DOI 10.1007/s10553-019-01017-5
Chemistry and Technology of Fuels and Oils, Vol. 55, No.2, May, 2019 (Russian Original No.2, March – April, 2019)

USE OF DISPERSED SOLID MATTER OF BAZHENOV FORMATION FOR DEVELOPING LIGHT OIL RESERVES

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Under the conditions of the low-permeable Tyumen Formation, associated petroleum gas (APG) and intrastratal air transformation product are similar in oil-displacing properties. A new approach to the development of oil reserves of the Tyumen and Bazhenov Formations is proposed. It lies in the fact that, when solid organic matter of the Bazhenov Formation dispersed in the rock mass is oxidized, air, rather than oil, should be transformed into an inert gaseous agent. At the same time, artificial fractures will be formed if the rock of the Bazhenov Formation is heated unevenly.
Key words: *intrastratal transformation, air, oil, oxidation, porous medium.*

Depletion of traditional oil reserves is stimulating interest in development of hydrocarbon resources of tight (shaley) reservoirs. In this paper, we discuss the search for new ways of oil recovery from shale and low-permeable reservoirs on the example of reservoirs of the Bazhenov and Tyumen Formations. The shale-bearing Bazhenov Formation is the cover for the Tyumen Formation, which belongs to tight clayey reservoirs. For developing shale hydrocarbon reserves of the Bazhenov Formation, it is essential to create artificial porosity, for which hydraulic and thermal fracking of the stratified reservoir is used. It can be expected that fractures are formed due to uneven thermal expansion of the rock, oil, water, and gas in closed pores, and

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the pressure in them rises to the rock cracking pressure. After cooling, the formed cracks will not close fully, i.e., artificial porosity will persist further.

For oil recovery from low-permeable reservoirs of the Tyumen Formation, the following design and technological solutions are proposed: drilling of directional slant injection and horizontal wellbores, hydrofracturing and multiple fracturing of formations with due regard for the direction of the fractures and stresses in the reservoir; use of drastic flooding schemes with high injection pressures. But design solutions assume low oil recovery factor (ORF) (about 10-30%, average 20%), i.e., the major amount of the oil remains in the reservoir. Even such a rated ORF will be hard to achieve because of fast flooding of the wells after hydrofracking (HF) or multiple hydrofracking (MHF) and of economic considerations (for profitability of recovery in conditions of West Siberia, high well production rate is essential). Application of gas methods of oil recovery is promising.

In conditions of tight and shaley reservoirs, application of mixing gas action reduces or eliminates the major forces that impede oil and fluid flow. When water is used (flooding), the interphase tension is very high (about 30-50 mN/m), whereas in the case of gas mixing oil displacement, the interphase tension is nil. Resistance to fluid movement is high in low-permeability tight reservoirs, which may make it difficult to inject water into the reservoir and to develop oil reserves.

For oil recovery from tight reservoirs, it is better to use a chemically inert gas which does not affect rock permeability adversely. Air or associated petroleum gas (APG) is suitable for West Siberian oil deposit conditions. Air, because of intrastratal transformation (oxidative processes), may pass quickly into an inert fluid consisting mainly of nitrogen, carbon dioxide, and light hydrocarbons which evaporate from the oil to the gas phase (the results of oil oxidation studies are generalized in [1, 2]). Intrastratal air transformation is accompanied in oil reservoirs by partial oxidation of the oil [3, 4]. However, if the oxidative process is implemented in the Bazhenov Formation where the main most easily oxidizable substrate is solid organic matter, which is oxidized more easily and quickly than oil, the oil loss can be reduced by producing an inert gaseous agent.

Water, even at high temperatures (typical for Tyumen and Bazhenov Formations), causes swelling and/or dispersion of clay minerals present in the reservoir, which may reduce the intake rate of injection wells, as in the case of the Bazhenov Formation [5]. For recovery of Tyumen oil, the method of oil displacement by gas (product of intrastratal transformation of air or APG), instead of flooding, can be recommended. But there arises the problem of raising the level of light oil and "sufficiently dry" gas miscibility. The data reported in this paper show that there are mechanisms and approaches that ensure miscibility of oil and 'dry" inert gaseous agent in high-temperature reservoir conditions.

