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Transformation of deep fluid flow in the process of oil and gas field formation of north Western Siberia

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Abstract. Since the discovery of giant hydrocarbon fields in the north of Western Siberia, no unified concept regarding the mechanism and stages of their formation has been developed. This paper on the example of the Urengoy field demonstrates that the formation of hydrocarbon accumulations from Jurassic to Cenomanian is related to hydrocarbon fluids flowing upwards from the deep depth and their subsequent transformation. In the sedimentation process, the gases of the secondary kerogen destruction form an upward fluid flow, which dissolves oil components from source rocks and carry them to shallower depths. The formation waters of the north Western Siberia are methane-saturated; so, due to changes in its solubility during the Neogene uplift, methane comes out into a free phase. The calculations were performed on the upward flow phase separation and oil and gas content changes in reservoirs with depth. The addition of 50 mole % of methane released from the water to the Neocomian reservoirs gives a good agreement on the C_1-C_4 components and the C_{5+} content in the formation gas. The calculations were based on the proposition that methane captures light fractions from oil rims, thus increasing oil density. At shallow depths, the hydrocarbons are biodegraded, which leads to formation of almost pure methane accumulations in the Cenomanian reservoirs. The main mechanism of the upward flow transformations, controlling the oil and gas accumulation, is phase transitions. The additional factors, like methane dissolution in water and its transition into a free phase, microbial converting of hydrocarbons assure consistency between the calculated formation fluid properties and the actual data in the entire sedimentary section.

Keywords: deep fluids, phase transitions, condensation mechanism, primary migration, hydrocarbon field formation, methane dissolution, Western Siberia, Urengoy field

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Introduction

For the last 50 years, the formation of oil and gas fields of the north Western Siberia aroused a heightened interest. The primary focus was on determining a source to charge the giant Cenomanian gas reservoirs (Prasolov, 1990; Nemchenko et al., 1999; Littke et al., 1999; Milkov, 2010; Fjellanger et al., 2010). The formation mechanism of hydrocarbon accumulations was not considered for the entire sedimentary section from Jurassic to Cenomanian. In work (Batalin et al., 2017), the oil and gas field formation was explained by a condensation mechanism, consisting in the phase separation of the fluid flow, coming from very deep zones. The basic assumption is that in the main gas generation phase a large volume of gases creates an abnormally high pore pressure, which leads to microfracturing and possibility of primary migration through the fracture network. The generated gases dissolve the dispersed petroleum hydrocarbons of source rocks. As a result, an upward hydrocarbon flow transports oil components to shallower zones, where a pressure drop leads to condensation of a liquid with properties corresponding to real oil. First, fields with a small oil rim are formed. Then, after the condensation of new oil portions, its size grows. At some moment, the oil is pushed out of a trap and begins an independent migration, guided by the regional seal geometry. The condensation mechanism is proposed to be the main method for the formation of hydrocarbon accumulations, which leads to the formation of hydrocarbon accumulations. The model predicts a change in the physicochemical characteristics of reservoir fluids over a large depth interval of sedimentary section. The calculations performed on the example of the multi layered Urengoy field showed a good match in fractional composition of oil and condensate in density and molecular weight, which confirmed the condensation mechanism of the field formation.

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At the same time, there was a discrepancy in the calculated content of gas components (C_1-C_4) in reservoir fluids. The reason is presumably related to the fact that some important processes in the formation of oil and gas accumulations was not taken into account. Therefore, the work is targeted to identify all key factors controlling transformations of the hydrocarbon upward flow and formation of the accumulations in the north Western Siberia in the interval from Jurassic to Cenomanian; and to determine the way of their accounting in the processes under consideration.

