Arctic Environmental Research

Arctic Environmental Research 18(4): 141–147
UDC [004.94:550.8](045)
DOI 10.3897/issn2541-8416.2018.18.4.141

Research Article

Experimental determination of porosity and permeability properties of terrigenous reservoirs for creation and validation of a digital core model

IP Belozerov[1]

1 *Northern (Arctic) Federal University named after M.V. Lomonosov (Arkhangelsk, Russian Federation)*

Corresponding author: IP Belozerov (i.belozerov@narfu.ru)

Academic editor: *Aleksandr I. Malov* ♦ **Received** 26 March 2018 ♦ **Accepted** 27 November 2018 ♦ **Published** 14 December 2018

Citation: Belozerov IP (2018) Experimental determination of porosity and permeability properties of terrigenous reservoirs for creation and validation of a digital core model. Arctic Environmental Research 18(4): 141–147. https://doi.org/10.3897/issn2541-8416.2018.18.4.141

Abstract

Digital core modelling is a vital task assessing original-oil-in-place. This technology can be seen as an additional tool for physical experiments capable of providing fast and efficient modelling of porous media. The objective of the paper is to determine experimentally the porosity and permeability properties of rocks and justify the possibility of using them for digital core modelling. The paper also validates feasibility of using the results of lithologic and petrographic surveys of thin sections in digital core modelling. The experimental studies of reservoir conditions allowed us to obtain curves of the dependence between the kerosene permeability of the terrigenous reservoir of the Buff Berea field and the temperature and to determine its main porosity and permeability properties. The paper also validates feasibility of applying the results of lithologic and petrographic surveys of thin sections of the reservoir to form the structure of the pore space of a digital core model by machine learning. The choice of this reservoir stems from the fact that the terrigenous sandstones of Berea Sandstone (USA) are characterised by minimal anisotropy of porosity and permeability properties, relatively high porosity and permeability, as well as uniformly sized grains of the composing rocks and good sorting. Oil industry experts therefore consider samples of these rocks to be most suitable for conducting applied research and testing various technologies. The results obtained were used to select the parameters required for modelling filtration flows in a digital model of the core.

Keywords

terrigenous reservoirs, porosity and permeability properties, digital core model, permeability change dynamics, supercomputer, modelling of filtration processes

Introduction

The technology of digital core modelling is currently a popular and developing direction in assessing the world's original-oil-in-place (Carpenter 2015, Arns et al. 2005, Mavko et al. 2003). It is now becoming more widespread owing to the development of computer and nanotechnologies, although foreign experts tried to apply it in practice for analysing reservoir rocks back in the 1980s (Kalam 2012, Knackstedt et al. 2009, Andraa et al. 2013).

In Russia, this technology is only just starting to develop. The first Russian laboratory for digital core modelling was opened in 2016. The works of Russian researchers on digital core modelling have been published relatively recently (Balashov 2016, Shandrygin 2014).

In the initial stage of creating a digital core model, the geometric model of the pore space can be presented in the form of a close packing of balls, the size of which is selected based on the data obtained during determination of the granulometric size composition of samples, microtomography and other studies. Yet rock particles are rarely shaped like balls (Tugarova 2004, Amosova 2000, etc.), so it seems appropriate to use not only balls as modelled particles but also more complex shapes, such as spherical cylinders, spherical squares and spherical cubes.

Various mathematical models and calculation methods may be used for modelling the filtration processes occurring in the reservoir. The most common include: pore network models, model of lattice Boltzmann equations, smoothed particle method, finite volume methods, diffuse boundary models, as well as models based on solving the Navier-Stokes/Stokes equations (Berezovsky et al. 2016). All these models and methods are used to perform particular tasks of modelling the processes occurring in the reservoir. As is shown in the paper (Berezovsky et al. 2016), they have certain disadvantages in terms of correctness of the mathematical model and the degree of its completeness, as well as in terms of a stable computational algorithm and the possibility of effective software implementation.

Nevertheless, methods of finite volumes (Gerbaux et al. 2010, Lemaitre and Adler 1990) and lattice Boltzmann equations (Hyvaluoma et al. 2012) are the two most popular methods for estimating the properties of filtration flows on a pore scale. At the same time, papers (Knackstedt et al. 2009, Hyvaluoma et al. 2012) show that the numerical approach used in these methods was characterised by a low accuracy in determining the permeability value.

