in X-ray radiation using special devices – tomographs. Any X-ray tomograph contains: 1) a source (X-ray tube); 2) detector (matrix); 3) core holder. During scanning, the source and the detector (or the source and the sample, the detector and the sample) are rotated in one plane in order to obtain a clear image of a specific area (Ivanov et al., 2008).

The method is based on the phenomenon of X-ray radiation attenuation depending on changes in the density and atomic composition of substances. As a result of obtaining a large number of X-ray images of an object and processing them using special software methods, volumetric images are formed (Savitskii, 2015).

Compared to liquid saturation and helium porosimetry, X-ray CT makes it possible to study the structural features of rocks at the microscale (at the level of the smallest pores), mesoscale and macroscale (at the level of cores with a diameter of 60–90 mm) (Kaufhold et al., 2016). The use of X-ray CT to determine the porosity of samples of different sizes (smaller than a standard sample with a diameter and height of 3 cm) is accompanied by the use of various measurement techniques.

In (Claes, 2012), an effective technique for studying the issue of REV is presented using the example of samples with a varying ratio of length and diameter, which are studied on X-ray computed tomographs with different resolution. Two parallelepiped-shaped samples 2 m long, 3 m wide and 2 m high were chosen as the rocks under study. The first sample is reed face travertine, the second sample is flat pool travertine. At the first stage of the work, three arbitrary mutually perpendicular faces of each parallelepiped (indicated in the article as upper, front and back) are selected. On each face inside the marked square area with an edge length of 1 m, square areas with edge lengths of 0.75 m, 0.5 m, 0.25 m are additionally located inside each other. On all faces, for each square area, the surface porosity was determined by photogrammetry. For samples of both facies, graphs of fluctuations of surface porosity with a change in the size of a specific square area were plotted, considering in aggregate three faces of the sample. According to the plotted graphs, for each parallelepiped, an elementary representative area of the face was determined, equal to 0.5625 m^2 for reed facies travertine and 0.0625 m^2 for horizontally layered travertine. Further, cylindrical samples 15 cm long and 10 cm in diameter were drilled from each parallelepiped in three mutually perpendicular directions. Sequentially smaller samples were taken from large samples, then each sample was examined by X-ray CT at a specific voxel volume (three-dimensional pixel) depending on the sample size. The dimensions and physical parameters of the samples under study are given in Table 1.

Based on the results of measurements, the following was established:

1) the structure of the pore space in samples 15 cm long and 10 cm in diameter is completely different from the structure of the pore space in samples 4 cm long and 2 cm in diameter;

2) the size of the REV sample in relation to porosity depends on the lithotype of the rock;

3) reliable values of porosity of samples of carbonate rocks by the X-ray CT method can be determined by studying samples with a changing ratio of length and diameter on X-ray tomographs with different resolution.

It should be noted that in this work, instead of the concept of a scale effect, the concept of upscaling is used, which is explained by the similarity of this research algorithm with the method for constructing a hydrodynamic model.

In (Al-Raoush, Papadopoulos, 2010; Zakirov et al., 2015), the authors compared the REV of the sample, determined from the graph of fluctuations of the porosity coefficient values (Bear, 1972), with the representative volume of the same sample, calculated from the graphs of fluctuations of other significant characteristics rocks. The studied samples in (Al-Raoush, Papadopoulos, 2010) were samples of different sands characterized by the following dimensions of mineral grains: 1.4–1.7 mm (S1), 1.0–1.2 mm (S2), 0.4–0.6 mm (S3), 0.4–1.7 mm (S4). In the article (Zakirov et al., 2015), the sandstones of the Carboniferous and Permian age of the Ashalchinsky deposit are considered. The four sand samples presented in the article were previously placed in special cylindrical containers made of organic glass (Perspex tubes) 10 mm high and 24 mm in diameter to obtain 3D images of the samples in the form of a cylinder. Based on the results of the study of the samples by the X-ray CT method (with a voxel volume of 64000 μm^3), a 3D image was obtained for each sample, which determined:

1) the coefficient of open porosity (the ratio of the volume of the pore space, calculated from the 3D image, to the total volume of the image);

2) the distribution of coordination numbers (the number of particles in contact with the considered particle; all particles in the sample are sequentially selected as the considered particle);

3) distribution of particle sizes (particle diameters);

4) the distribution of local void ratio.

