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Potentialities of Investigation of Reservoir Hydrophobization by Compilation of X-Ray Core Tomography and Lateral Logging

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Abstract—The potentialities of studying rock wettability by X-ray core tomography are considered using Visean terrigenous reservoirs of the Solikamsk depression as an example. The studies included comparison of the tomograms of core samples in a dry state and saturated of sodium iodide solution, which acts as a radiopaque analog of formation water. Differences in impregnation of the core samples, characterizing their wettability, have been established. According to the tomography data, in the hydrophilic samples the solution filled all pores, except for a small portion of the largest ones. In the hydrophobic samples, there was no impregnation of both small and large pores in the central zone. Based on the tomograms, the rocks were divided into groups by their wettability: absolutely hydrophobic, with strong signs of hydrophobicity, with signs of hydrophobicity, and hydrophilic. Comparison of the results of tomography with the standard approach showed that the Tulbovich method commonly used for the study area does not fully reflect the rock wettability.

Comparison of the results of core tomography and study of thin sections with the results of electrometric logging shows their good agreement. The rocks with absolute hydrophobicity established by tomography have an anomalously high electric resistivity, >1000 Ohm·m, and the rocks with signs of hydrophobicity, >120 Ohm·m. For the hydrophilic intervals, the electric resistivity values are significantly lower, from 17 to 100 Ohm·m.

Thin sections of the core samples were studied. Their microscopic analysis has shown a higher content of organic matter in the hydrophobic rocks as compared with the hydrophilic ones. Few exceptions might be due to the study of only local thin sections of the samples.

Thus, rock wettability can be monitored by electrical methods, especially lateral logging. The results of the assessment of rock wettability by core study and well logging can be compiled for the exploration of Visean deposits of the Solikamsk depression. Geological models constructed with regard to the recognized zones of hydrophilic and hydrophobic reservoirs can be effectively used to optimize exploration of deposits, especially reservoir flooding.

Keywords: X-ray core tomography, electric resistivity, lateral logging, well logging, wettability, hydrophilic reservoir, hydrophobic reservoir, pore space structure

INTRODUCTION

At present, the majority of large- and medium-scale oil deposits of the Volga–Ural petroleum province (PP) are characterized by a high level of reserve depletion, while new discoveries are only predicted in the deposits with minor reserves at best. The southern part of Perm Krai is well-researched, and currently, only low-amplitude structures with initial recoverable reserves (IRR) of less than 1 MT are expected to be targeted here. The situation looks similar in the adjacent areas of the Volga–Ural PP (Udmurtia and Bashkortostan). For example, only a single deposit with IRR of more than 5 MT has been discovered in Bashkortostan since 1991 (Kontorovich et al., 2016).

The picture is radically different in the northern part of Perm Krai, where the drilling of prospective targets in the Solikamsk depression only started in the 1990s. In this region, most targets in development are characterized by a relatively low level of reserve depletion, with five deposits showing IRR values of over 5 mln tons. The recent decade has seen the discovery of a series of deposits still at their initial production stages, which include Rostovitskoe (IRR of 4.2 mln tons) and Sukharev deposits (IRR of 14.2 mln tons). According to the experts, new major targets may possibly be discovered in the Solikamsk depression area in the future (Kurchikov et al., 2013).

The region is characterized by the presence of light crudes with viscosities in the range of 1–3 mPa·s and relatively high porosity and permeability properties (PPP) of reservoirs with permeability (k) of about 100×10^{-3} μm^2. The Visean terrigenous complex represented by fine-grained and medium-fine-grained sandstones seems to have the highest oil reserves. The reservoirs display low clay contents (1–5%), and porosity varies from 10 to 20%.

Anomalously high electric resistivity values (ER) appear to be a distinctive feature of some oil-saturated intervals of Visean reservoirs. According to well logging data, resistivi-

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ties of the oil-saturated terrigenous reservoirs generally do not exceed 100 Ohm·m (and often fall within the range of 5–50 Ohm·m) in both the Perm Krai (Soboleva et al., 2014) and other studied areas (Nikiforova, 2008; Shilanov et al., 2011; Iskenderov, 2014). ER values for the Visean reservoirs do not always fit in this range, as they often exceed 200 Ohm·m and in some instances reach 2000 Ohm·m and above. Here, both standard and anomalously high ER values may be observed along oil-saturated reservoirs within the same well.

LINKS BETWEEN ROCK SURFACE WETTABILITY AND ELECTRICAL PROPERTIES

As mentioned above, ER values of over 200 Ohm·m are extremely rare in oil-saturated rocks, especially in terrigenous structures. According to the literature, increased ER values may be encountered in hydrocarbon source rocks (Kulyapin and Sokolova, 2013) due to the presence of large amounts of organic matter. However organic matter contents in Visean sandstones are on average not high enough only reaching about 1%. According to (Permyakov et al., 2017), a decrease in conductivity may be observed in frozen or hydrate-containing rocks. This also cannot be applied to Visean deposits of the Solikamsk depression with temperatures of about 29–33 °C, which do not fall below 12 °C even upon cold water injections during the experiments.