When forming a digital core model, methods must be used that allow the shape and size of the grains forming the rock to be determined. Subsequently, based on the presented grain sizes, a porous medium model may be formed including various processes and initial parameters, by which permeability, porosity and other properties are calculated. The initial parameters of a digital core model include the distribution of the particle sizes of rocks, their placement and sorting, chemical interaction parameters, etc.

Various approaches and methods have been used in foreign studies to obtain the initial parameters of the digital core model. For instance, the study (Carpenter 2015) used 3D tomography of core samples and petrographic thin sections to model pores and particles of rock samples. Subsequently, the residual water saturation and relative permeability in the 2-phase system were calculated using the models created. According to the authors, the modelling results are close to the results obtained from direct measurements of core samples.

The study (Arns et al. 2005) used X-ray structural analysis of petrographic thin sections to determine the microstructure of the space of the digital core model, which allowed a 3D structure to be built of the rock space when modelling multiphase filtration of sedimentary rocks on a pore scale.

Despite the existing advantages of using 3D tomography and X-ray structural analysis of core samples and petrographic thin sections for obtaining initial parameters when building the volumetric structure of rocks, these approaches have some disadvantages. One of their main problems is that they fail to provide a complete description of and substantiation for the micro-processes occurring in the reservoir. This may be partially resolved by increasing the resolution of the images during tomographic studies of core material and accurately determining the granulometric size composition of rocks by laser diffraction.

In order to create and validate the digital core model, the author of this paper proposes using a set of parameters obtained from studying core material and lithologic and petrographic surveys of thin sections. In this case, the digital core model may be presented as a close stochastic packing that will form the microstructure of the core and it is then possible to apply the methods of molecular dynamics. Next, in the process of mathematical modelling of filtering processes, the results obtained on a supercomputer are compared with the results of physical experiments, making it possible to evaluate the effectiveness and accuracy of the model obtained.

An important step in creating the digital core model is to obtain the results of experimental studies of physical samples required for comparison with the results of computational experiments on a supercomputer. In order to obtain the experimental data required for subsequent studies, the main porosity and permeability properties of the terrigenous reservoir, as well as the kerosene permeability coefficients at various temperatures in reservoir conditions, were determined in the paper. The studies were conducted at the Innovative Technological Centre "Arctic Oil and Gas Laboratory Research" of Northern (Arctic) Federal University named after M.V. Lomonosov.

Buff Berea sandstone was selected as the terrigenous reservoir. This reservoir was selected owing to its homogeneity in terms of material composition and its porosity and permeability properties, as well as its wide recognition by oil industry experts in conducting applied research and testing of various technologies.

Characteristics of the study subject

The study subject is Buff Berea sandstone, representing material for synthesising a digital core model of terrigenous reservoirs that might potentially accumulate hydrocarbons.

Materials and methods

Ten standard-sized core samples were selected for study. Regular-shaped samples of rock were taken by drilling, trimming, surfacing and grinding in accordance with the requirements of GOST 26450.0-85 (Rocks. General requirements for selection and preparation of samples for determining reservoir properties. Date of issue: 1986–07–01.). Next, absolute permeability coefficients were determined for stationary filtration and linear gas flow in accordance with the requirements of GOST 26450.2-85 (Method for determination of the absolute gas permeability coefficient for stationary and non-stationary filtration. Date of issue: 1986–07–01.). Nitrogen was used as the gas.

The open porosity coefficients were determined according to GOST 26450.1-85 (Method for determination of the open porosity coefficient by fluid saturation. Date of issue: 1986–07–01.). Non-polar kerosene was used as the saturating fluid.

At the next stage, the samples were loaded into a UIK-5 (7) filtration unit (Fig. 1) to determine the kerosene core permeability coefficients depending on the reservoir temperature. This study involved conducting research to determine the kerosene permeability coefficients at 10 temperature regimes on 10 core samples (100 definitions in total).

To saturate the samples, the MS-535 manual saturator (Fig. 2) manufactured by Coretest Systems, Inc. (USA) was used, implementing a modern method of

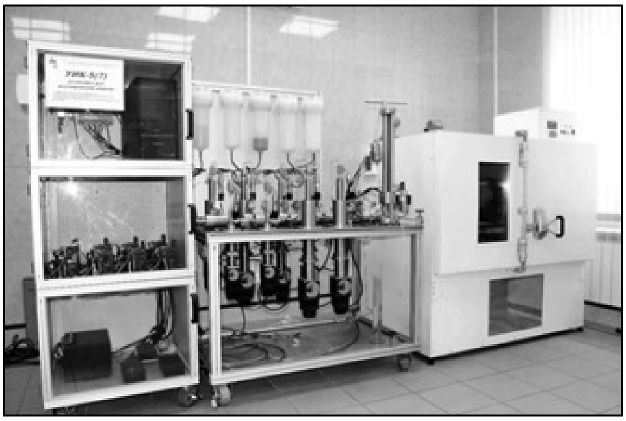

Fig. 1. UIK-5 filtration unit (7)