The local porosity coefficient should be understood as the ratio of the pore space between mineral grains to the total volume of these particles in a limited spatial area. The selection of the region of minimum volume, including at least two particles, occurs with respect to an arbitrary considered particle. This procedure is repeated for all particles in the sample.

The determination of the values of the representative volume by fluctuations of different parameters for each sample was made by constructing:

1) a diagram of the open porosity factor versus the ratio of the volume of the 3D image to the volume of a sphere with a diameter of $10^4 \times D_{50}$, where D_{50} is the diameter at which 50% of the particles (by mass) have a smaller diameter compared to D_{50};

2) three total integral curves of distributions of coordination numbers, particle sizes and local porosity coefficients. Each of the three curves is represented by a graph, the ordinate of which is the total content of fractions in fractions of a unit, that is, the percentage of the next one is added to the percentage of the previous fraction, etc. Each point of any of the three curves indicates the total number of particles both with a specific parameter (for example, with the value of the local porosity coefficient, conventionally equal to X), and with smaller parameters (with the values of the local porosity coefficient, which are less than X). For each sample, a tendency has been established: the values of the minimum representative volume, calculated from the graphs of fluctuations of three parameters, are greater than the REV, determined from the diagram of fluctuations of the open porosity factor.

The representative volumes of three samples of Permian and Carboniferous sandstones of the Ashalchinskoye field in the form of a parallelepiped measuring 10×4×4 mm, taken from a core 1 m long, were determined by studying fluctuations in porosity, specific pore surface area, components of the absolute permeability tensor (Zakirov et al., 2015). The authors found that in order to accurately determine the minimum representative volume of the sample, studies should be carried out not only of porosity, but also other significant characteristics of porous media. The parameters of the physical properties of the samples were determined by the X-ray CT method with a uniform increase in the number of voxels in the image, in other words, with an increase in the image resolution. The representative volume of each sample is established from the graphs of the dependence of the porosity coefficient/specific pore surface area/components of the absolute permeability tensor on the image size in voxels. The REV values obtained from the graphs of fluctuations of the three parameters for each sample significantly differ from each other.

Based on the results of the interpretation of the plotted plots in (Al-Raoush, Papadopoulos, 2010; Zakirov et al., 2015), it was established that an accurate determination of the minimum representative volume of a core sample is possible only when analyzing several main characteristics of porous media.

In the works (Abrosimov, 2017; Sun et al., 2019), the determination of the porosity of rocks was carried out by the X-ray CT method using a new approach, which consists in the selection of relatively small microsamples (virtual cubes) from different parts of the core model. The main advantage of this technique is an increase in the set of statistical data and the possibility of investigating fluctuations of the porosity coefficient within the studied model of the sample. For example, laboratory studies of a single core sample with a length and diameter of 3 cm make it possible to determine one pair of values of the open porosity factor, while a new method based on X-ray CT makes it possible to calculate one pair of values of the open porosity factor directly for a cylindrical sample, as well as several pairs of values for the virtual cubes selected in the sample, the number of which depends on the technical equipment of the computer processing the data and the content of heterogeneity regions that differ from each other in terms of structural and texture features.

Carbonate and terrigenous reservoirs from four Russian oil fields (Table 2) were selected as research objects (Abrosimov, 2017). Reservoir rock samples of standard size were initially investigated in petrophysical laboratories to determine the values of the open porosity factor by the gas-volumetric method for helium (Dakhnov, Kryukova, 2014) and the absolute permeability coefficient according to (State standart

Oil field	Age	Investigated rocks
Kharyaga	D_2af	Medium-grained and fine-grained sandstones
Krasnoleninskoe	K_1vk	Medium-grained and fine-grained, coarse-grained siltstones
Moskudinskoe	C_2b	Foraminiferal-algal and organogenic-detrital limestones
Vozeiskoe	D_3fm	Micro-grained limestone

Tab. 2. Objects of field research according to (Abrosimov, 2017)

26450.2-85, 1985). Then the samples were investigated by the X-ray CT method with a survey resolution of 2–10 μm; the size of the allocated virtual cubes for pore-type reservoirs is 300×300×300 pixels; on average, there are 10 cubes per one cylindrical sample. Based on the results of measurements, it was found that for all cylindrical samples the values of the reservoir porosity and permeability properties (flow properties) determined on the SkyScan X-ray tomograph are in good agreement with the data obtained in laboratory studies.