Authors believe that intervals with anomalously high ER values are associated with hydrophobization of reservoirs. It should be noted that, according to the studies of core samples recovered from Solikamsk depression deposits, the Visean terrigenous reservoirs are on average more hydrophobic, than the carbonate ones (Zlobin and Yushkova, 2014), while it is vice versa for other areas, since carbonate rock-forming minerals are more hydrophobic compared to quartz (Mitrofanov and Ermakova, 2009).

We share the opinion that hydrophobization of Visean reservoirs of the Solikamsk depression is most likely caused by the stabilization of ancient water-oil contacts (WOC) in their environment. Numerous occurrences of bituminous sandstones commonly referred to as black sandstones in a number of regions of the Volga–Ural PP (Bashkortostan, Tatarstan, etc.), are specifically associated with oxidation of oils at ancient WOCs (Mukhametshin and Galeev, 2014). In addition, bituminous products of oil oxidation may be extracted by subsequent portions of hydrocarbons. Bitumen extraction is a selective process depending on rock permeability, which in case of intense extraction throughout the whole geological section leads to complete bleaching of the rocks. These exact conditions are the ones prevalent in Visean reservoirs of the Solikamsk depression. Due to the absence of explicit signs of bituminosity, the Visean deposits formation was not previously linked to ancient WOCs and therefore the intense residual hydrophobization of reservoirs.

The hydrophobic nature of some intervals is indirectly confirmed by high nonuniformity of Visean deposits in terms of bed flooding efficiency. A decrease in injectibility during the first month of production is common for some areas, which is why injection operations underperform in terms of compensating for oil production (Soboleva et al., 2014).

Previously, reservoir development plans were rarely designed taking into account the wettability type, despite it has a clear effect on flooding processes, capillary impregnation, and distribution of residual reserves. For example, if flooding is implemented in a hydrophilic bed, it makes it significantly easier for water to migrate, than in a hydrophobic bed, which allows hydrophilic reservoirs to outperform hydrophobic ones in oil recovery parameters at the initial stages. At late stages, however, undisplaced unrecovered oil is left in large pores of hydrophilic reservoirs. In contrast, the oil, which adheres to pore surface in hydrophobic beds, increases oil recovery parameters by ensuring continuous filtration in the production well (Anderson, 1987). These aspects should obviously have critical value for planning well intervention operations.

Recognition of the regularities describing the effect of wettability on electrical properties of rocks is of great practical value, as it makes it possible to estimate wettability of almost any interval in the geological section in each particular well based on well logging data. It is known that ER values of oil reservoirs are determined by volume and structure of their pore space occupied by aqueous phase. As opposed to hydrophilic beds, aqueous phases in hydrophobic beds may have discontinuities, which leads to lower current conductivity.

ER values for clean reservoirs may be obtained as follows:

$$\mathrm{ER} = \rho_{\text{в}} \cdot T \cdot K_{\mathrm{p}}^{-m} \cdot K_{\mathrm{ws}}^{-n}, \tag{1}$$

where $\rho_{\text{в}}$ denotes the formation water resistivity, Ohm·m; T, the tortuosity of conductive channels; K_{p}, the porosity factor, fr. units; K_{ws}, the water saturation index, fr. units; m, the structural coefficient; n, the wettability index.

It is assumed that n for hydrophilic reservoirs fall within the range of 1.3 to 2.0, while $n > 2$ indicates the hydrophobization of the pore surface (Abasov et al., 2004). It can be seen from this formula that an increase in wettability index causes a sharp nonlinear increase in ER values of the rocks.

Lateral logging (LL) seems to be the well logging technique that provides the most reliable ER values of rocks. Current focusing in radial direction via guarded electrodes reduces distortion effects of the well and the host rocks on the measured ER values at propagation distance of 1.5 m, which makes this technique effective for geological sections with thin alternation of the beds. The maximum vertical resolution of the method is 50 cm. As a result, LL is more effective for Visean deposits compared to conventional electric probes, since it provides reliable estimates for thin beds even under unfavorable conditions (ρ_f/ρ_{df}). The data from wells with drilling mud resistivity of $\rho_{df} > 0.03$ Ohm·m for intervals with thicknesses of over 0.8 m were accepted as the conditioning data for numerical estimation of ER values.

In Fig. 1, the examples of studies using LL technique for a series of wells are presented, demonstrating that oil-saturated beds may be represented by both a high-resistivity section (depth range of 2207–2219 m in well 486; depth range of 2152–2168 m in well 45) and typical ER values below 100 Ohm·m (depth range 2127–2149 m in well 45; depth range 2440–2462 in well 588). Notably, fold changes in ER values in Visean deposits of the Solikamsk depression may occur throughout the section within the same well (Fig. 1). In the present paper, an anomalously wide range of ER values has been matched against wettability changes in the rock structure.