Upflow Phase Differentiation

The main source for the fields in the north of Western Siberia is hydrocarbons, which migrated upwards from deep zones. Representatives of all petroleum geology schools agree with this statement (Prasolov, 1990; Fjellanger et al., 2010; Dmitrievsky, 2008; Dmitrievsky et al., 2008; Punanova, 2018). Hydrocarbons generated from the organic matter of the Pokur source rocks, at 1.1-1.8 km, are of the secondary importance. In the Urengoy region, the gas flow formed by the secondary destruction occurs at a depth of 5-6 km (Batalin et al., 2017). When moving upward, it captures petroleum hydrocarbons from the source rocks. As isotopic studies show the source rocks in the north Western Siberia are referred to the Tyumen Formation and, in a less degree, to the Bazhenov Formation (Liu et al., 2016). The dissolution of petroleum hydrocarbons by gas and their further transportation by the upward flow are confirmed by the research on bitumen distribution in the Bazhenov Formation (3783-3844 m) in the Tyumen ultra-deep well (SG-6) (Sirotenko et al., 2002), which noted that the oil components were carried over by gas from tight to permeable zones, from the formation base towards its top.

Under high pressures, the hydrocarbon fluids are in a single-phase state in the form of gases saturated with heavy components. When moving upward, the pressure decreases and the condensation takes place. On the migration path, the heaviest components in the form of microdrops are the first separated into a liquid phase. So, at a depth of 6.0-6.3 km, a carbonaceous-bitumen mass is observed in an intergranular space and epibitum in the fractures (content of chloroform bitumen B_{chl} is 0.004 %); at a depth of 5.6-6.0 km bitumen is noted in the intergranular space; and at a depth of 4.7-5.3 km the intergranular space contains the oil-resinous migrated bitumen (B_{chl} from 0.02 to 0.08 %) (Frick et al., 2009). The content of migrated bitumen increases when depth decreases. At the same time, as SG-7 (En-Yakhinskaya ultra-deep well) core showed, at a depth of 5.6-6.2 km the asphaltene and resin fraction in the bitumen is 55-60 %, at a depth of 3.8-5.2 km their fraction drops to 30-35 % (Frick, 2009). As is known, during the kerogen destruction, substances with decreasing molecular weight are successively obtained. Here the opposite situation is observed. Therefore, these bitumens with a large amount of asphaltenes and resins at the great depth were formed during the migration process by condensation from the fluid flow, due to the asphaltene and resin sorption on the rock surface, and due to fact that the asphalt-resin aggregates simply got stuck in the pore throats due to their size.

At some moment, so much fluid condenses from the flow that the accumulation can be formed. The deepest oil reservoirs were discovered in the Jurassic. However, most of oil condenses from a dramatic pressure drop when thick cap rocks break through. In the north of Western Siberia, the Upper Jurassic-Lower Cretaceous regional seal is at a depth of 3-4 km. After its breakthrough, a hydrocarbon flow filled the vertically adjacent reservoirs (BU_{14}-BU_8). After that, within theses reservoirs, a gravitational segregation took place. Gas occupied the upper part of the traps and the liquid formed oil rims. After that, gas of the gas caps migrated through the seal into the overlying traps (Batalin et al., 2008). As the depth decreases, the upward flow composition gradually became lighter due to condensation of the heaviest C_{5+} fraction.

Based on these assumptions, we calculated the change in hydrocarbon composition of the accumulations. To simplify the task, we combined the adjacent Urengoy formations with the same-depth gas-oil contact. Thus, we get the "combined" reservoirs G_0 ... G_8 (Table 1). The phase transformations were calculated using the Peng-Robinson equation of state; as the initial composition, the G_8 actual gas condensate composition (depth 3650 m) was taken. The calculation results compared to actual data (Gritsenko, 1983) are shown in Table 1 and in Fig. 1.

The Table shows that as the depth decreases, the methane content increases, and the C_2-C_{5+} fractions decreases. In reality, however, the methane content is higher (in comparison with calculated, which requires explanation.

Additional factors of flow transformations

The increased methane content can be explained by the additional input from other sources. So, in work (Littke et al., 1999) the increase of methane content in the Cenomanian reservoirs is explained by its release from formation water. The formation waters of the north Western Siberia are extremely saturated with methane; therefore, during the Neogene uplift due to a change in solubility, it was released into a free phase. In order to prove this assumption, for each component from C_1, ... C_4 the volume of methane, which should be added into the system to match the computed and actual data, was calculated. The results are shown in Fig. 2a. The Figure shows that at a given depth for all C_1, ... C_4 considered