In the research paper (Sun et al., 2019) two samples of C1 and C2 limestones were studied by the X-ray CT method with the allocation of virtual cubes, using the digital core analysis technology. Sample C1 – grainstone with porous cement; sample C2 – grainstone with crustification type cement. To determine the optimal number of virtual cubes, two thin plates of samples C1 and C2 were studied by mercury porosimetry. The measurement results were used to plot pore size distribution plots for samples C1 and C2. From the analysis of the graphs, it was decided to separate three virtual cubes from each sample (Table 3).

Further, due to the insufficient resolution of 3D images of samples C1 and C2, each virtual cube was additionally divided (segmented) into eight cubes, to which various filtering methods were successively applied in order to improve the image quality and highlight three phases in virtual cubes: mineral skeleton, pores (pore space) and unrecognized areas. When calculating the porosity from 3D images, the selection of large pores was carried out according to the images of the original samples, the study of microporosity – from the 3D images of the smallest of the selected cubes. As a result of the research, the petrophysical relationships of porosity and permeability are presented.

According to the results of research by the authors (Abrosimov, 2017; Sun et al., 2019), the following was established:

1) computational and laboratory petrophysical relationships are close for rocks of various lithotypes;

2) the study of the heterogeneity of rocks, which affects the accuracy of determining the porosity, must be carried out using 3D images with different resolutions;

3) the heterogeneity of rocks when using the method of virtual cubes is considered positively, since an increase in the areas of heterogeneity leads to an increase in the amount of statistical data;

4) determination of the representative volume of a small sample (for example, with a diameter and height of 3 cm) for conducting porosity studies by the X-ray CT method is possible without additional drilling of smaller samples.

Thus, the X-ray CT technique with the selection of virtual cubes from different parts of the model is the most promising of the presented algorithms for calculating porosity of studying samples.

Sample	Selected virtual cubes	Linear size of the voxel (edge of voxel), μm	Size of 3D image in voxels
	C1sub4	4	980×980×930
C1	C1sub2	2	930×930×930
	C1sub0.5	0.5	860×860×900
	C2sub4	4	980×980×990
C2	C2sub1	2	960×960×970
	C2sub0.5	0.5	900×900×960

Tab. 3. Size of 3D images of virtual cubes (Abrosimov, 2017)

REV calculation of rock samples from porosity data determined using a stochastic network model

To create a 3D volumetric image of a core sample using the X-ray CT method, it is necessary to obtain a series of images, which are processed using special algorithms based on Radon transformations (Savitskii, 2015). Reconstruction of the pore space using X-ray CT is carried out in a direct way – according to the information on the density of the sample established on the X-ray tomograph, the topology of the pore space is recreated. In the works (Zhizhimontov, Stepanov, Svalov, 2017; Okabe, 2004; Markov, Rodionov, 2016), the reverse method for restoring void space is presented – stochastic reconstruction, which is used to predict the macroscopic properties of the object under study. This method is based on the construction of a stochastic pore-network model (PNM) of a core sample using the size distribution of capillaries and pores, their relationship, etc.

A pore-network model is understood as a set of intersecting pore channels, in other words, a network of pores and capillaries connecting them. Pores and channels in the simplest case can be represented in the form of geometric shapes – spheres and cylinders, respectively. The construction of such a model is accompanied by the use of experimental data on the structure of the pore space obtained:

1) by the method of three-dimensional computed tomography;

2) in the analysis of core sections;

3) when selecting a model of pore networks from three-dimensional images.

According to (Zhizhimontov, Stepanov, Shabarov, 2016; Idowu, 2009), the information required to create a PNM should include:

1) geometric information (dimension of pores and pore channels, porosity);

2) topological information (the location of pores in the model, expressed in coordination numbers);

3) correlation information (one-point and two-point correlation functions);

After establishing the necessary information, its generation begins in accordance with a special algorithm, which varies depending on the tasks of the research being carried out.