ROCK HYDROPHOBIZATION ASSESSMENT BY X-RAY CORE TOMOGRAPHY

Core sample wettability research makes it possible to study wettability at the microstructural level by assessing its nonuniformity within individual pores and capillaries. Here, various surface types may be present even in an isolated core sample. Theoretically, small pores surrounding the contact points of the grains should be more hydrophilic than the larger ones (Kovscek et al., 1993).

Quite a lot of approaches are available for rock wettability assessment using core samples (adsorption methods, Amotta method, centrifuge method, isothermal drying, etc.) (Dixit et al., 2000). Perm Krai deposits are studied by the Tulbovich method primarily due to relatively low time costs. The method is based on water displacement from the completely water-wet sample by hydrocarbon fluid by means of capillary forces and hydrodynamic pressure, with hydrocarbon fluid subsequently displaced from the sample by water. A quantitative estimate of wettability is represented by the value M, which identifies a preferential fluid for a rock on a linear scale as either water ($M = 0$) or kerosene ($M = 1$) (Khizhnyak et al., 2013). Comparison of the estimates obtained using the Tulbovich method with the results of isothermal drying shows good general correlation (Mikhailov et al., 2011), and with the overestimation of hydrophobicity obtained using the Amotta method (Gurbatova et al., 2016).

It should be noted that the methods considered above are based on different physical processes, all of them being indirect with respect to wettability. As opposed to them, pore space structure of rocks with visualized host fluids may be studied by X-ray core tomography (Alemu et al., 2012; Efimov et al., 2015; Galkin et al., 2015). Tomograms reflect the X-ray density of the studied medium on a gray scale, with the minimum density indicated by black and the maximum by white. Computer simulation of the results obtained using the method is performed in the Avizo Fire software suite (Berg et al., 2014). Given the standard core size (30 mm), X-ray tomography allows us to rather confidently visualize features (inclusions, pores, etc.) with sizes of 0.04 mm and above.

Wettability estimation technique based on X-ray tomography implies a comparison of tomograms for core samples in a dry state and saturated with sodium iodide (NaI) solution with a density of 1146 kg/m^3 (Efimov et al., 2016). In this case, the NaI solution acts as an analog of formation water due to identical filtration parameters. The use of NaI stems from the closeness of its X-ray density to that of the mineral framework of the rock and its stark difference from that of the pore space in a dry state (Air). Thus, it is possible to use the NaI solution as a radiopaque saturating solution (Alemu, 2012). Saturation is achieved by gradual filling of the sample chamber by vacuumed NaI solution, with the samples then being held in the solution for at least 3 hours. Before the saturation, the samples are subject to drying and vacuuming for at least 4 hours to prevent the formation of air bubbles that would impede the complete saturation. Note that the chosen saturation regimes and the equipment used were in conformance with GOST 26450.1-85.

Tomograms obtained for the samples in a dry state and saturated with NaI solution are presented in Fig. 2. In the dry state, pore space being the least dense medium is indicated by black color, rock matrix—by gray, and the most radiopaque inclusions—by white. When pore space is filled with NaI solution, its color grade changes to a brighter shade of gray. If the pores are not impregnated with the solution, then they are filled with air and are seen as black in tomograms.

An example of a complete absence of impregnation at the core of the sample is presented in Fig. 2*a*. The sample was recovered from the high-resistivity part of the geological section in well 486 (Fig. 1). Lateral zones of the studied cylinder, as well as its upper and lower faces, are subjected to impregnation with a depth of about 6 mm as a result of lateral absorption. Two distinct impregnation zones are observed in the saturated samples, specifically the saturated zone with rare, incompletely filled, large pores and the unsaturated zone, which barely has any areas filled with the solution. The unsaturated zone is located at the central part of the sample and has rough, but distinct boundaries. The cores of the dry and saturated samples appear practically identical in the tomograms (Fig. 2*a*), which means that the sample does not absorb water and is therefore fully hydrophobic. It should be noted that this effect was not observed in the experiments performed by the authors for any other exploration target in Perm Krai.