Combined reservoir	Reservoir	Depth, m	C_1 (mol.%)		C_2 (mol.%)		C_3 (mol.%)		C_4 (mol.%)		C_{5+} (mol.%)	
			Calcu-lation	Actual data	Calcu-lation	Actual data	Calcu-lation	Actual data	Calcu-lation	Calcu-lation	Calcul ation	Calcu-lation
G_0	PK $_{21}$	1800	83,30	93,76	8,52	3,5	3,50	0,18	1,44	0,28	2,25	1,34
G_1	AU $_{9-10}$	2100	82,64	-	8,54	-	3,56	-	1,49	-	2,79	-
G_2	BU $_{1-2}$	2300	82,22	89	8,55	5,15	3,59	2,33	1,51	1,08	3,16	1,44
G_3	BU $_{5-6}$	2450	81,84	88,24	8,56	5,53	3,61	2,56	1,53	1,08	3,49	2,2
G_4	BU $_{8}^{0}$, BU $_{8}$, BU $_{9}$	2620	81,49	87,26	8,56	5,30	3,64	2,23	1,55	0,95	3,80	3,48
G_5	BU $_{10}$, BU $_{10}^{0}$, BU $_{11}$	2750	81,37	86,24	8,57	5,32	3,64	2,58	1,55	1,15	3,90	3,87
G_6	BU $_{12}$	2850	81,24	86,2	8,57	5,74	3,65	2,33	1,56	0,99	4,02	2,81
G_7	BU $_{13}$, BU $_{14}$	3000	80,97	81,61	8,57	6,86	3,66	3,19	1,57	1,33	4,26	6,19
G_8	Ach $_{3-4}$, Ach $_{5}$	3650	78,35	78,35	8,60	8,60	3,80	3,80	1,68	1,68	6,66	6,66

Table 1. Gas composition of Urengoy reservoirs G_0 ... G_8

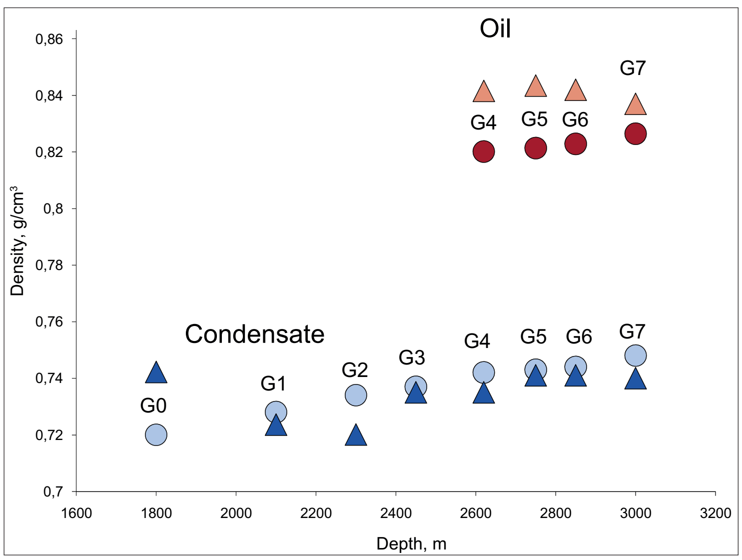

Fig. 1. The density (under standard conditions) of oil and gas condensate for deposits located at different depths. Red symbols – oil, blue – condensate; triangles – actual data (averaged), circles – calculated results.

components, almost the same amount of methane is added (about 40-60 % for 2300-2850 m), which proves the correctness of the initial assumption. The obtained additional methane volumes were averaged over all components, then the result was replaced by a linear correlation in the depth range of 2300-2850 m and by the average value at 3000 m (when averaging, the C_2, C_3, C_4 components were weighted by one, C_1 was weighted by three). The results of calculations are presented in Fig. 2b. The added methane volume averaged this way is 43-58 % in the interval 2300-2850 m and 10 % at the depth of 3000 m. The added volumes decrease with depth (Fig. 2b).

