

Water-free oil reservoirs: origin and morphology

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Abstract. The features of the morphology and composition of secondary minerals in the reservoir zones of the White Tiger (Bach Ho) deposit (shelf of South Vietnam) and deposits in clay rocks of the Bazhenov formation of the Salym area of Western Siberia are considered. It is shown that the common for these fields is the formation of a reservoir as a result of the leaching effect of high-temperature fluids. The genesis of the reservoir is determined by a complex of secondary minerals, obviously of hydrothermal origin, partially filling caverns and cracks in the rock: native silver – zincous copper – barite – anhydrite – kaolinite – laumontite (White Tiger oilfield) and sulphates of iron, aluminum, sodium and calcium – iron-aluminum alum, alunite, jarosite, mirabilite, melanterite, gypsum (deposit in the rocks of the Bazhenov formation of the Salym area). Diagnostics of secondary minerals was established based on the results of microprobe studies of undisturbed samples and analysis of the composition of water extracts from crushed core samples. The species composition of secondary minerals indicates a high temperature of the affected solutions, which varied from 600 to 200°C in the case of the White Tiger oilfield, and in the range of 350–450°C, in the case of rocks of the Bazhenov formation. Hydrothermal alteration of crystalline rocks with the formation of secondary clay minerals (kaolinite, montmorillonite, hydromica), zeolites and minerals-sulfates, which are crystalline hydrates, occurs with the absorption of huge amounts of water by the rock (up to $4 \cdot 10^8$ tons of water per 1 km³ of altered rock). This may be related to the waterlessness (lack of bottom water) of oilfields, the reservoir of which has a hydrothermal origin. It is possible that oil deposits in crystalline rocks with high oil-saturated zones have associated waters of hydrothermal rather than sedimentogenic origin, but they occur at considerable depths and are not penetrated by drilling. This possibility is evidenced by the discovery of hydrothermal water in the basement of the White Tiger reservoir at a depth of 4493 m, which, in terms of chemical composition and mineralization, is close to the waters of sodium chloride hydrotherms of Kamchatka.

Keywords: oil deposits, crystalline rocks, reservoir, hydrothermal process, bottom water, secondary minerals

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Introduction

The overwhelming majority of oil deposits in oil and gas bearing basins are underlain by formation waters, which are mainly represented by two genetic types (according to classification of V.A.Sulin): sedimentogenic calcium chloride (CC) brines and inversion sodium bicarbonate (SBC) waters, with brines sharply prevailing. It is extremely rare for formation waters of oil and gas deposits to be represented by low-mineralized waters of infiltration origin. The existence of underlying formation waters is a natural condition for the formation of oil accumulations from the point of view of sedimentary-migration theory.

However, there is a category of oil fields in which formation water has not been found, i.e. in the

development of which water was not obtained over a long period of operation in natural mode without maintaining reservoir pressure (RPM) by water injection. These deposits are few in number and the conditions of their formation are poorly understood. Such deposits include, for example, an oil deposit in clay rocks of the Bazhenov formation (BF) of the Salym area and a number of other oil fields in Western Siberia, as well as the White Tiger field in crystalline (granitoid) rocks of the basement of the South Vietnam shelf. What these fields have in common is that the reservoir is represented by hydrothermally altered zones in crystalline (White Tiger field) or clayey rocks (BF, Salym area). Also, a feature of these deposits is often high production rates (more than 1000 tons/day) of several (1–3 wells), which determine up to 90–95% of the total production of the field. So, from well 15P of the Em-Egovskoye field in Western Siberia, over 10 years of operation, more than 1 million tons of water-free oil has been produced, which

has the same procedure as the production from all other producing wells (about 100) of this field. The experience of developing similar deposits in Western Siberia made it possible to propose the term “vein reservoir” (Belkin, Medvedevskii, 1988), by analogy with hydrothermal ore veins, emphasizing their main morphological properties: a large deposit height with small transverse dimensions, i.e. very high vertical oil-bearing range (up to 1.5 km for the White Tiger field). The model of such a deposit is rather similar to the model of a vein ore deposit.