A slightly different tomogram of a saturated sample is presented in Fig. 2*b*, where a low impregnation zone is also found at the core. However, isolated currents indicating solution penetration, which characterize the zones with more hydrophilic properties can be seen in the unwashed zone (light gray, elongated, locally communicated channels). According to the tomography data, the sample is characterized by strong signs of hydrophobicity, which should undoubt-

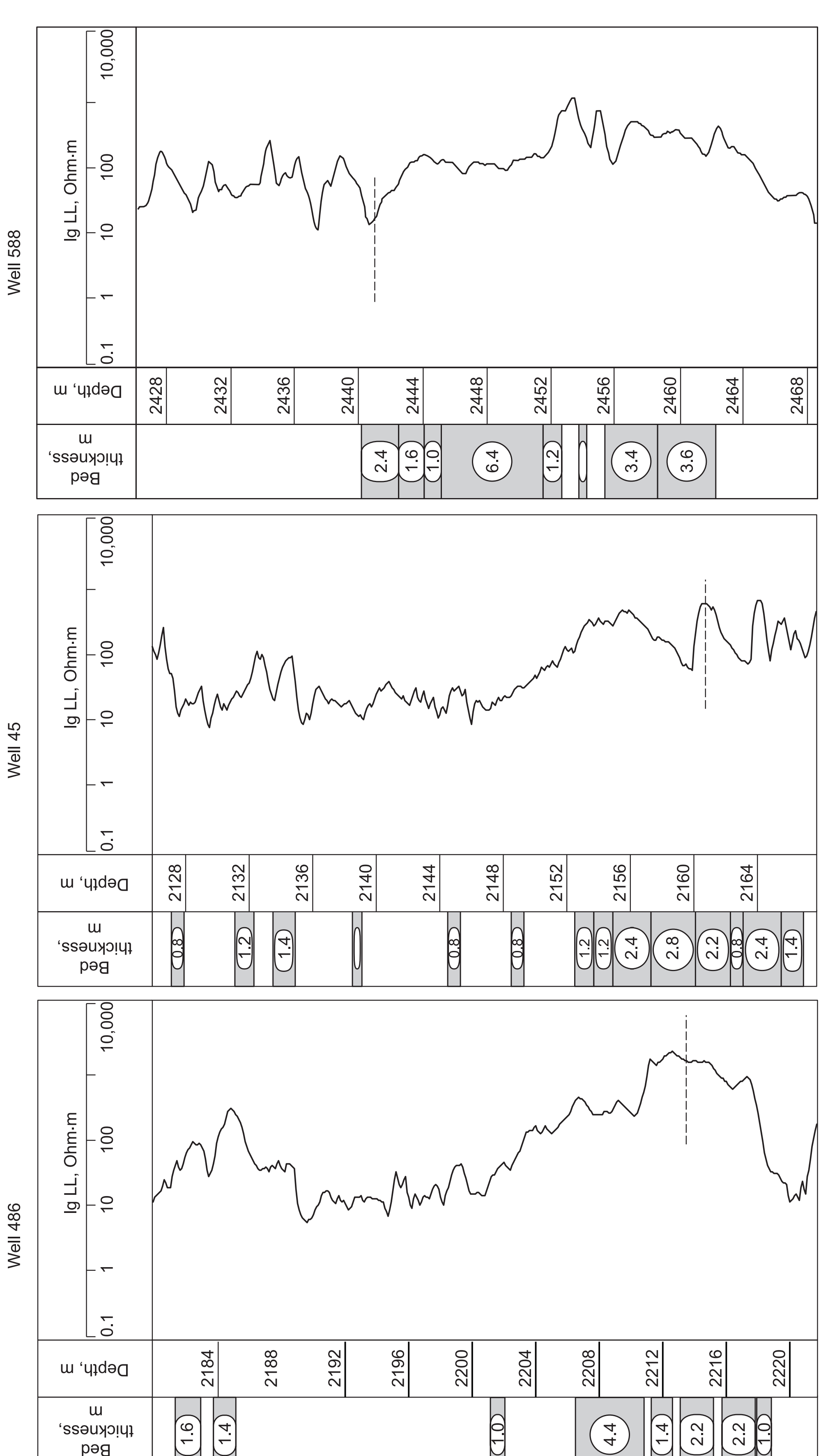

Fig. 1. Lateral logs for Visean deposits of the Solikamsk depression. Dashed line indicates the depth where core sample studied by tomography is recovered.