In work (Zhizhimontov, Stepanov, 2017), three samples of different lithotypes, determined from the results of core analysis, were studied. The first lithotype is coarse-medium-grained sandstone, the second lithotype is medium-fine-grained sandstone, and the third is siltstone. Based on the results of determining the topological and correlation parameters from the capillary pressure curves, the model was adjusted to core data. The applied algorithm is implemented in the form of a computer program that allows you to create a large number of PNM variants. The algorithm for determining the absolute permeability coefficient is based on simulating a steady flow of a liquid (single-phase) in a porous medium. To determine the REV of a sample of each lithotype, graphs of the dependence of the values of the porosity coefficient/ permeability coefficient averaged over all models on the size of the computational domain of the model were constructed. As a result of the work done, the following was established:

1) REV, determined from the graphs of fluctuations of the porosity coefficient for each lithotype, are approximately equal, therefore, in this case, the minimum representative volume (its value) depends mainly on the parameters of the algorithm used and is practically not affected by topological and geometric parameters;

2) REV, determined from the graphs of fluctuations of the permeability coefficient for each lithotype, differ significantly and are determined by the correlation parameters.

Thus, the main advantages of this technique compared to laboratory research methods are (Zhizhimontov, Stepanov, Shabarov, 2016; Zhizhimontov, Stepanov, 2017):

1) the possibility of studying low-permeability and unconsolidated reservoirs;

2) the possibility of increasing the set of statistical data to establish a reliable petrophysical relationship between porosity and permeability and accurately establish the minimum representative volume;

3) good agreement between the experimental values of reservoir properties, determined during the analysis of the core, and the averaged values, established by the digital core model.

The disadvantages of this method are its dependence on the results of examining samples on an X-ray tomograph and in thin sections, necessary for constructing the PNM, as well as the need to use powerful computers to carry out constructions.

It can be argued that, in the ideal case, a combination of X-ray CT and PNM is used in the study of complex rock samples. In this case, the X-ray CT method provides information about the features of the pore space and mineral grains, and the method of stochastic modeling makes it possible to calculate representative values of reservoir properties taking into account the geometric features (pores, pore channels) of the sample under study.

Investigation of the scale effect according to the data of open porosity and absolute gas permeability of cores established by the gas-volumetric method and the method of liquid saturation

Despite the advantages indicated in the work (Abrosimov, 2017) of determining the porosity of the studied rocks by the X-ray CT method, laboratory methods of petrophysical studies (liquid saturation method and gas-volumetric method) have not lost their relevance. So, in the work (Andersen et al., 2013), when describing methods for determining porosity and permeability as part of a standard core analysis, Schlumberger specialists distinguish, first of all, the porosimetry method, without mentioning the X-ray CT method as the most promising. Studies of the scale effect of reservoir rocks based on the porosity data of samples of different sizes, calculated by the two indicated methods, continue and are presented in scientific papers.

In works (Gurbatova, Kuzmin, Mikhailov, 2011; Serag et al., 2010; Mohamed et al., 2011; Gurbatova, Mikhailov, 2011), a comparison of the open porosity/ absolute permeability coefficients determined for the core of the initial diameter and drilled core samples of the standard size (according to the Russian classification) with a diameter and height of 3 cm (Gurbatova, Kuzmin, Mikhailov, 2011; Gurbatova, Mikhailov, 2011) or (according to foreign classification) with a diameter of 1.5 inches (3.81 cm) and a height of 3 inches (7.62 cm) (Serag et al., 2010), as well as samples 1.5 inches (3.81 cm) and 1 inches (2.54 cm) in diameter (Mohamed et al., 2011). Table 4 shows the objects and research methods in the considered articles, which are generally similar, but slightly differ in the sequence of actions.

In works (Serag et al., 2010; Gurbatova, Mikhailov, 2011), at the first stage of research, in order to assess the lateral and vertical anisotropy, the values of the vertical and horizontal permeabilities of core samples of the initial diameter were determined in two directions: the main and perpendicular to the main. The following is a comparison of the data obtained when considering core samples of the original diameter and standard size. The studies described in (Gurbatova, Kuzmin, Mikhailov, 2011; Mohamed et al., 2011) begin directly with the determination and comparison of the open porosity factors and the absolute permeability coefficients of core samples of the initial diameter and standard size.