The issue of the lack of bottom waters in such fields has not been covered in the literature, so it seems useful to consider the occurrence of this feature on the example of the White Tiger field oil (shelf of South Vietnam) and of the Bazhenov formation of the Salym area in Western Siberia.

By the term «water-free oil deposits» we mean oil deposits in which free formation waters are not found, but not devoid of bound and loosely bound waters.

Geological structure of the White Tiger oil field

In 1988, at the White Tiger oil field, a large in terms of reserves (500 million tons), highly productive (well flow rates more than 1000 tons/day) was discovered in a granite massif of the basement. For the first time in the world, the presence of such large accumulations of hydrocarbons (HC) in the bedrock of the basement was established. The geological structure of this deposit is discussed in detail in numerous publications, among which one of the most comprehensive is the work (Gavrilov et al., 2010), so here we will only recall the main characteristics.

The White Tiger oil field is located in the middle part of the central uplift of the Mekong depression, the stratigraphic section of which includes the Pre-Cenozoic crystalline basement and the overlying terrigenous deposits of the Oligocene, Miocene, and Pliocene-Quaternary age. The thickness of the Cenozoic sedimentary cover varies from 3000 m on local uplifts to 8000 m in depressions. In the Paleogene, as a result of block movements of the continental lithosphere, separate structures were formed – protrusions of the crystalline basement. One of these ledges, the White Tiger, is a horst-like structure stretching in a northeastern direction in accordance with the general structural-tectonic plan of this section of the South Vietnamese shelf. In the structure of the White Tiger oil field, two structural stages are distinguished: the Pre-Cenozoic crystalline basement (Cretaceous according to the absolute age) and the Cenozoic sedimentary terrigenous complex (Figure 1).

In the sedimentary complex, oil-bearing sandstones are of the Lower Oligocene and Lower Miocene age. However, the main amount of hydrocarbons is

concentrated in fractured granitoids of the basement, which account for more than 90% of the total production.

In the first works (Dmitrievskii et al., 1990, 1992) devoted to the genesis of the reservoir in the granitoid basement of the White Tiger oil field, its hydrothermal nature was established, which was proved by the data of microprobe and X-ray diffraction studies, which revealed a complex of secondary minerals: barite in association with native silver, kaolinite, dickite, ferric chloride, zincous copper (Figure 2). In addition, calcite and laumontite were ubiquitous along cracks. The association of zincous copper and ferric chloride indicated the chloride composition and high temperature (more than 600–800°C) of the affected hydrothermal fluids. The barite-silver association indicated a temperature of 300–400 °C of hydrothermal solutions; the calcite-laumontite complex was the lowest temperature, with a formation temperature of 200–250°C. These indicator minerals made it possible to definitely establish the nature of the reservoir as hydrothermal, in contrast to the initially assumed weathering crust. Also, the identified mineral associations indicated a change in the composition of the affected hydrothermal fluids. Initially, the granite massif was worked out by high-temperature ($T = 600 - 800^{\circ}\text{C}$), low-mineralized ($M < 1.0 - 4.0 \text{ g/l}$) hydrothermal fluids of sodium chloride composition, saturated with gaseous HCl, HF and CO_2 , which were then low-temperature solutions containing mainly $\text{SO}_2 + \text{SO}_3$, H_2S and CO_2 , which is associated with a change in the composition of the endogenous fluid during its cooling (Sokolov, 1971).

It has now been established that the reservoir of the oil field is represented by fractured and hydrothermally altered granites, while the permeability of filtering fractures is 90–180 mD, with practically zero matrix permeability. The void space is characterized by cracks and leaching caverns, the morphology of which, according to the data of polished sections impregnation with a luminophore, is shown in Figure 3. In the most hydrothermally developed areas, the total porosity in some cases reached 20–35%.