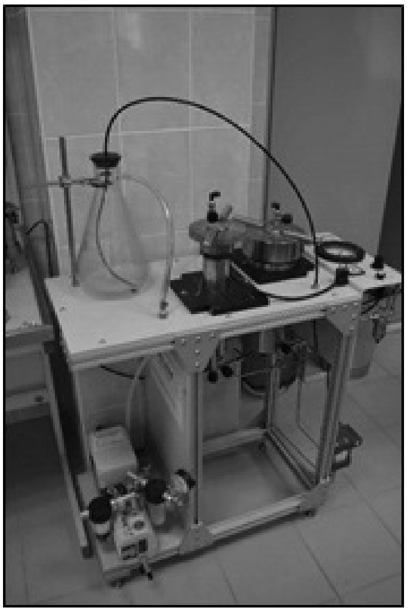

Fig. 2. MS-535 manual saturator

core sample saturation with liquids. Samples were weighed with an accuracy of up to 0.0001 grams.

A UIP-ATM.002 training and research permeameter was used to determine the absolute permeability coefficients (Fig. 3).

Fig. 3. UIP-ATM.002 training and research permeameter

Results

The results of determining the coefficients of open porosity and absolute permeability of the samples are presented in Table 1.

Table 1. Results of determination of coefficients of open porosity and absolute permeability of the samples

Sample No.	Length, cm	Diameter, cm	Absolute permeability coefficient, 10^{-3} μm^2	Open porosity coefficient, %
r-1	3.068	3.003	101.01	20.11
i6	2.682	2.997	125.64	20.42
i1	3.110	2.999	130.25	17.99
i2	2.722	2.996	96.43	18.89
i4	2.743	3.002	85.82	17.48
i7	2.854	3.003	91.64	18.55
229	2.974	2.995	121.13	19.63
1	3.580	2.995	101.032	18.07
i8	2.967	2.997	97.22	18.52
2	3.630	3.003	83.64	18.79

As can be seen in Table 1, the values of the absolute permeability coefficients of the samples vary from 83.65 to 130.25 10^{-3} μm^2. The average value of the absolute permeability coefficient was 103.38 10^{-3} μm^2. The values of the open porosity coefficients vary from 17.48 to 20.42%. The average value of the open porosity coefficient was 18.85%.

For mathematical modelling of the core, the reservoir temperature is an important factor influencing the values of the permeability coefficient. This is confirmed by studies conducted on core samples of the Buff Berea field. The graph of variance of the permeability of core samples depending on the temperature in reservoir conditions is presented in Figure 4.

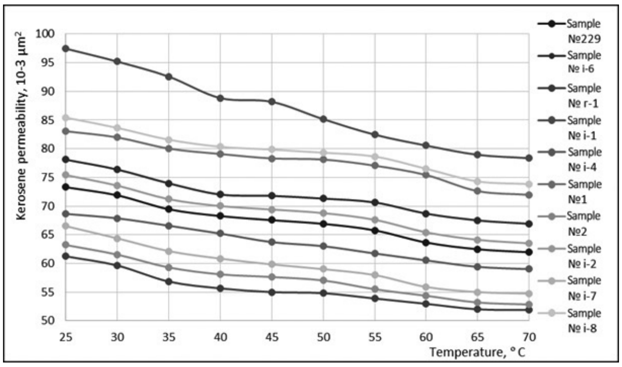

Fig. 4. Graph of variance of the permeability of core samples depending on the temperature in reservoir conditions

Discussion

In general, the dynamics of changes in kerosene permeability depending on the temperature in reservoir conditions shows a decrease in permeability as the temperature increases for a given collector. By selecting the function giving the most accurate description of the nature of the curves, a quintic polynomial function was chosen and equations were derived for each of the ten dependencies. Next, a generalised expression (1) of the dependence of kerosene permeability on the temperature in reservoir conditions was obtained for these rocks.

$$y = 0.000001x^5 - 0.0002x^4 + 0.203x^3 - 0.8642x^2 + 17.3x - 54.55 \quad (1)$$

where, y – kerosene permeability of the core, 10^{-3} μm^2; x – temperature, °C.