The calculated additional volumes of methane correlate with the oil density variation with depth in the oil rims. The added to the system methane dissolves light fractions of oil (reservoirs G_4-G_7), so the oil density increases. At a depth of 3000 m, the amount of added methane is small (Fig. 2b), so the difference between the calculated and actual oil density is small (Fig. 1). At a depth of 2620-2850 m, the more methane was delivered additionally, accordingly the oil density difference increases. The relationship between the loss of light oil fractions and increase in oil density is illustrated in Fig. 3. As a result, the boiling point of the BU_{14} oil (belongs to the G7 reservoir group) is 70°C, its density is 0.8370 g/cm^3. The BU11 oil (G_5 reservoir group) has no light fractions (its boiling begins at a temperature of 138°C) and, respectfully, the oil density increases up to 0.858 g/cm^3. Fig. 4 shows the calculated content of C_1-C_4 components in gas accumulations at different depths, accounting for the additional methane.

When calculating the C_{5+} components in gas, it was assumed that the additional methane first lowers the C_{5+} content in the mixture. Further, if there is an oil rim in the reservoir, the C_{5+} oil components from the rim dissolve in the methane arrived and, as a result, in the oil-rim reservoirs (G_4-G_7 reservoir, depth 2620-3000 m), the C_{5+}

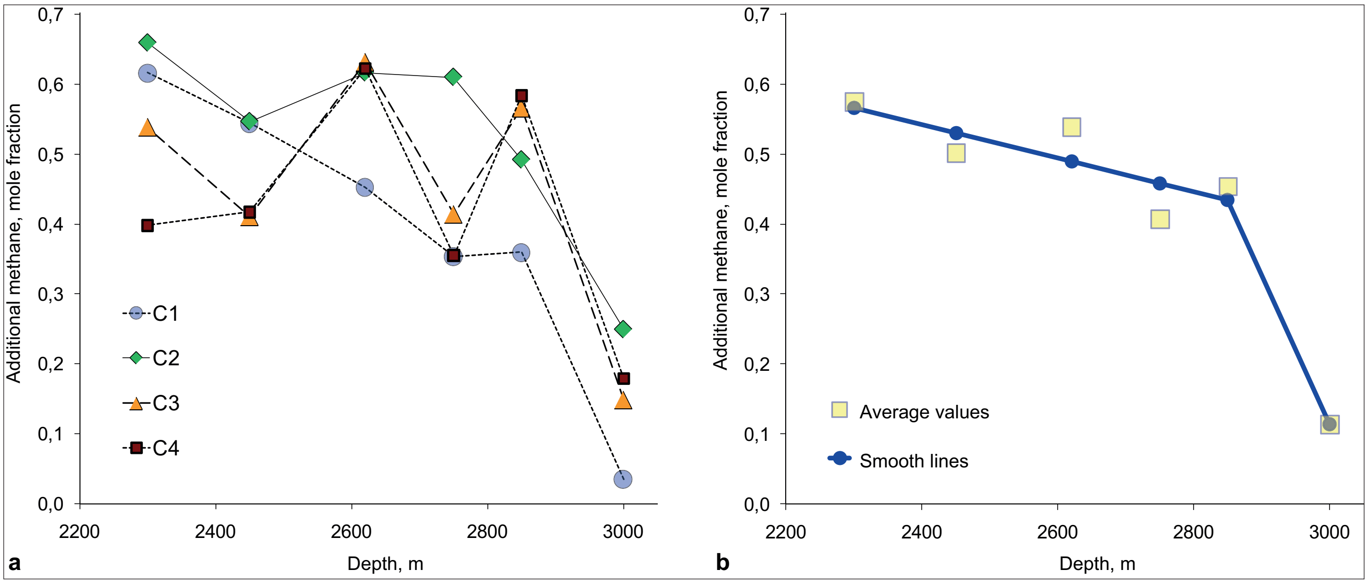

Fig. 2. The calculated volumes of additional methane came into the system from an external source. The calculations are based on the content of C_1, ... C_4 in the gas reservoirs (a). Average values and smooth lines (b).