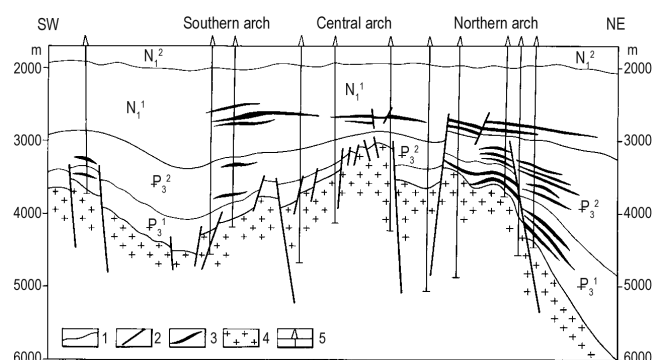


Fig. 1. Longitudinal section of the White Tiger oil field, (after (Tien, 1998) with amendments). 1 – boundaries of aquifers; 2 – faults; 3 – oil accumulations; 4 – crystalline basement rocks; 5 – drilled wells

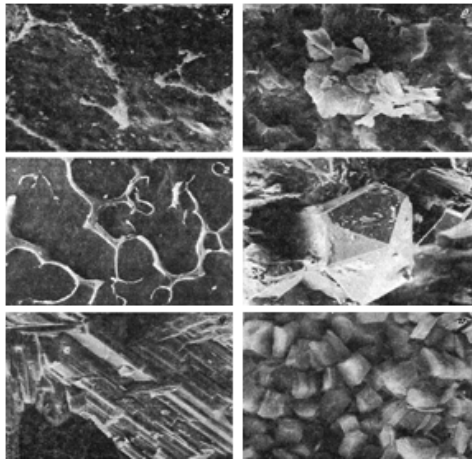


Fig. 2. Secondary hydrothermal mineralization in granites of the White Tiger oil field (Dmitrievskii et al., 1992). From left to right and from top to bottom: barite, native silver flakes, native silver on barite, quartz, laumontite, kaolinite (dickite). SEM, image magnification 1000^x

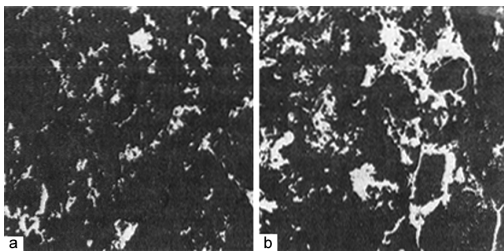


Fig. 3. The structure of the void space of hydrothermally altered rocks (Dmitrievskii et al., 1992). SEM, magn. 50^x. a – kaolinite zone: void size 0.01–0.03 mm; b – zeolite zone: cavern size up to 1.0 mm, crack opening up to 0.5 mm. Note: white – cavities filled with fluorescent material

It should be noted that according to the complex of minerals and their distribution in the void space, the hydrothermal reservoir of the White Tiger deposit is a so-called “empty” vein, when no ore body was formed in the leached space (micro-inclusions of native silver were indicated at the beginning of ore formation), but only characteristic hydrothermal zoning, in the distribution of secondary minerals and secondary porosity values. Hydrothermal zoning consists in the fact that the most leached zones are located closer to the feed channel, with quartz-barite-kaolinite association, which is then replaced by calcite-laumontite-hydromica (Volostnykh, 1972). Accordingly, the values of the secondary porosity also change, which naturally decreases to the sides of the vertical feed channel, decreasing from 20–30% to 1–5%.