The resulting dependence may differ significantly for other terrigenous reservoirs. The reason is that the structure of terrigenous rocks has a huge number of pore channels of complex geometric shape and the rocks may differ significantly in their material composition over the entire length of the formation. The presence of capillary forces, contacts of rock-forming minerals with oil, that differ in strength and nature of interaction, and many other factors make it difficult to forecast the properties of terrigenous reservoirs that are characterised by significant differences. This is confirmed in a number of papers (Tugarova 2004, etc.). Yet this dependency has a methodological value since it makes it possible to apply percolation analysis when forecasting permeability in the digital core model, which is considered one of the most common methods for modelling fluid leakage processes in a porous medium (Dorokhov and Kafarov 1989).

When creating a close stochastic packing of a digital core model to bring the shapes of the grains of the modelled rock closer to the real ones, along with the results of determining the granulometric size composition of rocks, it is proposed to use the results of lithologic and petrographic surveys of thin sections. These results may later be used to determine the geometric parameters of the modelled particles by machine learning, which will allow extracting context-sensitive values of the lexical units from photographs and apply latent-semantic analysis to form a stochastic packing of the digital core model. This will have a positive impact on the approximation of the parameters of the generated digital core model to natural samples.

In the beginning stages of these studies, the initial image of the petrographic thin section of the terrigenous sandstone Berea Sandstone was transformed in order to establish an algorithm that could make it possible to quickly and accurately determine the characteristics of the microstructure of the rock pore space for digital core modelling. It has been found that, owing to compaction of the rock under study, it was difficult to determine the parameters of the grain boundary section. To solve this problem, the Hough transformation was applied in the OpenCV library of computer analysis algorithms of the thin section under study, making it possible to obtain the image shown in Figure 5.

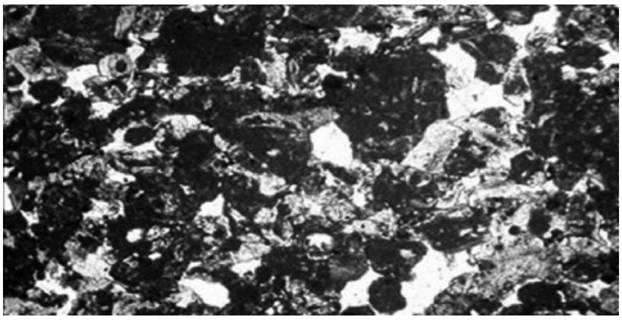

Fig. 5. Image of thin section after the Hough transformation

Next, a threshold transformation of the thin section image was performed. To capture the brightness of all the grain particles, an adaptive threshold transform was used, which considered objects not in one pixel but in its vicinity. The position of the particles was determined by converting the brightness of the pixel in its vicinity through weighted coefficients in accordance with the Gaussian function. The result of the threshold transformation of the thin section is shown in Figure 6.

