The application of X-Ray Computed Microtomography for estimation of petrophysical parameters of reservoir rocks

Vitalij Kułynycz\textsuperscript{a}, Michał Maruta\textsuperscript{b}

Department of Drilling, Oil and Gas, AGH University of Science and Technology,
30 Al. Mickiewicza, 30-059, Cracow, Poland
\textsuperscript{a,b}E-mail address: kulynych@agh.edu.pl, maruta@agh.edu.pl

ABSTRACT

In the reservoir geology, X-Ray microtomography (micro-CT) is mainly used for three-dimensional visualization of minerals and rocks. For rock sample testing, micro-CT technology enables quantitative measurements of the internal structure of rock material in a precise and non-destructive manner and, above all, allows accurate measurements of the spatial pore system. By using this method, you can get detailed information about porosity: it is possible to measure the length and number of channels pore, tracing their connections, visualization and quantitative assessment of their tortuosity and permeability, observing the penetration of water or oil in the rock, analyzing the degree of filling the pores of the rock different media and imaging and analysis of the wettability process. With this method you can also get a permeability analysis (in three orthogonal directions), estimate the fracture and hydraulic conductivity of the rock medium \cite{1}. The paper discusses the method of X-Ray microtomography, presents data acquisition and reconstruction of the internal structure of reservoir rocks for hydrocarbons. The results of research on petrophysical parameters of Polish reservoir rocks and global oil and gas deposits were presented using a modern research method, based on the literature review of micro-CT method.

Keywords: computer microtomography, petrophysical parameters, reservoir rocks
1. INTRODUCTION

In the field of visualization equipment and computer technology, it is support the implementation of very diverse 3D models of porous media that allow for the application of complex simulation methods. These methods appear to be very promising for assessing petrophysical properties in a fast and cost-effective manner, using only the knowledge of the 3D pore geometry of reservoir rocks [2]. One of the best and most modern research methods is the micro-computer tomography (micro-CT). In the field of reservoir rock characteristics, X-Ray tomography has become an interesting research technique, first demonstrated by Wellington and Vinegar [1987]. Since then, the world's oil industry has used the micro-CT method as an effective tool for analyzing drilling cores, providing non-destructive rock testing and imaging of their internal structures, with particular emphasis on the nature of the pore structure. X-Ray computer microtomography generates a three-dimensional image of the pore space of the rock sample to be analyzed, allowing for accurate measurement and analysis of the spatial distribution of the pores. Based on the results of micro-CT research we can get, among others information on porosity (volume, structure, location, pore size), number and length of porous channels and connections between them, as well as the structure of the pore network and their effect on permeability, as described in the following chapters [4].

2. METHODOLOGY

![Figure 1. Scheme of the basic stages of data acquisition](image-url)
In computer tomography, visualization of the internal structure of rock samples is done by means of a computer microtome. The article by the authors describes the methodology of the use of the X-Ray Benchtop 160 CT, used at the Oil and Gas Institute in Kraków, based on authorial works [5-7]. The test apparatus consists of three basic elements: the source of X-Ray manipulator, wherein the sample is inserted, and a detector recording X-Ray attenuation in the sample. In the microtomography, three steps are required: data acquisition, projection reconstruction and 3D image visualization to move from the real object to its spatial computer image [6]. Data acquisition is performed using the Inspect-X software and consists of correctly placing the sample in the holder using one of the available fixing elements. It is very important that the axis of rotation of the sample coincide (or is closest to) the axis of rotation of the handle, as this will give you the greatest possible magnification for a given sample. Once the required position has been determined, ensure that the sample is always in the field of vision during 360° rotation. The next step is to set the appropriate scan parameters (energy and radiation intensity and exposure time). Use these parameters to set the contrast of the image. It is important to not overwhelm the image with white. The sample table is rotated every 1° in the 360° range. During the measurement, the sample is X-Rayed (the differences in absorption properties of the materials, depending on the composition of the mineral, are absorbed by radiation in a variety of ways). Measurement data is collected in computer memory and then reconstructed [5].

Reconstruction of the projection is done using the CT-Pro program. In order to achieve the final result, you need to perform certain operations step by step. After reconstruction, images of different resolutions were obtained, which were spatial visualization of the scanned object. In the first stage the reconstruction results can be presented in the form of a series of two-dimensional sections of the object (Figure 1).