In previously conducted investigations, interaction of oil, kerogen, and air was studied in detail and conditions of intrastratal transformation of air into a gaseous agent were determined. The main task of the investigation was evaluation of oil displacement properties of "dry" gases in high-temperature reservoir conditions, i.e., attainment of miscibility with light oil.

Let us compare the oil displacement properties of APG and product (gas) of intrastratal air transformation (ATG). Initially, oil displacement properties of APG and ATG were investigated. In the investigations we used the slim tube method [6-9], which, unlike the common method [10], allows evaluation of the potentiality of the gaseous agent. In this work, we used recombined models of oil and gas, the composition of which is given in Tables 1 and 2.

In the experiments we used a slim tube and a Geologika-made PIK-OFP/EP filtration unit. The slim tube was a stainless-steel tube 12 m in length and 7 mm in inner diameter. For packing the slim tube, we used Ballotini 75-150 mm glass shot. The slim tube preparation for the experiment included (Table 3) cleaning with an

Table 1

Component	Content, wt. %		Component	Content, wt. %	
	Degassed oil	Recombined oil model		Recombined oil model	Degassed oil
C_1	0	5.95	C_{19}	3.95	3.74
C_2	0	0.61	C_{20}	3.88	3.56
C3	0	0.44	C_{21}	3.59	3.39
C_4	0.16	0.64	C_{22}	3.23	3.21
C_5	0.28	0.64	C_{23}	2.90	2.70
C_6	0.66	1.09	C_{24}	2.64	2.48
C_7	2.77	2.52	C_{25}	2.30	2.27
C_8	6.65	5.99	C_{26}	2.00	1.85
C_9	5.32	4.90	C27	1.82	1.72
C_{10}	4.58	4.26	C_{28}	1.65	1.59
C_{11}	4.09	3.80	C_{29}	1.55	1.35
C_{12}	3.48	3.39	C_{30}	1.45	1.46
C_{13}	4.50	4.19	C_{31}	1.32	1.20
C_{14}	4.80	4.54	C_{32}	1.16	1.09
C_{15}	4.86	4.63	C_{33}	1.13	1.09
C_{16}	4.43	3.98	C_{34}	1.12	1.05
C_{17}	5.10	4.95	C_{35}	1.01	0.99
C_{18}	4.47	4.13	C_{36+}	7.16	4.60

Table 2

Indices	APG number						ATG
	0	1	2	2a	3	4	
Content, mol. %							
nitrogen	1.06						60
carbon dioxide	0	-	-	-	-	-	10
C_1	73.59	75.2	69.0	69.0	65.2	61.6	0
C_2	9.34	8.4	9.4	9.4	11.2	11.9	0
C_3	10.66	9.1	11.6	11.6	12.7	14.2	15
i-C_4	4.08	6.3	8.6	8.6	9.2	10.6	12.5
n-C_5	-	1.0	1.4	1.4	1.8	1.6	0
C_6	1.18	0	0	0	0	0	2.5
total	99.91	100	100	100	100	100	100
Experiment number	0.1	2	4	6(22)	1	5	0.2
Average molecular mass	22.83	22.99	25.00	23.72	26.07	27.07	-

Table 3

Experiment	Injected fluid	Injection volume, p.v.	Gas breakthrough after injection, p.v.	Final pressure fall, MPa	Injection rate, ml/h	Temperature, °C	Intrapore pressure, MPa	Oil displacement factor, %
0.1	Kerosene	1.47	-	0.0695	18.0	18.6	15.95	-
	Recombined oil model of oil 1	1.55	-	0.0307	12.0	21.5	16.0	-
	APG	1.20	0.26-28	0.00715	6.0	86	16.0	29.4
		1.31	-	0.00673	6.0	86	16.0	30.4
0.2	Kerosene	1.61	-	0.090	18	22.8	16	-
	Recombined oil model of oil 1	1.64	–	0.057	13	23.2	16	-
	ATG	1.20	0.30-0.31	0.0064	6.0	85	16.0	27.2
		1.31	-	0.0066	6.0	85	16.0	27.2

alcohol-benzene mixture (1:3-4) and drying in an air current at 60-80C until constant weight. Thereafter, the slim tube was evacuated and saturated with kerosene to 18 or 22 MPa pressure by a pump. The kerosene was filtered at room temperature and put into the slim tube for filtration by the recombined oil model. The slim tube and APG were thermostatically controlled for no less than 12 h at 85-86°C and experimental pressure. During the warm-up, the inlet of the slim tube of the reservoir was closed and the outlet was open for determining the quantity of oil released over the warm-up time.