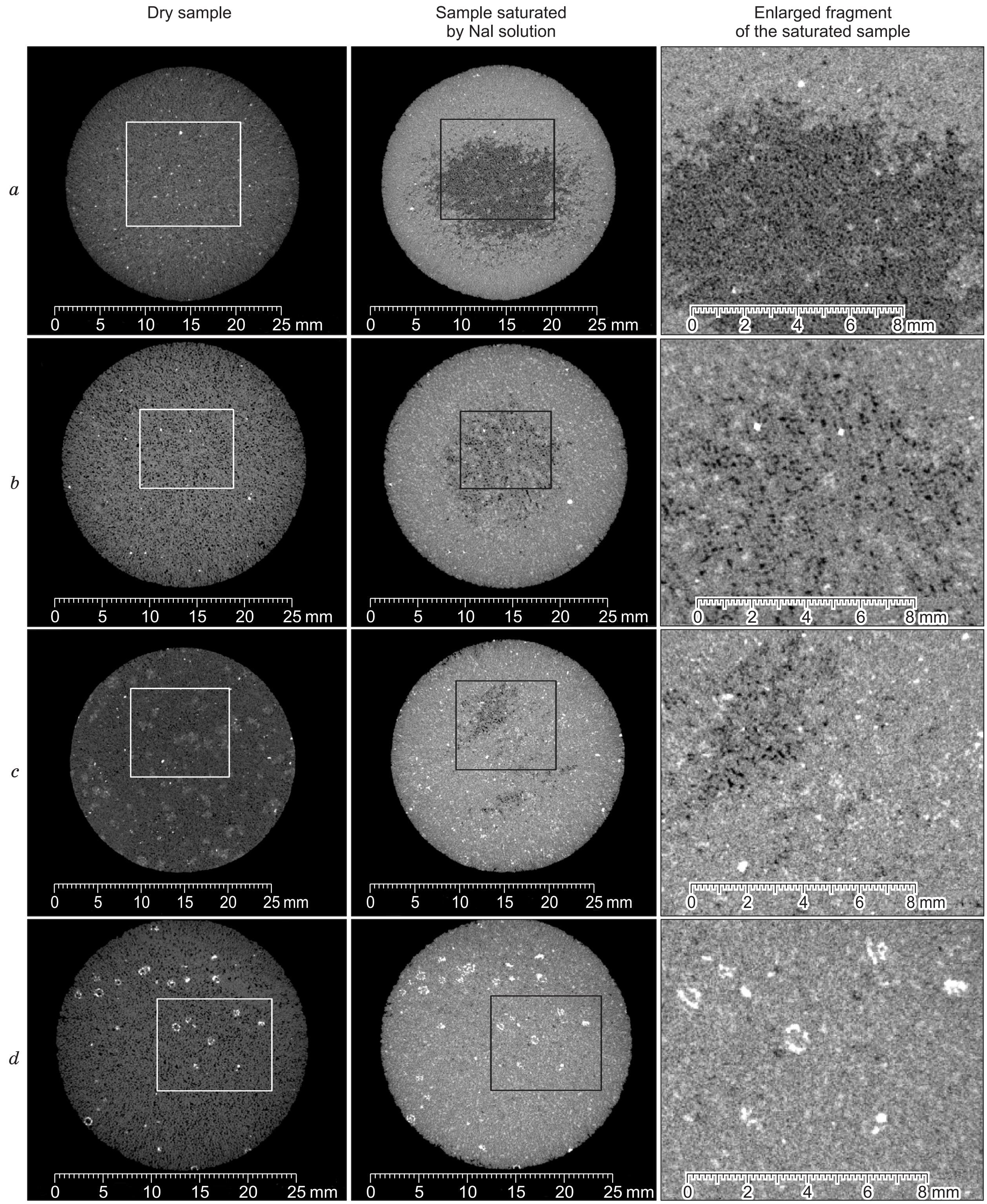

Fig. 2. Comparison of tomography sections for core samples in dry and saturated states. *a*, hydrophobic sample (cylinder 91712); *b*, sample with strong signs of hydrophobicity (cylinder 66541); *c*, sample with signs of hydrophobicity (cylinder 101116); *d*, hydrophilic sample (cylinder 109213).

edly affect fluid filtration processes. This sample was recovered from the high-resistivity area of the geological section in well 45 (Fig. 1).

Tomograms for the sample with signs of hydrophobicity, where low impregnation zones are only found in a few small areas, are presented in Fig. 2*c*. The unsaturated fragments have indistinct boundaries with rough edges. If the unsaturated zone is visualized with higher resolution, then we can see that all large pores and vast majority of small ones are still filled with air.

The tomogram for a fully hydrophilic sample from the low-resistivity part of the section in well 588 (Fig. 1) is presented in Fig. 2*d*. When the cylinder is subjected to impregnation, NaI solution fills all small pores and most of the large ones, and the prevalent background color associated with rock matrix changes to light gray. In addition, it can be seen from the tomogram that a small portion of the largest pores remains unaffected by the solution, which is why they still appear as black (Fig. 2*d*).

INVESTIGATION OF ROCK COMPOSITION AND STRUCTURE IN THIN SECTIONS

Thin sections were prepared to investigate the structural space of rocks from the central parts of 12 cores in more detail and estimate their wettability based on tomography data. These thin sections were used to study mineral compositions of the rocks and their inclusions, as well as the specific features of their texture and structure. By comparing the microscopic description of thin sections with the X-ray tomography results, we were able to state problems of interpreting the areas with increased X-ray density in tomograms, determining mineral compositions of grains, and identifying significant differences in samples with various wettability types.

It should be noted that the comparison of thin sections with the X-ray tomography results is restricted by the difference in scales owing to the resolution of methods and the area and volume of the objects being studied, i.e., for the resolution of up to 0.002 mm thin section thickness is 0.02 mm, the area is 25 × 25 mm, and the field is 2 × 3 mm. When X-ray tomography is applied to a standard core, the resolution is reduced by an order of magnitude (up to 0.04 mm), but a much larger rock volume may be studied.