The establishment of the hydrothermal genesis of the reservoir made it possible to predict the development of hydraulic permeable reservoir zones in the form of narrow (up to 1 km across) and rather deep (up to 1.5–2 km thick) “pockets” confined to faults (Figure 4). These forecasts were subsequently confirmed by geophysical studies and drilling results (Figure 5). Figure 5 shows that if in the upper part of the massif (to

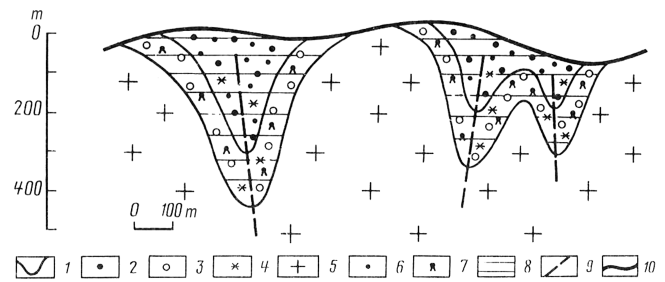


Fig. 4. Morphology of a hydrothermal reservoir in a granitoid basement according to theoretical concepts (Dmitrievskii et al., 1990). 1 – boundaries of zones of altered rocks; 2 – kaolinite zone; 3 – zeolite zone; 4 – ore polymetallic mineralization; 5 – unaltered rocks of the crystalline basement; 6 – cavernous type of void space; 7 – cavernous-fractured type of void space; 8 – oil-saturated rocks; 9 – tectonic faults; 10 – boundary of the surface of the crystalline basement rocks and the sedimentary cover

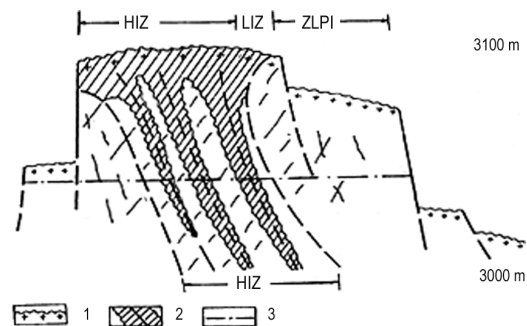


Fig. 5. The morphology of the reservoir in the granitoid basement of the White Tiger oil field according to development data (Dong, Demushkin, 1996). 1 – boundary of basement rocks and sedimentary cover; 2 – oil-saturated rocks; 3 – the depth of formation of an artificial oil-water contact (AOWC); HIZ – high inflow zone; LIZ – low inflow zone; ZLPI – zone of low probability of inflow

a depth of about 3500 m) the deposit could be considered massive, as a result of extremely strong hydrothermal development and the confluence of uncompacted zones, then below the “vein” structure clearly manifested itself in the form of deep permeable “pockets” the depth of which was several times greater than the width. These “pockets” were located along the faults, separated by practically impermeable granitoids.

Chemical composition and genesis of water in the basement of the White Tiger oil field

A distinctive feature of oil deposits in the granite massif of the White Tiger field is its almost complete absence of water. This productive reservoir has been in operation for more than 30 years, however, no inflows of formation water have been received, despite the fact that the wells were drilled to a depth of 5014 m, and the basement penetration exceeded 1500 m. Even at these levels, there is no bottom water, i.e., oil-water contact is not established. An exception is one case of

obtaining mineralized associated water at a depth of 4493 m from well 110 (Figure 1) of the Northern arch in an isolated block of the basement, where ocean water used for reservoir pressure maintenance did not enter. It is of interest to note that the temperature at the sampling depth was 165°C, which exceeded the usually recorded values at this depth by 15°C.

In all respects, this water sharply differed, both from the formation waters of overlying sedimentary complexes, and from the oceanic water pumped into the wells of the field for reservoir pressure maintenance. A detailed analysis of the chemical composition and origin of water in the basement of the White Tiger field was first presented in (Kireeva, 2010) and cited in (Kireeva, 2018); however, it seems necessary here to briefly repeat the evidence of its genesis, since the mentioned isolated publications are little known.