The displacing fluid (APG) injection rate was 6 cm^3/h. To determine the degree of oil and gas miscibility, we used the oil displacement factor values after injection of 1.2 p.v. of the gaseous agent: at oil displacement

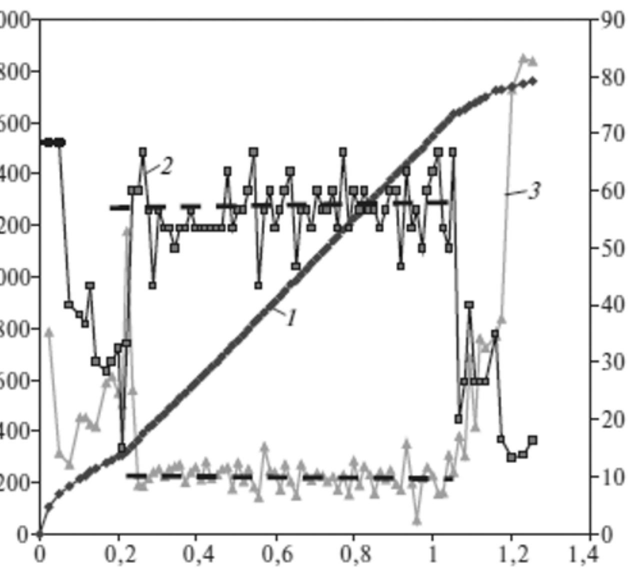

Fig. 1. Oil displacement dynamics (*1*) and variation of SF (*2*), and GF (*3*) depending on volume of injection of APG2 in Table 4.

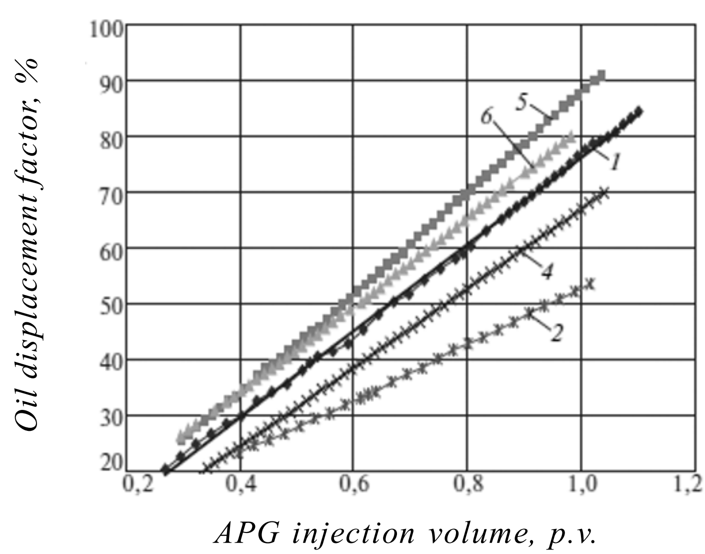

Fig. 2. Dependence of oil displacement factor on volume of APG injection for oil displacement (numerals on curves correspond to experiment numbers).