On such data can be made visualizations, and qualitative and quantitative analysis of the object under investigation. After the reconstruction, the files are imported into Avizo, developed by Mercury Computer Systems, Inc. The basic functions of this program help you to know the internal structure of a sample by separating elements with different values of X-Ray absorption. With their help you can distinguish any number of objects from a given range of X-Ray absorption. This software enables the representation of spatial distribution of pores in the rock sample and the structure of the rock skeleton. One way to get acquainted with the internal structure of the examined object is to view it as three views on perpendicular planes, which enables the orthoslice function. It allows you to quickly “search” a three-dimensional image by viewing single or multiple, perpendicular or oblique sections. In each of the directions, depending on the resolution with which the projections were made, there are from several dozen to several thousand such crossings. The thickness of each layer is equal to the size of the voxel obtained in a given direction. Once the pore space is separated, a detailed analysis of the internal pore structure of the rock can be made. On such data can be made visualizations, and qualitative and quantitative analysis of the object under investigation [5].

3. ESTIMATION OF PETROPHYSICAL PARAMETERS USING MODERN RESEARCH METHOD

Porosity and permeability are the basic features of reservoir rocks in terms of the size of the hydrocarbon flow to the well. To obtain full information on the collector properties of the
reservoir series, these parameters should be supplemented by rock fracture tests [3]. The ability to designate these parameters using modern computerized microtomography has been investigated and confirmed by scientists from around the world.

Analysis of porosity by X-Ray microtomography was carried out by Zalewska and Dohnalik [8] on three samples of carbonate rocks of the main dolomite formation on one of the Polish deposits. All samples came from a single well depth of over 3,000 m and had different petrophysical properties. The porosity of the test method was calculated as the volume ratio of the pore volume present in the sample to the total volume of the sample:

\[ Kp_{\text{micro-CT}} = \frac{V_p}{V_p + V_{sz}} \% \]  

(1)

where:

\( V_p \) – volume of the pore layer [woksel],
\( V_{sz} \) – volume of the rock framework layer [woksel].

The researchers reported the results of the micro-CT porosity evaluation for three dolomite samples with different porosities of <1.0%, 4.7% and 23.1%, respectively (Figure 2). The top row represents the two-dimensional cross-section through the sample, showing the difference in linear attenuation coefficient observed by the variation of gray levels, where black represents the air voids (porosity) and the gray color - the mineral skeleton. Bottom line illustrates 3D reconstructed and visualized micro-CT data, highlighting porosity (green) [8].

Figure 2. Results of micro-CT porosity evaluation for three dolomite samples [8, modified]
The most interesting type of porosity in carbonate rocks is fracture porosity and its spatial distribution is a key factor for evaluating correct flow rates of reservoir media. Determination of geometric parameters of fractures is possible, inter alia, through the use of direct methods such as laboratory analysis of cores [5].

In her work, Zalewska et. al [2] analyzed rock samples from 3 boreholes representing the works of the jury of the upper Carpathian Foreland and the works of the Celtic prehistoric monocline of the Zechstein. The resulting spatial resolution of the image was below 6.0 μm, which allowed a very good reproduction of the internal porous space structure. Individual fractures were separated and the width, inclination and distance between the adjacent fractures were measured. You can also measure the percentage of fracture volume in a rock sample, apart from measuring the angle of fractures, and, most importantly, accurately measure the width of the fractures at all times. In another study [5], carbonate rocks (limestone) were tested. The microtomographic images of the cross-section through fractures for one of the samples are shown in Figure 3. This figure represents the arrangement of three coordinates (X, Y, Z) and the oriented fracture. The Z axis (in blue) is parallel to the sample axis. Then the fracture angle was measured to the cross-sectional plane of the sample and the fracture aperture was measured. For an example sample two fractures intersecting at an angle of 22.6° are observed, whose widths are in the range of 34.23 μm to 90.09 μm, the slope angles of the fractures relative to the XY plane are 68.3° and 80.7°.

![Figure 3](image)

**Figure 3.** a) Photographs of the examined sample in real view and reconstructed cross section in microtomographic image  b) Microtomographic image of cross section through sample fractures [5,modified]
(X axis - red, Y axis - green, Z axis - blue).