Images of thin sections for the identified groups with different wettability estimates are presented in Fig. 3. Thin sections were imaged using both crossed Nicols (Fig. 3, right column) and parallel Nicols polarization (Fig. 3, left column) for the same fragments. Both types of images are shown for the best possible characterization of the samples, i.e., crossed Nicols polarization makes it possible to see the mineral composition peculiarities more clearly due to anisotropy of optical properties of minerals, while parallel Nicols polarization provides a better representation of the pore space structure and organic matter partially existing in a scattered dispersed state.

According to the thin section analysis, most of the studied samples are medium-fine-grained quartz sandstones. The rocks in the samples are formed by semi-rounded angular quartz grains sized from 0.02 to 0.8 mm, silt grain contents ranging from 7 to 20%. Fragments of siliceous rocks are represented by chalcedony micrograins. Clayey-hydromicaceous contact cement is observed with local instances of pore-film cementation. The mineral composition is represented by quartz (69–82%), calcite (from isolated grains to 5%), fragments of siliceous rocks, siderite, clayey-hydromicaceous matter, leucoxene, zircon, pyrite, muscovite (from isolated grains to 2–3%). Comparison of thin sections with the X-ray tomography results showed that siderite, zircon, and pyrite grains display increased density in tomograms.

In two core samples, intergranular space was partially (5 and 10%) filled with inclusions of opaque brownish-black bitumen. An example of a thin section is presented in Fig. 3*a*. The fraction of grain size of 0.15–0.25 mm prevails in the rock, with silt grain contents reaching 7%. Siderite forms oval- and irregular-shaped earthy aggregates with sizes of up to 0.05 mm. An angular greenish-blue tourmaline grain of isometric shape with a size of up to 0.13 mm is present in the thin section. Clayey-hydrmicaceous contiguity (contact) cement is observed with local instances of basal-pore cementation, which colors organic matter brownish-black. Intergranular space is partially filled by inclusions of opaque brownish-black bitumen, and the pores are round and irregular-shaped with sizes of up to 0.6 mm (Fig. 3*a*).

Examples of thin sections with organic matter contents above 1% are presented in Fig. 3*b*, *c*. In both cases, the rocks are formed by quartz grains with prevalent sizes of 0.25–0.30 mm, with silt grain content reaching 7%. Round and irregular-shaped pores with sizes of up to 0.4 mm can be seen in the intergranular space. In the first case, round and irregular-shaped black inclusions of organic matter with sizes of up to 0.1 mm are observed. Rare colorless muscovite and hydrated biotite flakes, as well as oval- and irregular-shaped earthy aggregates of siderite with sizes of 0.05–0.20 mm, are observed. Clayey contact cement is observed with local instances of film-type cementation. Tabular calcite grains with sizes of up to 0.2 mm can be seen locally, which can be considered a pore-type secondary cement. Accessory minerals observed include oval and angular zircon grains with sizes of up to 0.1 mm and irregular-shaped leucoxene aggregates (Fig. 3*b*).

In the second case, organic matter colors the clay matter light brown and forms rare short curved brownish veinlets between quartz grains. Isolated round-shaped reddish-brown gelified aggregates and rare transparent muscovite flakes sized up to 0.15 mm are observed. Clayey-hydromicaceous contact cement is observed with local instances of basal-pore and film-type cementation. Secondary calcite forms irregular-shaped aggregates, which then act as basal-pore cement (Fig. 3*c*).

An example of thin section with insignificant organic matter content (below 0.5%) is showed in Fig. 3*d*. Fractions