Table 4

Experiment No.	Fluid	PV	Pressure drop, MPa	Pressure, MPa	Temperature, °C	Gas factor, liter/liter	SF	Oil displacement factor, %	Injection rate, ml/h	APG breakthrough, p.v
2	Kerosene	1+0.19	-	18	23.6	-	-	-	3-45	-
	Oil	1.47	0.17		24.7	101	0.832	-	12	-
	APG 1	1.20	0.0135		59	-	-	62	6	0.12
		1.29	0.0097					64	6	1.1—1.2
4	Kerosene	1.0+0.20	0.180	18	24.6	-	-	-	18	-
	Oil	1.5	0.172		23.7	102	0.830	-	12	-
	APG 2	1.20	0.0074		59	-	-	76	6	0.2
		1.26	0.0065		59	-	-	77	6	1.07
1	Kerosene	1+0.35	-	18	23.4	-	-	-	6-24	-
	Oil	1.36	0.1623		23.6	105	0.829	-	12	-
	APG 3	1.20	0.0087		59	200	0.625	89	6	1.13
		1.27	0.0077					91	6	-
5	Kerosene	1+0.43	0.181	18	24.0	-	-	-	18	-
	Oil	1.43	0.158		22.7	113	0.863	-	12	-
	APG 4	1.20	0.0029		59	-	-	95	6	1.05
		1.285	0.0025			-	-	96	6	-
6	Kerosene	1.0+0.46	0.1907	22	23.6	-	-	-	18	-
	Oil	1.48	0.137		23.2	133	0.793	-	12	-
	APG 2a	1.20	0.0162		59	221.5	0.6	89	6	0.18-0.19
		1.26	0.0156			-	-	90	6	1.02-1.05

Table 5

2	22.99	18	13.5	62	0.12	1.1-1.2	50
4	23.72	18	13.8	76	0.2	1.07	71
6	23.72	22	18-19	89	0.18-0.19	1.05	79
1	25.00	18	<6.3	89	<0.1	1.13	77
5	27.07	18	12.2	95	0.125	1.05	89

Note.

factor of 90% and above - mixing condition of oil displacement by gas; at oil displacement factor of 60% and above - limited mixing condition of oil displacement by gas; at oil displacement factor below 60% - nonmixing condition of oil displacement by gas.

The data in Table 3 indicate that in Tyumen Formation conditions these gaseous fluids have virtually coincidental effectiveness. Virtually identical (in oil displacement level) nonmixing condition of oil displacement by gas is observed. In the case of mixing displacement of oil by gas (by APG and ATG) in conditions of West Siberian Jurassic deposit [11, 12], the situation is identical. This experiment and the experience of the investigation confirms similarity of oil-displacing properties and inter-replaceability of usual APG and the product of intrastratal air transformation into an inert gaseous agent.

In the next series of experiments, the influence of APG composition in conditions of deposit typical for Tyumen Formation (Upper Jurassic, Sigovian Formation) was studied. As an example of the dynamics of filtration experiment, we chose experiment 4 (Fig. 1, Table 4) where typical dynamics of oil displacement, changes in oil shrinkage factor (SF) upon degassing, and gas factor from the APG injection volume were observed. In this experiment (as in others), two gas breakthroughs (Fig. 2) through the porous medium of the slim tube were noticed. This fact is well marked because it is accompanied by simultaneous sharp rise of GF and fall of SF, which is typical for a gas breakthrough [15]. The first APG breakthrough (after injection of 0.21-0.22 p.v. of APG) is typical for nonmixing displacement [11] and the second breakthrough occurs after injection of more than 1 p. v. of APG (Table 4). The latter gas breakthrough indicates, first, miscibility of oil and APG (the moment of gas breakthrough was used in [11] for unambiguous determination of minimum miscibility pressure (MMP) and, second, process of dissolution of heavy APG components in the oil, which increases the oil volume, which explains oil displacement factors above 100%.

The plots in Fig. 1 show two APG breakthroughs and three stages of the oil displacement process in the experiment: initial (up to 0.21-0.22 p.v. of APG injection), developing (from 0.22 to 1 p.v. of APG injection), and final stage (the curve showing dependence of oil displacement factor on APG injection volume). In the initial stage, the oil (at the start of the reservoir model) is displaced by the original dry gas which did not have time to change its composition. This explains the nonmixing oil displacement condition [11] characterized by rise of the gas factor (GF), fall of shrinkage factor (SF), and the step in the oil displacement curve. Extrapolating the oil displacement factor-gas injection volume curve we can estimate the value of the oil displacement factor as more than 20%, which is typical for nonmixing oil displacement by gas [11].