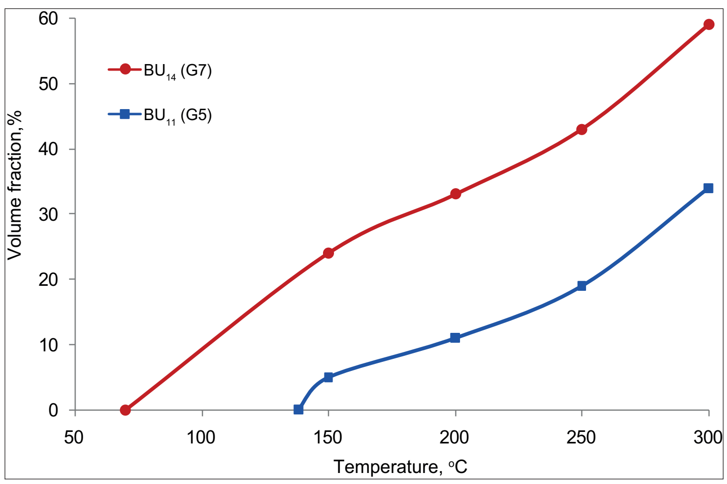

Fig. 3. Oil distillation curves for BU_{14} (belongs to G_7) and BU_{11} (belongs to G_5)

fraction in gas remains unchanged – the same as before the additional methane delivery. At shallow section, the C_{5+} fraction in the gas decreases since there are no oil rims here. The calculated C_{5+} content is shown in Fig. 5.

From Fig. 4 and 5 it can be concluded that the calculation results closely corresponds to the actual data in the interval 2300-3000 m.

In the work (Littke et al., 1999) it was assumed that methane-saturated waters came to the north Western Siberia from the Middle Ob region. However, based on geological and geochemical data such assumption was disputed (Murris, 2001). The existence of upward hydrocarbon flow over a long period of time gives reason to predicate that formation waters were methane saturated before the Neogene uplift due to good methane solubility in water.

At a depth of 1800 m, the C_2, C_3, and C_4 share is much lower than the calculated value (Fig. 4). Here, a small volume of C_{2+} components is associated with the intensive microbial hydrocarbon conversion to methane, typical for the Western Siberia fields at a depth down to 1800 m (Milkov, 2010), which ultimately leads to the formation of almost pure methane fields in the Cenomanian rocks.

Conclusion

The main mechanism of the hydrocarbon upflow transformation is related to the phase transformations. Besides that, other factors also should be taken into account. It was shown that methane, escaped from water, was added the Neocomian accumulations: in the depth interval of 2300-2850 m – in a volume about 50 mol %, in the interval of 3000 – 10 mol %. Methane washes out the light oil fractions (in reservoirs with an oil rim), by that increasing oil density. The bacterial transformation of hydrocarbons leads to the formation of almost pure methane accumulations in the Cenomanian.