The total mineralization (M_{tot}) of the “reservoir” water of the basement of the Northern arch is on average 5.1 g/l, which is approximately 7 times less than the M_{tot} of ocean water (Table 1). The waters of the sedimentary cover have a similar low mineralization, however, in terms of the component composition, the basement water differs significantly from them. The basement water is almost “pure” chloride-sodium-calcium, the content of Cl-ion in all samples exceeds 95–96 eq % (Table 1), the content of HCO_3^- and SO_4^{2-} -ions does not exceed 1.0–2.5 eq %. In the formation waters of the Oligocene and Lower Miocene, the content of hydrocarbonate and sulfate ions increases sharply (more than 10 times), with a corresponding decrease in the content of chlorine ion. The genetic coefficient rNa/rCl for basement water varies within 0.88–0.90, and according to the classification of

V.A. Sulin, they should be classified as HC type, i.e. represent metamorphosed sedimentary waters. However, in this case, the M_{tot} of water in the basement of the White Tiger field is approximately 10 times less than the mineralization of “typical” brines of the CC type of deep horizons of the sedimentary cover. The natural change with depth in the composition and salinity of buried waters (metamorphism of groundwater) suggests a simultaneous increase in M_{tot} with an increase in the relative proportion of NaCl in the composition of the salt complex. In this case, the value of the NaCl content in an amount of about 86–96 eq % should correspond to the value of M_{tot} not less than 45–60 g/l (Krainov et al., 2004). Thus, the observed waters of the basement of the White Tiger field cannot be considered as buried sedimentary waters.

It remains to assume that these waters are buried hydrothermal waters, “remnants” of those waters that flowed through tectonic cracks into the granite massif and due to the leaching effect of which the reservoir was formed. Indeed, in all its characteristics, this water is very close to the high-temperature sodium chloride hydrothermal fluids of Kamchatka (Table 1) The hydrothermal nature of these waters is indicated, first of all, by the anomalously high boron content (165 mg/l) with such a low mineralization (5.1 g/l) and a high B/Br ratio of 20.4 (Table 1). Such high values of the B/Br ratio are typical for modern hydrothermal fluids, and for seawater and sedimentogenic brines, this coefficient is 0.1–0.3 (Kireeva, 2009).

The discovery of waters of hydrothermal genesis in direct contact with the basement oil reservoir in the complete absence of sedimentary waters casts doubt on

Components (mg/l) and parameters of chemical composition	Ocean water	White Tiger oil field, Northern arch, Lower Oligocene*	White Tiger oil field, basement, well 110*	Sodium chloride hydrotherms of Kamchatka**
Na+K	12180	992	1700	555.9
Mg	1250	1.7	9	4
Ca	400	113	294	13.4
Cl	18700	1218	2945	886.8
Br	65	12.4	7.6	4.6
I	0.05	1.4	2.1	
NH ₄		13.5	5.4	5
SO ₄	2500	243	84	39.4
B	4.6	10.5	147.2	152
HCO ₃	130	565	85	54.9
M_{tot} , g/l	35.1	3.2	5.1	2.1
rNa/rCl	0.88	1.3	0.89	1.02
B/Br	0.1	0.85	20.4	33.0
Formula of ion composition	$\frac{Cl}{(Na+K)} 91 \frac{SO_4}{Ca} 8 \frac{HCO_3}{Mg} 1$	$\frac{Cl}{(Na+K)} 70 \frac{HCO_3}{Ca} 19 \frac{SO_4}{Mg} 11$	$\frac{Cl}{Na} 96 \frac{SO_4}{Ca} 3 \frac{HCO_3}{Mg} 1$	$\frac{Cl}{(Na+K)} 94 \frac{SO_4}{Ca} 3 \frac{HCO_3}{Mg} 3$
Water type according to classification of V.A.Sulin	Magnesium chloride	Sodium bicarbonate	Calcium chloride	Sodium sulfate

Table 1. Chemical composition of groundwater from the White Tiger oil field, Kamchatka hydrothermal waters and ocean water. Note: * – content of components according to (Tien, 1998), ** – content of components according to (Arsanova, 1974)

the formation of the reservoir in the basement as a result of vertical downward or lateral migration of “micro-oil” from the source rocks of the sedimentary cover. Indeed, the movement of hydrocarbons from sedimentary rocks should inevitably be accompanied by the movement of associated sedimentary waters, which is not observed in reality.