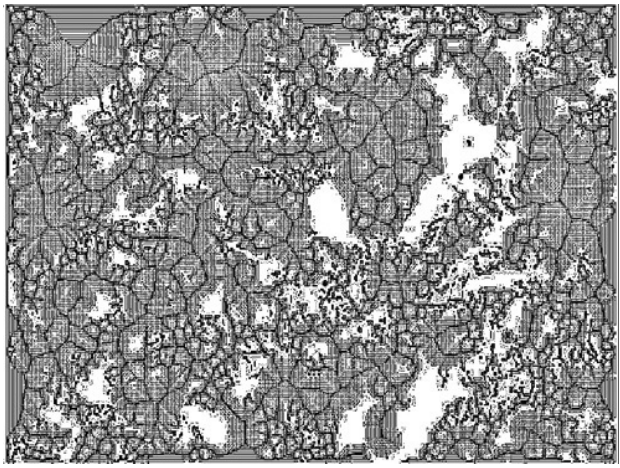

Fig. 6. Result of the threshold transformation of the thin section

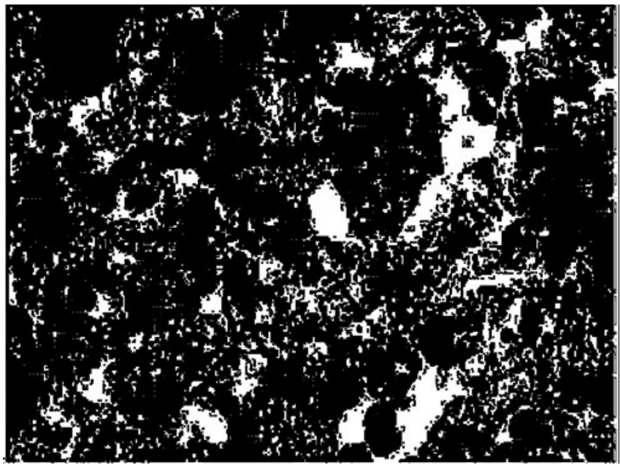

Fig. 7. Result of morphological transformation of the thin section

The threshold transformation made it possible to determine better the position of the grains in the microstructure of the rock under study. The next step was morphological transformation of the image required for determining the area of the voids in the thin section. At this stage, the colour of the rock grains was replaced with black and the voids with white (Fig. 7).

At the last stage, the black and white pixels were counted and the number of white pixels divided by the number of black ones, which corresponds to the petrographic method for determining porosity.

There are many proven software tools for high-quality and fast determination of the structure of the voids in petrographic thin sections using the threshold image transformation algorithm considered by the author. This algorithm may be applied in digital core modelling to form the structure of the pore space of the rock.

Conclusion

This paper presents the results of determining open porosity and absolute permeability (20 definitions), as well as kerosene permeability coefficients, at various temperatures in reservoir conditions (100 definitions). The studies were conducted according to the algorithm of threshold-transformation of petrographic thin sections images proposed by the author.

The results presented in the paper in the form of the established equation of the dependence of kerosene permeability on the temperature in reservoir conditions allows percolation analysis to be applied for forecasting the permeability of the digital core model. The results of lithologic and petrographic surveys of thin sections may be used to determine the geometric parameters of the modelled particles of stochastic packing of the digital core model using machine learning.

References

- Amosova OE (2000) Computer modelling of the structure and pore space of terrigenous sediments. Candidate of geological and mineralogical sciences thesis. Syktyvkar, 356 pp.
- Andraa H et al. (2013) Digital rock physics benchmarks – Part I: Imaging and segmentation. Computers & Geosciences 50: 25–32.
- Arns CH, Bauget F, Limaye A (2005) Pore scale characterization of carbonates using X-ray microtomography. SPE Journal 10: 478–484.
- Balashov VA (2016) Direct numerical modelling of fluid flow in the pore space of reservoir rocks. Candidate of physical and mathematical sciences thesis. Moscow, 108 pp.

- Berezovsky VV, Belozerov IP, Gubaidullin MG (2016) Approaches to creating a virtual core model of terrigenous reservoirs of oil and gas // Prospects and problems of development of oil and gas fields in the Subarctic zone of Russia. Arkhangelsk, 27–35.
- Carpenter C (2015) Digital Core Analysis and Pore-Network Modeling in a Mature-Field Project. Journal of Petroleum Technology 67(1).
- Dorokhov IN, Kafarov VV (1989) System analysis of chemical technology processes: Expert systems for the improvement of industrial processes of heterogeneous catalysis. Science, Moscow, 376 pp.
- Gerbaux O et al. (2010) Transport properties of real metallic foams. Journal of Colloid and Interface Science 342: 155–165.
- Hyvaluoma JM et al. (2012) Using microtomography, image analysis and flow simulations to characterize soil surface seals. Computers and Geosciences 48: 93–101.
- Kalam MZ (2012) Digital Rock Physics for Fast and Accurate Special Core Analysis in Carbonates. New Technologies in the Oil and Gas Industry 2012: 201–226.
- Knackstedt MA, et al. (2009) Digital rock physics: 3D imaging of core material and correlations to acoustic and flow properties. The Leading Edge 28: 260–264.
- Lemaitre R, Adler PM (1990) Fractal porous media IV: three-dimensional stokes flow through random media and regular fractals. Transport in Porous Media 5: 325–340.
- Mavko G, Murkerji T, Dvorkin J (2003) The Rock Physics Handbook: Tools for Seismic Analysis of Porous Media. Cambridge University Press, Cambridge, 329 pp.
- Shandrygin AN (2014) Digital Core Analysis for Flow Process Evaluation is Myth or Reality? SPE Russian Oil and Gas Exploration & Production Technical Conference and Exhibition. Society of Petroleum Engineers.
- Tugarova MA (2004) Reservoir rocks. Properties, petrographic signs, classifications: Guidance manual. St. Petersberg, 36 pp.