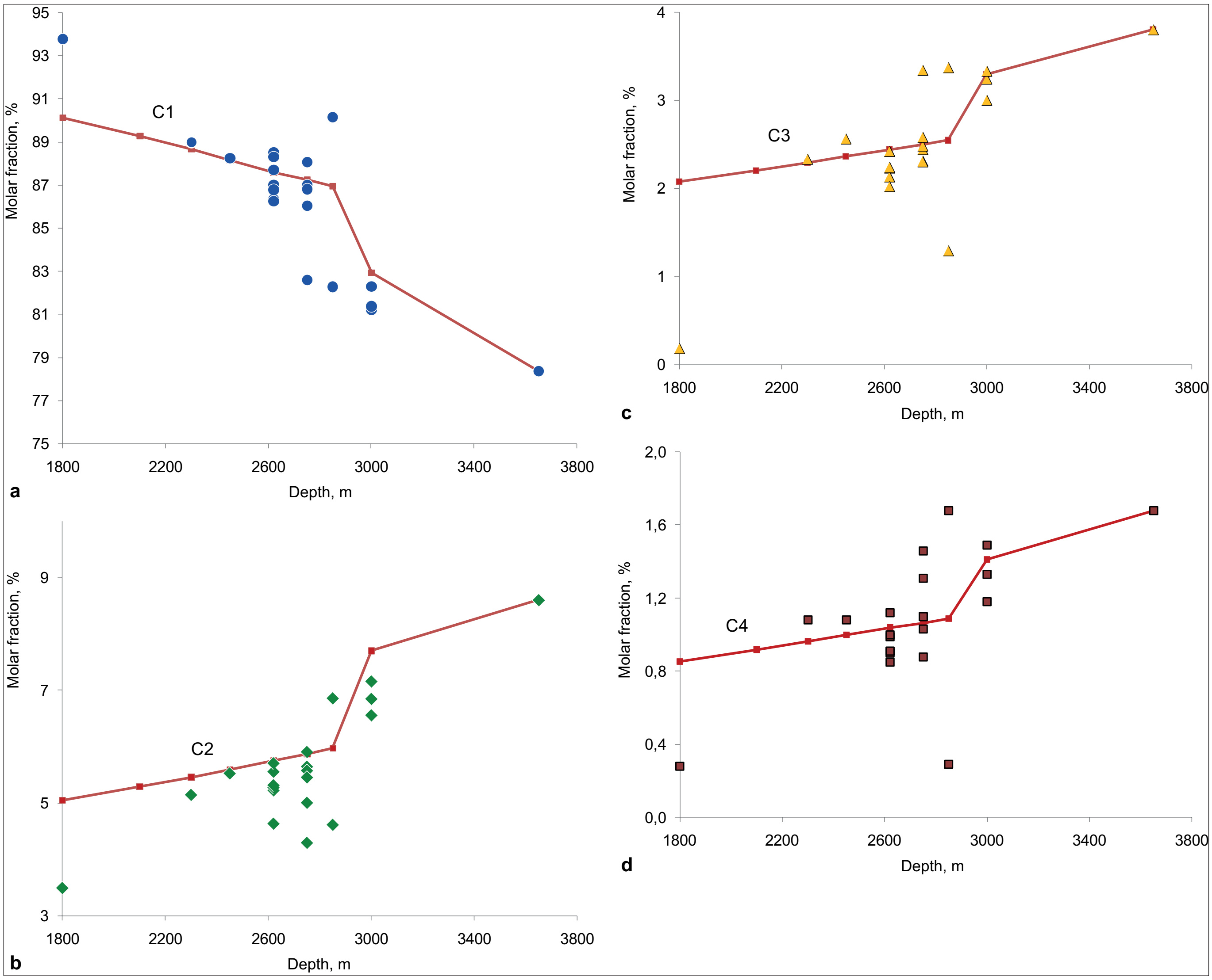

Fig. 4. Content of C_1, ... C_4 in the gas reservoirs at different depths. Symbols – actual data: C_1 (a), C_2 (b), C_3 (c), C_4 (d). The curves are the results of calculation.

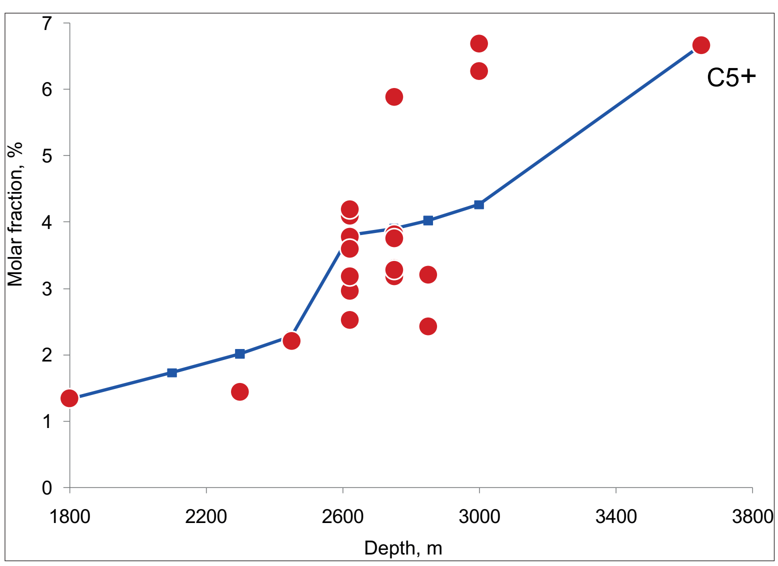

Fig. 5. The content of C_{5+} in reservoirs at different depths. Circles are actual data, curve is the calculated results.

It was shown that considering the additional factors, such as methane escape from water during the Neogene uplift, microbial conversion of hydrocarbons at a depth of less than 1800 m provides a good fit of the calculated physical-chemical properties of reservoir fluids and actual data through the entire sedimentary section.

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