Comparison of the data (open porosity and absolute permeability) of samples of different sizes was made as follows: in (Serag et al., 2010; Mohamed et al., 2011),

Research article	(Gurbatova, Kuzmin, Mikhailov, 2011)	(Serag et al., 2010)	(Mohamed et al., 2011)	(Gurbatova, Mikhailov, 2011)
Lithotype studied rocks	Microbial limestones	Carbonate reservoirs from the field Abu Dhabi	Carbonate reservoirs from the field Abu Dhabi	Carbonate deposits of the Timan-Pechora province
Linear dimensions of samples	Samples length and diameter 3 cm	Samples 3" long and diameter 1.5"	Samples with a diameter of 1.5" and 1"	Samples length and diameter 3 cm
	Core samples with initial diameter (68 mm)	Samples with original diameter (3-5") and up to 10" long	Samples with original diameter (4")	Samples of original diameter height 10 cm (diameter 10cm)
Methods for determining open porosity factor of the standard core samples	Liquid-saturation method	Gas volumetric method	Gas volumetric method	Liquid-saturation method
Methods for determining open porosity factor of the full diameter core samples	Gas volumetric method	Gas volumetric method	Gas volumetric method	Gas volumetric method

Tab. 4. Reservoir rock samples and methods of their study (Gurbatova, Kuzmin, Mikhailov, 2011; Serag et al., 2010; Mohamed et al., 2011; Gurbatova, Mikhailov, 2011)

cylindrical samples of standard size were drilled from core samples of the initial diameter in the horizontal and vertical directions (relative symmetry axes), for which the open porosity/absolute permeability coefficients are determined. Graphs comparing the porosity values of core samples of initial diameter and standard size samples with a diameter of 1 or 1.5 inches, as well as graphs comparing the values of the absolute permeability coefficient of horizontal and vertical cylindrical samples with a diameter of 1.5 inches (Serag et al., 2010; Mohamed et al., 2011). In works (Gurbatova, Kuzmin, Mikhailov, 2011; Gurbatova, Mikhailov, 2011), comparative tables and graphs of the values of open porosity and absolute permeability of core samples of the initial diameter and standard size samples drilled along the main filtration directions in the horizontal plane (Gurbatova, Kuzmin, Mikhailov, 2011).

Based on the results of the research, the following conclusions were made:

1) the vertical anisotropy coefficients of the permeability of the studied core samples with a complex pore space structure, according to the initial assumptions, can reach large values, thereby confirming the significant influence of vertical anisotropy on the accuracy of determining the absolute permeability (Serag et al., 2010; Mohamed et al., 2011; Gurbatova, Mikhailov, 2011);

2) the coefficients of lateral anisotropy of core samples with a complex pore space structure in some cases reach large values, which indicates the need to take into account the anisotropy of this type, contrary to the rather widespread opinion about an insignificant change in absolute permeability within different directions of the horizontal plane (Serag et al., 2010; Gurbatova, Mikhailov, 2011);

3) for low-permeability samples of complex carbonate reservoirs (<10 mD), there is a tendency: the permeability of core samples of the initial diameter exceeds the permeability of drilled samples of standard size, which can be explained by the better connectivity of pore channels in samples of the initial diameter (Serag et al., 2010; Mohamed et al., 2011);

4) the values of the open porosity factor of standard samples of carbonate reservoirs periodically exceed the values of the core of the initial diameter due to the manifestation of local microheterogeneities, while the core of the initial diameter best characterizes the structure of the pore space (Gurbatova, Kuzmin, Mikhailov, 2011; Serag et al., 2010; Mohamed et al., 2011);

5) the values of the absolute permeability of standard-size cylindrical samples taken in the vertical direction can be either higher or less than the values of the absolute permeability of the samples taken in the horizontal direction. The change in absolute permeability depending on direction (Serag et al., 2010) is explained by the presence of fractured, heterogeneous areas in the rock sample (Serag et al., 2010; Mohamed et al., 2011);

6) it is preferable to investigate the anisotropy of permeability on core samples of the original diameter, rather than on standard size samples drilled in the vertical and horizontal directions (Mohamed et al., 2011);

7) when considering carbonate rocks with a complex pore structure, core samples with a length and diameter of 3 cm (in Russia) and samples with a diameter of 2.54 or 3.8 cm and a length of 5–7.5 cm (in foreign laboratories) are not representative, therefore, the determination of representative values of porosity on such samples is not possible (Gurbatova, Kuzmin, Mikhailov, 2011; Serag et al., 2010; Mohamed et al., 2011; Gurbatova, Mikhailov, 2011).

Thus, in the studies under consideration, the non-representativeness of small samples of complex reservoirs was proved and the need to study larger samples, including cores of the initial diameter, was demonstrated.