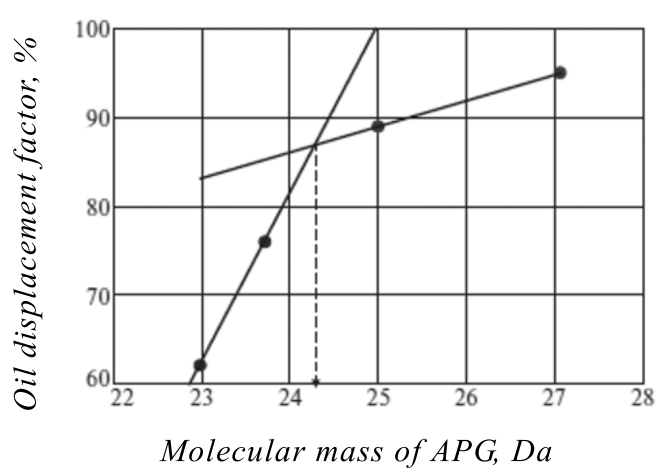

Fig. 3. Dependence of degree of oil displacement on molecular mass of APG.

The developing stage of oil displacement (after gas breakthrough 1) by gas is characterized by two-phase gas and oil filtration and lower rate of oil displacement from the slim tube (Table 4 and Fig. 2) compared to the APG injection rate (in the case of single-phase filtration, these rates should be very close). The linear pattern of the dependencies indicates stabilization of the process of simultaneous filtration of commensurable volumes of oil and APG. According Fig. 2, the share of gas in the total stream falls from 50 to 11% with rise of the molecular mass of the APG. Comparison of GF and SF shows that in the developing oil displacement stage, GF values are higher and SF values are lower than those of the original oil, which confirms simultaneous filtration of oil and gas. Fluctuations are observed in the pressure drop-APG injection volume curve (gradually diminishing toward the end of the stage), which confirm filtration of gas-liquid mixture [13].

The final filtration stage begins from gas breakthrough 2 (Fig. 1) and is characterized by rise of GF and fall of SF of the oil. Breakthrough 2 occurs after injection of about 1 p.v. of APG, which indicates mixing oil displacement condition [11].

Occurrence of two gas breakthroughs and intricate pattern of oil displacement shows that, due to mass transfer, the oil displacement condition changes gradually from nonmixing to mixing oil displacement with formation of areas of porous medium having oil displacement factor matching the displacement condition. The total oil displacement will be the sum of oil displacement factors for each area.

The study of oil displacement by APG of various compositions allowed us to draw the following conclusions:

1. APG and oil undergo change in composition in the mass transfer process, whereupon the oil gets enriched with components of the gas and increases its volume, whereas the APG becomes more "fat" although decreases in volume.

2. In the literature there is an apprehension that the mixing edge breaks up in the course of filtration. These studies showed that mass transfer may lead to miscibility even in the case of filtration of dry APG having a minor content of C_3- C_4 components, but this process requires a considerable filtration path in a reservoir having light oil. Rise in molecular weight of APG accelerates attainment of miscibility between the oil and the gaseous agent.

Let us consider the dependence of oil displacement on the average molecular mass of APG. The data in Fig. 3 and Table 5 indicate that the degree of oil displacement increases with increase of molecular mass of APG. In the oil displacement factor-average molecular mass curve, there is a break, which was taken as transition from the limitedly mixing condition of oil displacement to complete miscibility of oil and APG. The break occurs at APG molecular mass of 24.3 Da, to which corresponds 87% oil displacement, which is close to the commonly accepted oil displacement factor value (90%) typical for oil and gas miscibility. A lower oil displacement factor value is associated with the presence of asphalt-resin-paraffin deposits in the oil (a part of them falls within the reservoir model) and the area of transition from nonmixing displacement to complete mixing.

Two-phase filtration in a porous medium will increase filtration resistance during oil displacement from tight reservoirs, so it is possible to accelerate attainment of complete oil and gas miscibility. This must be achieved by prefringing of liquefied hydrocarbon gas or wide fraction of light hydrocarbons [14-17]. This is particularly important in the cases where the reservoir pressure is lower than the minimum miscibility pressure (MMP).

The work was financially supported by the Ministry of Education and Science of Russia (unique research (project) identifier RFMEFI60017X0005).

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