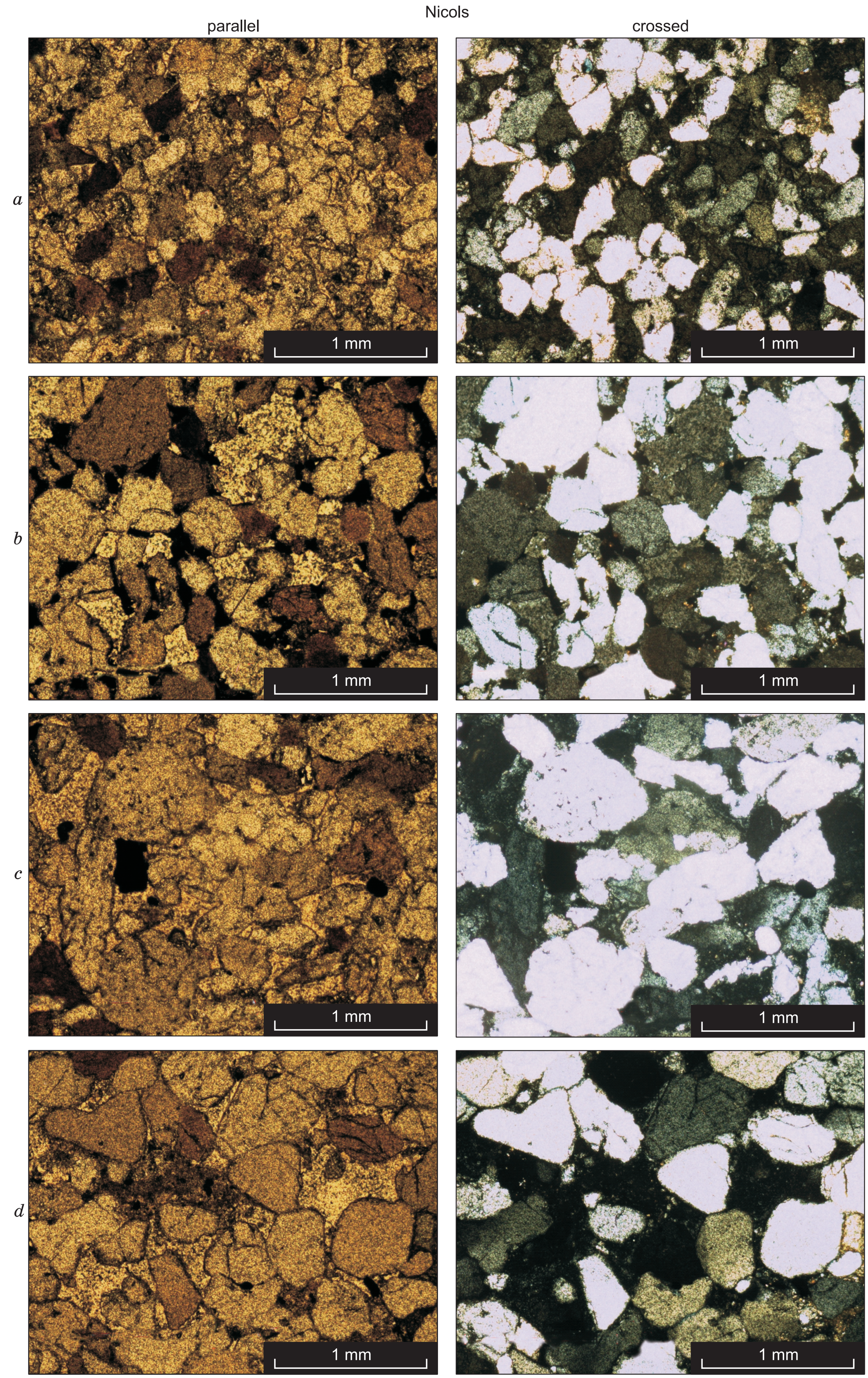

Fig. 3. Images of thin sections of cores in parallel and crossed Nicols polarizations. *a–d*, see Fig. 2.

of grain size 0.25–0.35 mm are prevalent, with silt grain content reaching 7%. Pores sized up to 0.4 mm can be seen in the intragranular space. Muscovite is observed in the form of rare transparent flakes sized up to 0.15 mm. Organic matter forms rare short curved brownish veinlets between quartz grains. Isolated round-shaped reddish-brown gelified aggregates are observed as well (Fig. 3*d*).

The analysis performed during the classification of the studied samples by wettability types did not show any significant differences between the classes either in structural or in mineral rock composition. However, the differences were found when organic matter contents were analyzed. Generally, samples with signs of hydrophobicity displayed increased organic matter contents, while in the hydrophilic samples organic matter contents were at their minimum.

COMPILATION OF THE TOMOGRAPHY DATA, MICROSCOPIC STUDIES OF THIN SECTIONS AND ELECTRIC WELL LOGGING FOR ROCK WETTABILITY ASSESSMENT

We believe that X-ray tomography provides the most reliable visualization of hydrophobic surface zones in core samples. In addition, the results of thin section analysis are taken into account to understand the mechanism of rock surface hydrophobization. However, there is never enough core sample data to characterize the bulk of the deposits due to high drilling costs. Therefore, core sample studies need to be tied to the results of electric well logging, primarily LL. To do this, we analyzed a series of methods, including conventional core sample studies, X-ray core tomography, thin section analysis, and electric well logging. The research results are summarized in the Table 1.

Based on the tomography data, two samples characterized by the highest ER values (K_p and k) and are classified as hydrophobic based on their wettability M (M = 0.02 fr. units) are identified as absolutely hydrophobic. According to thin section analysis, organic matter contents in them are estimated at 1%. According to the LL data, both samples have maximum ER values over 1000 Ohm·m.

Based on the tomography data, strong signs of hydrophobicity are recognized in two core samples. The thin section analysis showed the presence of bituminous inclusions in both samples. ER value was 600 Ohm·m in the first sample, and 80 Ohm·m—in the second one. In the second case, the lower ER value may be explained by extremely low PPPs in the studied sample (K_p = 11.4 % and k = 0.023 μm^2), which lead to high residual water saturation. The range of ER values calculated using (1) shows that it is an increase in K_{ws} due to growing sectional area of the aqueous phase, that leads to a sharp increase in rock conductivity. A reduced ER value in this oil-saturated interval is also linked to its small thickness (less than 1 m), which is why the measurements are more significantly affected by the adjacent low-resistivity rocks.