Comparison of porosity data established by liquid saturation method, gas volumetric method and X-ray CT

Obviously, the liquid saturation method and the gas-volumetric method are direct methods for determining open porosity, while the X-ray CT and NMR methods are indirect. The reviews of articles, reasoning and conclusions presented below are devoted to the comparison of the values of porosity (and not methods) obtained by different methods. However, the reliability of porosity values depends on the accuracy (resolution) of the methods. Consequently, consideration of the principles and physical foundations of the methods is a prerequisite for comparing the X-ray data, the liquid saturation method and the gas-volumetric method.

Presented by the Center for Petrophysical and Geomechanical Research of the Schmidt Institute of physics of the Russian Academy of Sciences, the complex of laboratory work included the X-ray CT method, which is one of the key ones within the scope of work performed (Tikhotsky et al., 2017). As already noted, the main advantage of the X-ray CT method is the ability to study the structural features of rock samples at the micro level and determine the physical parameters of the core (especially substandard ones) with high accuracy (Abrosimov, 2017).

However, despite its widespread use, this method has its own disadvantages:

1) insufficient resolution of X-ray tomography;

2) lack of computing resources (Abrosimov, 2017).

To study the pore volume of reservoirs on an X-ray tomograph at the micro level, the following conditions must be met (Savitskii, 2015):

1) high spatial resolution (1 micron and less) of the tomograph;

2) the working voltage of the tube is about 100–150 keV.

In work (Savitskii, 2015), large-scale levels of core analysis and types of X-ray tomographs corresponding to these levels are presented. At present, the study of a core with a diameter of 10 cm and a length of 1 meter is carried out with the aim of identifying lithological inhomogeneities, in other words, macroheterogeneities larger than 0.4 mm in size. It is obvious that the identification of intergranular pores in carbonate and terrigenous reservoirs when examining a core interval 1 m long is not possible; detailed consideration of the structure of the pore space is carried out when studying standard samples with a diameter of 30 mm on microtomographs and samples of a smaller diameter (15 and 9 mm) on nanotomographs. It should be noted that the dimensions of the samples are determined by the technical characteristics of the tomograph (the distance from the source to the receiver, the power of the X-ray tube, the potential difference between the cathode and the anode). With an increase in the power of the X-ray tube, the penetrating ability of the rays increases, which leads to the expansion of the focal spot and, as a consequence, to a decrease in the sharpness of the image, therefore, when studying the core for each size of the sample, the power of the X-ray tube and the potential difference should be in a certain range.

The influence of the distance from the source to the receiver (SRD) on the sample size is not taken into account, since despite the fact that the X-ray intensity decreases with increasing SRD, the standard distance is used in X-ray imaging for a particular type of tomograph, therefore, when determining sample sizes this parameter can be neglected (Yanchuk, Yanchuk, 2013). When choosing a suitable X-ray tomograph for examining samples of a specific size, it is necessary to take into account the resolution of the equipment, which is determined by the size of the voxel and geometric magnification – the ratio of the distance from the source to the detector to the distance from the source to the axis of rotation of the object under study. To get a clear image, the voxel size should be minimal. Considering the geometric magnification, it should be noted that at a minimum distance between the source and the sample under study, the minimum voxel volume will be achieved, however, in this case, only a small part of the object will be examined, therefore, during measurements, one should choose the optimal option between the minimum "source-sample" distance and the volume of the investigated part of the sample (Manual for problem solving..., https://ostec-3d.ru/upload/iblock/0a1/Tomo_3003%20(pdf.io).pdf).

As already noted, to study the pore space of a sample, it is necessary to use micro-/nanotomographs.

Type of tomograph	Name	Nominal resolution, μm	Maximum sample diameter, mm	Maximum sample height, mm
Microtomograph of high resolution	SkyScan 1272	0.35	75	70
Microtomograph of high energies	SkyScan 1173	<5	140	150
X-ray multi-mode nanotomograph	SkyScan 2211	0.1	204	200

Tab. 5. Microtomographs and SkyScan nanotomograph (X-ray microtomography, https://lab-nnz.ru/wp-content/uploads/2017/11/Bruker_catalog_2017_site.pdf)

At present, it is especially important to study the core with nanotomographs (the results of measurements of the physical properties of the core are transferred to the reservoir as a result of scaling).