Reservoir in clayey rocks of the Bazhenov formation

High-bituminous rocks of the Bazhenov formation, Jurassic, and the facies close to it Tutleim are distributed in the central, western and southern regions of the West Siberian oil and gas province on an area of about 800 000 km². The formation thickness ranges from 10 to 50 m, reaching maximum values in the Salym region. The BF rocks, which are both a regional aquiclude and a regional oil source stratum, are underlain and overlain by clay units over a larger area of their distribution, which isolate it from sandy reservoirs and create a closed system with abnormal pressure in it. One of the features of the BF rocks is a high organic matter (OM) content – 5–20%, which is an order of magnitude higher than in the surrounding rocks. In lithological terms, BF rocks are represented by argillaceous, argillaceous-siliceous and carbonate-argillaceous varieties. Structurally, two varieties are distinguished: dense clays of massive constitution and loose, thin-layered (thin-leaved) rocks, named by I.I. Nesterov “bazhenites”, which are the collector. During the entire period of development of Bazhenov formation, nowhere in the wells was a water-saturated or water-oil zone of the formation encountered, and most (75–80%) samples of BF rocks are hydrophobic.

The study of BF rocks on a microprobe (Kireeva, 2011) revealed in them a whole complex of secondary minerals, represented mainly by sulfates: iron-aluminum alum (Fe, Al)₂(SO₄)₃·13H₂O (Figure 6), alunite K₂SO₄·10H₂O or its ferrous analogue – jarosite (K, Fe)SO₄·12H₂O, mirabilite Na₂SO₄·10H₂O, iron sulfate – FeSO₄·7H₂O, gypsum CaSO₄·2H₂O (Figure 7). There were also crystals of native sulfur. The overwhelming majority of secondary sulfate minerals were found in loose varieties (“bazhenites”), but they were also found in rocks of massive constitution. In “bazhenites”, the intensity of sulfate mineralization was more than an order of magnitude higher than its content in massive rocks, and the total amount of water-soluble sulfate salts reached 10–11%.

It should be clarified that samples for microprobe studies and the preparation of water extracts were taken from the inner parts of the core in order to exclude the effect of surface weathering. However, in the work (Kireeva, Kazak, 2017) it was proved that surface low-temperature processes (wetting and drying in



Fig. 6. Left to right: Hair-like crystals of iron-aluminum alum in the rocks of Bazhenov formation, magn. 300^x. Fragment of the previous image, magn. 1000^x. Energy-dispersive spectrum of crystals of iron-aluminum alum: Al, S, Fe

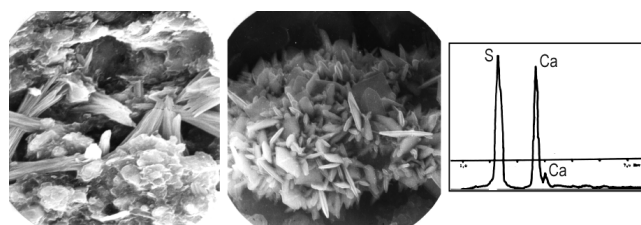


Fig. 7. Left to right: Gypsum crystals in the fracture of the Bazhenov formation rock, magn. 300^x. Gypsum crystal unit, magn. 300^x; Energy-dispersive spectrum of gypsum crystals: S, Ca

atmospheric conditions) cannot lead to a significant change in the massive lithotypes of BF rocks with their transformation into foliated varieties and the formation of secondary sulfate minerals due to oxidation of pyrite contained in the rocks.