Other researchers, among others, Polak et al. [9] states that the micro-CT method enables the fracture test and determines the factors that influence the change in fracture aperture, for example by dissolving minerals at elevated temperatures. The flow tests performed on natural fracture in 99% quartz at 20 °C, 80 °C, 120 °C and 150 °C, and at the artificial fracture in limestone at 20 °C. The author stated that this imaging allows for good and reliable estimation of fracture aperture [2].

Sugawara et al. [10] introduced a method of projecting a fracture to estimate its aperture and indicated that a precise assessment of the fracture distribution was possible when the rock sample was relatively homogeneous. Through this research it has been shown that X-Ray micro-CT is a good tool for visualization and analysis of rock samples [2].
Another important petrophysical parameter is the tortuosity of the pore channels ($\tau$), which directly influences the fluid flow through the volume of the rock and is a key factor in hydrocarbon recovery [11]. Tortuosity measurements were made by Zalewska et. al. [12] using computer microtomography on samples of carbonate rocks of the main dolomite formation originating from five wells of two exploration areas - Lubiatów and Sowia Góra (Figure 4). For samples from the Lubiatów region, the mean tortuosity value ranged from 1.177 to 3.19. Slightly lower values of this parameter were observed in the Sowia Góra region, where the maximum tortuosity also measured in three directions varied between 1.245 and 2.314, giving an average value of 1.632, while the tortuosity of the shortest measured flow paths ranged from 1.011 to 1.722 with an average value of 1.171. The mean tortuosity value in the analyzed region ranged from 1.086 to 1.746 [12].

Figure 4. Sample micro-CT image of all connected paths fluid flow in the sample - direction X from right to left. The tortuosity of the longest (A) and the shortest (B) flow paths in the X direction [12, modified]
Nayef Alyafei et al. [13] studied how Micro-Computed Tomography image resolution affects predicted flow properties (surface area, porosity and permeability). They obtained micro-CT scans of dry cylindrical cores of Clashach and Doddington sandstone (diameter 4.95 mm, length 10 mm) with the resolution (5.789 µm, 8.946 µm, 11.972 µm, 14.998 µm and 19.997 µm) for Clashach and (5.999 µm, 8.996 µm, 11.972 µm, 14.998 µm and 19.997 µm) for Doddington (Figure 5).
Researchers showed increasing average pore radius with decrease the resolution and the number of pores and throats increased with resolution for both sandstones (Figure 6). There was only a slight difference between both sandstones: Doddington had slightly larger pores and throats consistent with a higher permeability, however, the difference in size is too small to explain the significant difference in the permeability, which is controlled by the connectivity of the pore space. The number of pores and throats increases with resolution: the network extraction clearly does not identify a unique structure, but, as the image is refined, finds more network elements of smaller size [13].

Researchers studied also specific surface area which is the area of interface between pore and grain - computed on the images per unit volume. The surface area increased with improved resolution as finer features of the pore space are captured. With a finer resolution, more roughness was uncovered. In their study work they used three different simulators (network, Navier-Stokes, Lattice-Boltzmann and experimentally) to calculate the single phase permeability. As the resolution improved, the predicted permeability tends to increases, as more flow channels are observed (Figure 7). The two methods to compute the permeability directly on the image agree well in most cases, although the results are not identical, since the algorithms used to compute the flow are very different [13].

Auzerais et.al [15] used three-dimensional X-ray microtomography to image microstructures in Fontainebleau sandstone. Using a cylindrical core (approximately 37.5 mm long and 20 mm in diameter) they measured properties such as porosity, absolute permeability, pore volume to surface ratio ($V_p/S$), end point relative permeability, electrical resistivity and irreducible water saturation for oil primary drainage.

Figure 6. (a) Average pore radius and (b) number of throats, as a function of image resolution for Clashach and Doddington sandstone [13, modified].
Figure 7. Predicted permeability in the z-direction for each image resolution of (a) Clashach and (b) Doddington, compared to the experimental value [13, modified].
They employed a variety of computational methods, e.g., random walk techniques, finite difference techniques, and Lattice-Boltzmann method, to calculate the same properties in the three-dimensional X-Ray images that they had generated.