Table 5 shows the characteristics of microtomographs and nanotomographs developed by SkyScan (X-ray microtomography, https://lab-nnz.ru/wp-content/uploads/2017/11/Bruker_catalog_2017_site.pdf). Taking into account that the sizes of supercapillary and capillary pores, through which the movement of oil and gas is possible, are respectively 2.0-0.5 mm (2000–500 microns) and 0.5–0.0002 mm (500–2 microns) (Geology handbook, https://www.geolib.net/oilgas geology/poristost-porod.html), it can be concluded that the study of the pore space of the samples is preferable to carry out the SkyScan 2211 nanotomograph, which is confirmed by modern trends.

However, to obtain 3D images of a core of the initial diameter, a large computing power of graphics cards and a workstation processor is required, therefore, modern research is carried out using small samples (up to 10 mm). When studying carbonate rocks with a complex pore structure, cubic or cylindrical samples of this size are not representative, therefore, the scaling procedure will be incorrect. Determination of the porosity of a core with a diameter of 60–100 mm, samples of standard size (with a diameter and height of 3 cm) by the liquid saturation method or by the gas-volumetric method allows obtaining a large set of data that vary with the change in sample sizes. As a result, it becomes possible to establish the REV not only for samples with a diameter and height of less than 10 cm, but also for whole fragments of rocks with a length of 1 m and more, which is especially important when examining extended core intervals taken within one well.

It should be noted that the reliability of determining the values of porosity largely depends on the resolution of the measuring equipment, as well as on the features of the method used. For example, even in the case of using reliable equipment (sealed saturation tank and accurate analytical balance of class 1), the liquid saturation method is characterized by difficulties in determining the coefficients of open porosity:

1) poorly cemented samples;

2) highly porous rock samples containing significant cavities due to their possible destruction during the experiment (API RP 40. Recommended Practices for Core Analysis, 1998).

The gas-volumetric method for establishing open porosity is currently carried out using modern two-chamber porosimeters (API RP 40. Recommended Practices for Core Analysis, 1998). The accuracy of measuring the porosity of rock samples depends mainly on the technical characteristics of the equipment used. The disadvantages of such equipment include:

1) the need for constant, very accurate calibration of the porosimeter when using reference samples, the results of which in some cases can be canceled due to software errors;

2) the significant effect of small changes in temperature and pressure on the accuracy of the results of determining the porosity (API RP 40. Recommended Practices for Core Analysis, 1998);

3) a rather high total relative measurement error of porosity, which in the case of laboratory studies (not an ideal case) varies from 0.2 to 2%.

Thus, the use of the gas-volumetric method with the appropriate precision equipment makes it possible to obtain the values of the porosity of almost any rock samples, regardless of their geometric dimensions, degree of cementation (weakly cemented or cemented), the presence of clay components with a rather high error in some cases. The use of the liquid saturation method is limited by the properties of the rock sample, however, in the case of the analysis of rather dense rocks, high-precision laboratory equipment (analytical balance of the 1st class and sealed saturation vessels) makes it possible to determine the porosity of large samples (60–90 mm in diameter and 50–60 mm in height) with relative with an error of no more than 1–2%, which is obvious from the formula specified in (State standart 26450.1-85, 1985). Obviously, there are risks of incomplete saturation of a certain volume of void space of low-permeability and low-porosity core samples, therefore, the most accurate way to determine the porosity of a sample is to use both methods simultaneously in order to correlate the results obtained.

Influence of the scale effect on the accuracy of establishing the correlation dependence “core – geophysical logging” by the values of the porosity coefficient

Comparisons of the values of the porosity coefficient determined from the core and using the methods of production geophysics are accompanied by preliminary binding of the core by depth to the log curves using gamma-ray logging (GR) data and by the values of the natural integral activity of the core determined in laboratory conditions (Bolshakov et al., 2017). This binding method is the most reliable (Kuznetsova, 2017). In some cases, linking, for example, the core of carbonate reservoir rocks to the GR data is very difficult, therefore, it is necessary to use additional parameters calculated using well logging methods and from the core, for example, porosity (Bolshakov et al., 2017). After the core is tied, the “core – geophysical logging” correlations are built.

In the work (Atyutskaya, Kozlov, 2014), a comparison of the porosity values established during the study of the core and calculated from the data of acoustic sounding logging (ASL) and density gamma-gamma-ray logging (GGL) is presented. In the intervals of 2357–2363 m and 2370–2377 m, the porosity curve for ASL coincides with the porosity curve for the core in the best way as compared to the curve for GGL. In the interval 2363–2370 m, the situation is reversed, which is explained by the clay content of this interval. It has been established that the best option when constructing the correlation dependence "core – logging" by porosity values is the use of a set of logging methods, taking into account the features of each geophysical method and the considered geological section.