Based on the tomography results, four core samples were attributed to the group with signs of hydrophobicity. The samples are characterized by close PPPs with K_p ranging from 13.0 to 17.4% and k from 0.088 to 0.150 μm^2. According to the thin section analysis, organic matter contents exceeded 1% in three samples, while the remaining sample showed a value of 0.5%. In all the qualified LL surveys (except for one survey with a logging flaw) in the intervals, where core samples from the considered group were recovered, increased ER values ranging from 120 to 710 Ohm·m were observed. Wettability types determined in core samples from the considered group using Tulbovich method range from absolutely hydrophobic (M = 0.02 fr. units) to almost hydrophilic (M = 0.80 fr. units), which seems questionable.

Four of the studied core samples with close PPPs, i.e., with K_p ranging from 14.1 to 18.1% and k from 0.107 to 0.355 μm^2, are classified as hydrophilic. In all cases, ER val-

Table 1. Results of core sample studies using conventional methods, X-ray tomography, and thin section analysis

Cylinder No.	K_p, %	k, μm^2	M, fr. units	ER, Ohm·m	Thin section study	Wettability based on tomography
84911	21.5	0.749	0.02	3000	Organic matter (OM) = 1%	Hydrophobic
91712	21.4	0.379	0.02	1800	OM = 1%	Hydrophobic
66541	13.5	0.055	0.03	620	Bituminous aggregate 10%	Strong signs of hydrophobicity
120413	11.4	0.023	0.30	80	Bituminous aggregate 5%	Strong signs of hydrophobicity
103699	14.7	0.088	0.65	710	OM = 1.5%	Signs of hydrophobicity
59578	13.0	0.150	0.02	370	OM = 1%	Signs of hydrophobicity
101116	13.6	0.143	0.41	120	OM = 1%	Signs of hydrophobicity
114022	17.4	0.276	0.80	N/A	OM < 0.5%	Signs of hydrophobicity
102120	14.1	0.107	0.02	75	OM = 2%	Hydrophilic
108484	14.6	0.147	0.82	100	OM < 0.5%	Hydrophilic
112526	18.1	0.335	0.03	17	OM < 0.5%	Hydrophilic
109213	15.6	0.189	0.18	17	OM < 0.5%	Hydrophilic

ues in hydrophilic intervals did not exceed the standard value of 100 Ohm·m. However, three of the four samples (75%) were incorrectly classified as hydrophobic (*M* ranging from 0.02 to 0.18 fr. units) using the Tulbovich method. According to the thin section analysis, three samples showed organic matter contents of less than 0.5%, while in the remaining sample it was 2%. Increased organic matter content in the latter case may be attributed to increased bituminosity interval located, according to the core data, 20 cm below the depth of the studied sample, which is confirmed by a sharp increase in ER value up to 1000 Ohm·m.

CONCLUSIONS

The use of X-ray tomography for wettability assessment provides a visualization of the filling of pore space in rocks not attainable by conventional techniques. Comparison of the tomograms based on core samples in a dry state and saturated with sodium iodide solution seems to be the optimal wettability assessment technique. The rocks may be classified based on wettability type using these tomograms as follows: absolutely hydrophobic, with strong signs of hydrophobicity, with signs of hydrophobicity, and hydrophilic. Comparison of the tomography results with the conventional approach showed that Tulbovich method commonly used in the studied region does not always adequately represent rock wettability.

Comparison of the results of core tomography and thin section analysis with electric well logging data allows us to conclude that they are in a good agreement. The rocks identified as absolutely hydrophobic based on the tomography data show anomalously high ER values of over 1000 Ohm·m, and the ones with signs of hydrophobicity over 120 Ohm·m. However, ER values may be significantly reduced in low-porosity hydrophobic samples due to increased water saturation. Significantly lower ER values ranging from 17 to 100 Ohm·m are typical for hydrophilic intervals.

The analysis of thin sections prepared for the samples studied using tomography showed that more hydrophobic rocks tend to have higher contents of organic matter in a scattered dispersed state compared to hydrophilic ones. The exceptions observed in some cases may be explained by the thin section analysis not covering the whole variety of samples.

Thus, as a result of the present research, we have confirmed that hydrophobization of rocks may be tested using electric well logging techniques, primarily lateral logging, which makes it possible to assess rock wettability types in deposits based on well logging data. Apparently, to derive more detailed statistical regularities would require a larger number of X-ray core tomography experiments. Geological models, which take into account the mapping of hydrophilic and hydrophobic reservoir zones, may turn out to be effective in optimizing the development of oil deposits, especially with regard to effective flooding of seams.

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