The computed values of porosity, absolute permeability, \( V_p/S \), and the end point relative permeability were in good agreement with their experimental counterparts, but this was not the case for electrical resistivity and irreducible water saturation. The samples that the authors had imaged for the theoretical calculations were much smaller (3.5 mm in diameter) than the sample they had used in the experiments, which may have contributed to the discrepancy between these two measurements and the associated model predictions [16].

Youssef et al. [17] states that the numerical simulation of petrophysical properties in complex carbonate rocks is a difficult task, particularly with regard to electrical properties, for which both the size and distribution of microporosity plays a very important role. Nevertheless, the author presents a method for simulating electrical properties using pore network models (PNM). Starting from the three-dimensional images of X-Ray computed tomography of carbonate rocks calculate the porosity parameter and the resistivity index, and the results obtained compare with the experimental values for satisfactory results [1].

Figure 8. Slices of the carbonate image: (a) the original 4 cm disk at 40 micron resolution showing the vugs (dark) and the dense dolomite phase (lighter shade) (b) the 5 mm plug cored from the disc at 2.5 micron resolution exhibiting pores across a range of scales. [18, modified]

Arns et al. [18] investigated a reservoir carbonate core plug, which has been imaged in 3D across a range of length scales using high resolution X-Ray microtomography. Data from the original 40-mm diameter plug (Figure 8) was obtained at the vug scale (42 \( \mu \)m resolution) and allows the size, shape and spatial distribution of the disconnected vuggy porosity, \( \phi_{vug} = 3.5\% \) to be measured. Within the imaged volume over 32,000 separate vugs are identified and a broad vug size distribution was measured. Higher resolution images, down to 1.1 \( \mu \)m resolution, on subsets of the plug exhibit interconnected porosity and allow one to measure characteristic, intergranular pore size. The apparent porosity of the core increases with enhanced image resolution. At the highest resolution the resolved porosity was less than
the value measured in the laboratory indicating a substantial presence of sub-micron porosity. Pore scale structure and petrophysical properties (permeability, drainage capillary pressure, formation factor, and NMR response) were derived directly on the highest resolution tomographic dataset. They showed that data over a range of porosity can be computed from a single plug fragment. Computations of permeability were compared to conventional laboratory measurements on the same core material with good agreement. Authors also have described the imaging of pores from the mm scale to the micron scale in carbonate core. While imaging at the micron scale enables the mapping of the primary flow pathways, important pore shape and connectivity information is not observed due to the limited resolution. Moreover, carbonates contain different mineralogies which can affect the measured petrophysical properties, hydrocarbon recoveries and production estimates.

Movement and trapping of immiscible fluids in permeable formations depends upon a complex combination of fluid properties, rock properties, fluid solid interactions, and forcing conditions. Karpyn and others [16] using X-Rays and visualization techniques to map the distribution of immiscible fluids, particularly trapped oil clusters, residing in a glass bead pack subject to different flow conditions. They analyze the effect of flowing conditions on the evolution of fluid microstructures using X-Ray microtomography. Spherical glass beads (0.425–0.600 mm in diameter), a water-wet porous medium, were packed inside a specially designed core holder. High-resolution imaging provides detailed mapping of pore structures resulting from bead packing, and characterization of fluid microstructures formed during sequential water and oil injections. Authors present spatial distribution of trapped oil clusters for the entire bead pack, as well as mechanistic explanations leading to the fluid configurations observed. They also presented that about 98% of the total trapped oil at the end of drainage and imbibition cycles corresponds to blobs that are smaller than 1 mm³. It was also shown that most blobs are larger than the mean pore size (0.03 mm³). The mean oil blob size was about 5 times larger than the average pore [16].

The first micro-CT images of a two phase saturated sandstone core plug were obtained at 30 µm resolution by Coles et al. [19] using a synchrotron light source at Brookhaven National Laboratories. More recently, a number of researchers Madonna et al. [20], Berg et al. [21] have monitored fluid saturation distributions in porous media using high resolution synchrotron imaging facilities as well as industrial micro-tomography instruments. Silin et al [22] studied the saturation distribution of supercritical CO₂ and water in sandstones using synchrotron imaging. Kumar et al [23] successfully imaged residual oil structure after spontaneous imbibition in sandstone and carbonate core plugs. Sufficient contrast between the two fluid phases and the rock as well as negligible measurement noise enabled different fluid phases to be discretely identified. In a similar study Blunt et al. [24] observed capillary trapping of supercritical CO2 in a brine saturated sandstone using micro-CT. The study confirms that capillary trapping enables efficient storage for CO₂ as long as the rock is non-wetting towards the CO₂ phase [25].