In works (Kireeva, 2011; Kireeva, Kazak, 2017), it was proved that secondary sulfate mineralization, found according to the data of water extracts and microprobe analysis, is the result of the development of the rock with high-temperature (350–450°C) water vapor saturated with sulfurous (SO₂) and sulfuric (SO₃) gases. Here are the main substantiations of the hydrothermal nature of sulfate mineralization. These sulfate minerals are not formed in the reducing environment of marine conditions, therefore, they could not have arisen at the stage of formation of the BF rock. Secondary sulfate mineralization of BF rocks is in no way connected with modern reservoir temperatures and with the depth of occurrence; therefore, it is impossible to explain its occurrence by the influence of “resurgent” waters, i.e. the transition of waters from a bound state to a free state in the process of catagenesis. However, a similar complex of sulfate minerals is characteristic of hydrothermally altered clay rocks in areas of modern volcanism. In addition, it was noted that rocks containing secondary sulfate mineralization are localized at the bottom of the section, and also tend to be located in the sub-latitudinal region, in zones adjacent to long-lived basement faults.

Sulfuric acid development of some BF rocks, accompanied by the removal of Ca, Mg, Na, Al cations with simultaneous accumulation of Fe sulfates, led to the formation of a reservoir in Bazhenov formation,

with an increase in effective porosity from practically zero values to 11–22%. This followed from the data of cathodoluminescence studies (study of polished sections impregnated with luminophore material) on SEM, which showed that the reservoir properties of the Bazhenov rocks are associated with cracks and caverns, opening up to 0.1 mm, “loosely” filled with secondary sulfates (Figure 8).

The data obtained on acid leaching and secondary hydrothermal mineralization in BF rocks allow us to assert that the formation of a reservoir in tight clay rocks is possible only as a result of external action of aggressive high-temperature fluids, and not as a result of internal rock reserves (structural reorganization of clay minerals and oil formation processes).

When a reservoir appeared in clayey rocks of BF, crystals of secondary minerals had a “swelling” effect, not allowing cracks to close, which are usually not preserved in clay rocks.

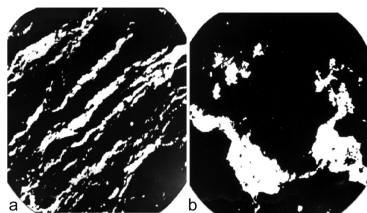


Fig. 8. The morphology of the void space in the “bazhenites”: a) numerous cracks along the bedding, magnification 50^x; b) leaching caverns, magn. 50^x. Note: white – cavities filled with fluorescent material

Possible cause of waterlessness in oil deposits

Common in the two considered cases of anhydrous oil deposits is the formation of a reservoir as a result of hydrothermal action, i.e. the reservoir zones were formed as a result of leaching of dense, initially substantially impermeable rocks with high-temperature solutions. As a result, a reservoir was formed, the void space of which is characterized by a complex system of caverns and leaching cracks, partially filled with secondary minerals, in an almost impermeable matrix.

The temperature of the influencing fluid is recorded by the complex of secondary minerals that fill the leached zones, because the composition of the resulting hydrothermal minerals is determined primarily by the temperature of the incoming solution, and not by the composition of the converted rocks. Thus, solutions with a temperature of 400–600°C correspond to ore mineralization, often containing chlorides; solutions with a temperature of 200–400°C correspond to kaolinite-quartz-barite-alunite mineralization; solutions with a temperature of 200–300°C correspond to montmorillonite-hydromica-calcite-laumontite association. Probably, it is precisely the effect of high-

temperature solutions that is associated with the dryness of the formed reservoir.

It is known (Volostnykh, 1974) that argillization of primary silicates, i.e. formation of secondary clay minerals (kaolinite, hydromica, montmorillonite), a huge amount of water is consumed: up to $2 \cdot 10^8$ tons of water per 1 km³ of kaolinized rock, and 2 times more in the case of the formation of secondary montmorillonite. Fissures and caverns in the basement hydrothermal reservoir of the White Tiger oil field are filled with the calcite-laumontite-kaolinite mineral association, the formation of which required a large amount of water. We emphasize that secondary clay minerals of the basement of the White Tiger field are represented not only by kaolinite, but also by mixed-layer minerals of the hydromica-montmorillonite type, which, in addition to OH groups, also contain water molecules in the interlayer spaces. In addition, a mineral such as laumontite, the content of which in the granitoid reservoir of the White Tiger field is very significant (Shnip, Dzyublo, 2019), also contains water molecules in the crystal cavities.