In (Khalid et al., 2015), a comparison was made of the porosity coefficients determined from cylindrical samples of small sandstones by the method of helium porosimetry and from GGL data. Correlation between laboratory data and values of porosity according to GGL for the two studied wells is quite large. Obviously, when studying samples of Jurassic sandstones, the minimum representative volume of the sample was not determined, therefore it is impossible to establish whether the use of core samples of standard size influenced the accuracy of determining the porosity coefficient. Given the presence of inhomogeneities in the studied sandstone samples, the probability of such an effect is quite high. Neglecting the scale effect can lead to inaccurate correlations.

Development of our own sampling technique for determining the representative core volume based on porosity data

The analysis of various methods for determining the porosity of rocks and sampling techniques is of practical importance. Based on the information obtained, it is proposed to study the interval of a limestone core with a length of 1 meter in order to determine the porosity. The graphs of fluctuations of the porosity coefficient with changes in the volume of the spherical region, presented in (Bear, 1972; Prilous, 2013), made it possible to establish that in order to calculate the minimum representative volume of the core interval, a sequential study of core samples from a smaller volume to a larger one is necessary. The proposed technique is as follows:

1) selection of cylindrical samples with a height and diameter of 3 cm every 25–30 cm perpendicular to the main axis of the interval of a cylindrical core;

2) sampling of 6–7 core samples with a diameter of 7.3 cm and a height of 5–6 cm every 5–8 cm perpendicular to the main axis of the cylindrical core interval;

3) determination of the coefficients of open porosity of the selected samples by the method of liquid saturation;

4) analytical determination of the open porosity factor of individual fragments of the core interval with a length of 20 to 40 cm, having an initial diameter;

5) determination of the porosity of the core interval according to the porosity data of standard samples and core with a diameter of 7.3 cm;

6) examination of samples in thin sections;

7) plotting the porosity fluctuation graph with a change in the sample volume, identifying the area of constant porosity values in order to determine the minimum representative volume and analyzing the porosity data to identify possible causes of the scale effect.

Conclusion

The article clarifies the concepts of upscaling and downscaling, scale effect and representative elementary volume. The scale effect of porosity should be understood as the dependence of the porosity of rocks on the linear dimensions of the core samples. Under the elementary representative sample volume for additive properties – the minimum volume of the core sample, which must be simultaneously larger than the volume of a single pore, that is, include a certain number of pores (microstructures) to obtain the required set of statistical data, and significantly less than the total volume of pore channels, in which fluid filtration is possible.

Methods for determining the representative volume of rocks by porosity values calculated by X-ray CT, NMR, liquid saturation and gas-volumetric method are analyzed. One of the most optimal methods for determining the porosity for its own technique has been established – the liquid saturation method, which allows studying large-volume samples, as well as individual core intervals and, as a result, obtaining a wide set of data for porosity analysis.

A comparison of the concepts of upscaling and scale effect has been carried out, as a result of which it has been established that the concept of upscaling is applicable to characterize the process of determining the equivalent reservoir porosity and permeability parameters when converting from a model with a higher resolution to a model with a lower resolution. It has been established that the study of unrepresentative samples of complex limestone of standard size leads to incorrect establishment of the correlation dependence "core – logging. It has been established that the study of unrepresentative samples of complex limestone of standard size leads to incorrect definition of the "core – logging" correlation.

For the successful implementation of an effective method for determining the size of a representative core in a petrophysical laboratory, as well as for studying the constancy of the REV of the core with depth, it is planned to study highly porous samples of different sizes, taken in intervals of 1 m.

Acknowledgments

The authors are grateful to the I.I. Nugmanov and E.R. Ziganshin (Laboratory of Petrophysical Methods for the Study of Geomaterials, Institute of Geology and Petroleum Technologies, Kazan Federal University) for the possibility of determining the porosity of core samples by the liquid saturation method; D.A. Pisarenko for help in working with the methodological apparatus of the study.

The authors thank the reviewers for valuable comments and recommendations, which contributed to improving the work.

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Manuscript received 1 July 2020;
Accepted 13 November 2020; Published 11 December 2020