Tannaz Pak et al. [25] presented results of a suite of two-phase fluid displacement experiments performed on a dolomite core plug from an outcrop of Thornton formation in US. The experiments consisted of a series of fluid injections and in-situ micro-CT scans of the core in certain time steps during the drainage and imbibition displacement processes. The two main displacement processes controlling fluid flow in porous media, piston like displacement and snap-off of non-wetting phases were observed clearly. The fluid phases were brine and a mineral oil. In addition, pore scale imaging allowed to
assess the local wettability of the rock surface by observing the development of the wetting films as well as the oil-water/rock configuration (Figure 9).

**Figure 9.** Left: (a) A micro-CT slice after oil injection step and, (b) the corresponding slice after water flooding, (c) observation of oil-water/rock configuration, (oil-white, water-black, and rock-grey [25, modified].

Other researchers, Culligan et al. [26,27] used synchrotron-based X-Ray microtomography techniques to study variations of water/air and water/oil interfacial area in glass bead packs during drainage and imbibition cycles. They used three-dimensional images in order to compute interfacial areas and saturation. More uniform saturation profiles were observed in the water/oil system than in the presence of air, also leading to higher residual oil saturations, which was primarily attributed to the differences in interfacial tension between the fluid pairs. They observed an increase in air/water interfacial area as water saturation decreased. The trend reached a maximum and then decreased as the saturation continued to zero. The bead pack used by the authors was 7.0 cm long and 7.0 mm in internal diameter and had a porosity about 34%. The authors determined a Representative Elementary Volume (REV) and then focused their study on imaging a small, i.e., 5 mm, vertical section of the cell to increase the resolution and accuracy of their results [16].

Wettability is one of the main parameters that determines the position of the liquid in the reservoir pore space and fluid flow. The understanding of the relationship between wettability and distribution of water, oil and gas in the pore space is necessary to assess the efficiency of oil recovery [28]. Iglauer et al. [29] imaged two gasflood-assisted EOR processes in an intermediate-wet sandstone at a high resolution of 3.4 mm$^3$ in 3D with an X-ray micro-CT. Waterflooding an intermediate-wet oil reservoir proved to be quite efficient ($R_f = 52\%$), although direct gas flooding was even more efficient ($R_f = 66\%$). Significant incremental oil could be produced by alternating gas/water flooding ($R_f = 71\%$). The capillary-trapping capacity was thus significantly higher in intermediate-wet rock. In addition, they measured curvatures and capillary pressures of the oil and gas bubbles in situ, and analyzed the detailed pore-scale fluid configurations. However, the shapes of the curvature distributions stretched more to positive values in the case of oil and more to negative
curvatures in the case of gas. Porosities and oil, water, and gas saturations were subsequently measured on the segmented micro-CT images. Figure 10 clearly demonstrates that the oil saturation decreases substantially during the initial waterflooding from the connate water saturation ($S_{wc}$) to the residual oil saturation ($S_{or}$).

![3D topology of the oil (red) phase at various saturation states](image)

**Figure 10.** 3D topology of the oil (red) phase at various saturation states (a) connate-water saturation $S_{wc}$; (b) residual oil saturation $S_{or}$ [29].

The integrated use of three-dimensional X-Ray computed tomography of the core sample is a great alternative to the destructive methods of monitoring and evaluating test results from different technologies and simulation processes carried out in the bottom-hole zones of oil-saturated or gas-saturated reservoirs. In the study work, Orlov et. al [30] used X-Ray Micro Computed Tomography for estimation of physicochemical treatment efficiency of the Bazhenov formation of Western Siberia in Russia. The authors described the standard type of study to assess the porosity of productive rock, the method of evaluation of formation damage resulting from asphaltene deposits in the operation of wells with bottomhole pressure below the gas saturation pressure, and the results of the application of computer tomography in the evaluation of the results of classic acid treatment of bottom-hole zone of wells in study carbonate hydrocarbon bearing reservoir (Figure 11). The most interesting part of the process was observing the clogging of the rock, as asphaltene particles precipitated. This was done by using the computer tomography of the core. Often, precipitating asphaltenes contain metals, which increase the probability of their detection by X-ray imaging equipment, because of the reduction in the permeability of the X-rays. Their studies have shown that the application of computer tomography in some cases, allows to obtain data on the processes of reduction or increase in permeability taking place in a core due to the introduction of any of compositions in the bottomhole formation zone. Construction of three-dimensional models can improve the degree of comprehensibility and effectively visualize data of models built (for example, models of porous space and the rock matrix) [30].