In the case of hydrothermal development of BF rocks, sulfates of iron, aluminum, sodium and calcium were formed: iron-aluminum alum – $(\text{Fe}, \text{Al})_2(\text{SO}_4)_3 \cdot 13\text{H}_2\text{O}$; alunite – $\text{K}_2\text{SO}_4 \cdot 10\text{H}_2\text{O}$; jarosite – $(\text{K}, \text{Fe})\text{SO}_4 \cdot 12\text{H}_2\text{O}$; mirabilite – $\text{Na}_2\text{SO}_4 \cdot 10\text{H}_2\text{O}$; iron sulfate – $\text{FeSO}_4 \cdot 7\text{H}_2\text{O}$; gypsum – $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$. All these minerals are crystalline hydrates containing from 2 to 13 water molecules. Consequently, the formation of the hydrothermal reservoir in the BF rocks also took place with the absorption of a significant amount of water.

The absence of formation waters of sedimentogenic origin can also be explained by the flow of oil into the reservoir together with the supplied endogenous, rather than squeezed out pore (sedimentogenic) waters, which was substantiated in (Kireeva, 2018).

However, it is not excluded that in the case of the White Tiger field, the associated waters did exist, but they were simply not penetrated by drilling. The possible existence of underlying waters, of hydrothermal rather than sedimentogenic origin, is indicated by the discovery of hydrothermal waters in an isolated block of the basement of the field. The formation of an artificial oil-water contact (AOWC) at depths of 3800–4500 m could lead to the cutting off of natural OWC zones, i.e. zones of contact between oil and underlying salt water of hydrothermal genesis. Recall that hydrothermal water in the well 110 was received at a depth of 4493 m.

In the case of oil accumulations in the rocks of the Bazhenov formation of the Salym area, it is likely that all the water was absorbed by the rock, because the thickness of Bazhenov formation in this area does not exceed 50 m.

Thus, the waterlessness of some oil deposits confined to “unconventional” reservoirs, i.e. to rocks,

the porosity of which was formed as a result of intense leaching effects of high-temperature fluids, is a natural consequence of their formation – the incoming high-temperature water is absorbed by the rock.

We emphasize that the goal of the article was only a possible explanation of the existence of waterless oil deposits, without carrying out balance calculations of the amount of water that could be absorbed by the rock during the formation of secondary minerals (kaolinite, laumontite, etc.). Such a calculation is possible, but requires data on the exact quantitative content of secondary “water” minerals per unit volume of the reservoir, which the author does not have.

Conclusion

Consideration of two oil fields with the absence of underlying formation waters allows us to conclude that the formation of a reservoir as a result of the leaching effect of high-temperature fluids is common.

In both cases, a complex of minerals of clearly hydrothermal origin was found in the cracks and caverns of the reservoir: native silver – barite – anhydrite – kaolinite – laumontite (White Tiger oil field) and sulfates of iron, aluminum, sodium and calcium (oil field of the Bazhenov formation at the Salym area).

By the species composition of secondary minerals, it is possible to determine the temperature of the affected solutions, which varied from 600 to 200°C in the case of the White Tiger oil field, and in the range of 350–450°C in the case of BF rocks.

Hydrothermal alteration of crystalline rocks with the formation of secondary clay minerals, zeolites and minerals-crystalline hydrates occurs with the absorption of huge amounts of incoming water by the rock (up to $4 \cdot 10^8$ tons of water per 1 km^3 of altered rock). Perhaps this is the reason for the waterlessness (absence of free gravitational waters) of oil fields, the reservoir of which is of hydrothermal origin.

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