In the recent years, significant progress of digital rock physics (DRP) following the computed tomography (CT) scan techniques has been made, which can directly image rock microstructures across a continuous range of length scales, from nanometre to millimetre scales [31]. Digital rock physics is able to compute the petrophysical parameters (e.g. porosity, permeability, elastic modulus) from three dimensional (3D) computed tomography...
images, which can make up for some disadvantages of traditional experiments. It also provides an understanding on how the large variations in petrophysical properties are caused by wide variations in pore type, pore shape, and pore interconnectivity. Huafeng Sun and others [32] provided an analysis of heterogeneity and estimation of petrophysical parameters in a heterogeneous carbonate rock sample from a Middle East reservoir using multi-scale micro-CT images (Figure 12) with three resolutions of 39.48 μm/voxel, 1.0357 μm/voxel and 65 nm/voxel.

**Figure 11.** Slices of core sample before and after the acidizing (by X-Ray computer tomograph) [30, modified].

**Figure 12.** Schematic diagram of multi-scale images of carbonate rock sample [32, modified].
They estimated porosity on the 3D DRM as fraction of pore voxels over the sum of all voxels. The absolute permeability was simulated by parallel lattice Boltzmann method (PLBM), which has been well verified using both analytical solution and experimental data. To estimate the static elastic properties, researchers offered the widely used method of Garboczi and Day [33], which is based on solving the basic Hooke's law equations of linear elasticity. As a result of their research on the basis computed tomography they have gained the range of pore-throat radius size of carbonate sample was from 0.1 μm to 10 μm, and most pores were under 1 μm. The estimated porosity (21.92%) and absolute permeability (6.54 mD) from the high-resolution images (65 nm/voxel) were close to the lab measurements (22.7% and 4.9 mD), which shows the accuracy of digital rock physics (DRP) in this particular sample. On the other hand, the simulated elastic modulus had a big difference with the measurements. The relative error were 77.23% and 87.68% for bulk moduli and shear moduli respectively, because the elastic properties do not only depend on the pore structure but also on the grain distribution and there were still some unresolved phases in the Nano-CT image. Also they simulated the fluid flow process in the connected pores of the rock sample. Although there were some pores in this subsample, the gas could not flow through these pores, as they were not connected. In addition, the fluid velocity distribution clearly indicated the heterogeneity and anisotropic nature of this carbonate rock [32].

Figure 13. Example (N1) of velocity distribution in three perpendicular directions simulated by PLBM (black color – pores, white - solid phase) [32, modified].

4. CONCLUSIONS

The aim of this work was to present by the authors the possibilities of X-Ray computed tomography in determination of petrophysical parameters of clastic and carbonate rocks. It has been confirmed on the basis of literature review that X-Ray microtomography is at present one of the best and most modern research methods used by geologists and petrophysics in Poland and abroad. This method enables visualization of the internal structure of the rock, helping to understand the petrophysical properties of the reservoir rocks, and allowing to simulate the flow phenomena of different fluid reservoirs in the rock pore space,
as demonstrated by the research of various scientists. This technology is characterized by high resolution of the apparatus, which is related to the very high quality of the images obtained, which allows to more accurately estimate the parameters tested. Most of the research results, estimated by the microtomography method, were consistent with the results of laboratory tests, indicating its accuracy. The paper presents results of measurements of various petrophysical parameters, among others. Porosity, permeability, oil and gas saturation, capillary pressure, wettability, electrical and elastic parameters of reservoir rocks. The possibility of using micro-CT in the fracture test for carbonate rock samples was presented. The visualization was presented, their aperture and width were measured taking into account the achievements of various Polish authors. Special attention has been paid to the general literature review of the use of micro-CT in the petroleum industry. The work presented by the authors was aimed at broadening the knowledge about the basic petrophysical properties of reservoir rocks in terms of the application of modern research method, i.e. microtomography.

References


-102-

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