ISSN 2712-8008
Volume / Том 21 №1 2021
Journal Homepage: http://vestnik.pstu.ru/geo/

Perm Journal of Petroleum and Mining Engineering

UDC 622.06
Article / Статья

Estimation of the Influence of Associated Petroleum Gas with a High Carbon Dioxide Content on the Oil Displacement Regime in the Development of the Tolumskoye Field

Oleg A. Morozyuk[1], Stanislav A. Kalinin[1], Sergey A. Kalinin[1], Andrey S. Scvortsov[1], Sergey V. Melekhin[1], Andrey V. Stenkin[2], Ruslan R. Mardamshin[2], Gennady A. Usachev[3], Dmitry A. Mett[3]

[1]PermNIPIneft branch of LUKOIL-Engineering LLC in Perm (3a Permskaya st., Perm, 614015, Russian Federation)
[2]LUKOIL-Western Siberia LLC, TPE Urayneftegaz (116a Lenina st., Urai, 628285, Russian Federation)
[3]Head office of LUKOIL-Engineering LLC (Bldg. 1, 3 Pokrovsky Boulevard, Moscow, 109028, Russian Federation)

Оценка влияния попутного нефтяного газа с высоким содержанием диоксида углерода на режим вытеснения нефти при разработке Толумского месторождения

О.А. Морозюк[1], С.А. Калинин[1], С.А. Калинин[1], А.С. Скворцов[1], С.В. Мелехин[1], А.В. Стенькин[2], Р.Р. Мардамшин[2], Г.А. Усачев[3], Д.А. Метт[3]

[1]Филиал ООО «ЛУКОЙЛ-Инжиниринг» «ПермНИПИнефть» в г. Перми (Россия, 614015, г. Пермь, ул. Пермская, 3а)
[2]ООО «ЛУКОЙЛ-Западная Сибирь», ТПП «Урайнефтегаз» (Россия, 628285, Ханты-Мансийский автономный округ, г. Урай, ул. Ленина, 116а)
[3]Головной офис ООО «ЛУКОЙЛ-Инжиниринг» (Россия, 109028, г. Москва, Покровский бульвар, 3, стр. 1)

Received / Получена: 25.07.2020. Accepted / Принята: 02.11.2020. Published / Опубликована: 11.01.2021

Keywords:
experimental studies, minimum miscibility pressure, associated petroleum gas, gas, oil, slim-tube, displacement mode, miscible oil displacement.

Depending on reservoir conditions, composition of reservoir oil and gas agent, various modes of oil displacement by gas can be implemented in reservoir conditions. The most preferable mode from the standpoint of the completeness of oil recovery is the mode of miscible displacement of oil by gas. The main parameter indicating the achievement of the miscible displacement mode is the minimum miscibility pressure. The most popular and reliable laboratory method for determining the minimum mixing pressure is the slim-tube method.
The results are presented related to laboratory studies performed to determine the value of the minimum miscibility pressure of reservoir oil from the Tolumskoye field and associated petroleum gas of the Semividovskaya group of fields and also to determine the mode of oil displacement by associated petroleum gas. To determine the parameters of reservoir oil and change its properties at various molar concentrations, the standard PVT research technique was used. To determine the minimum miscibility pressure, the slim-tube technique was used. To assess the mechanism of miscibility process development, chromatographic analysis of the sampled gas composition and visual analysis of the phase fluids behavior by means of a visual cell were additionally performed.
Two series of filtration experiments were performed on slim models aimed at displacement of the recombined oil model of the Tolumskoye field by the model of associated petroleum gas from the Semividovskaya group of fields. According to the obtained dependence of the oil displacement coefficient on pressure, when oil from the Tolumskoye field was displaced by associated petroleum gas of the Semividovskaya group of fields, the minimum miscibility pressure would be 14.8 MPa.
Based on the criteria for determining the mixing mode, as a result of generalization and comprehensive analysis of the research results, it was found that for the conditions of the Tolumskoye field, the mode of oil displacement by associated petroleum gas of the Semividovskaya group of fields was the mode of the developed multi-contact miscible displacement (the mechanism of condensation of solvent components into the oil phase).

Ключевые слова:
экспериментальные исследования, минимальное давление смесимости, попутный нефтяной газ, газ, нефть, slim-tube, режим вытеснения, смешивающееся вытеснение нефти.

В зависимости от пластовых условий, состава пластовой нефти и газового агента, в пластовых условиях могут реализовываться различные режимы вытеснения нефти газом. Наиболее предпочтительным режимом с позиции полноты извлечения нефти, является режим смешивающегося вытеснения нефти газом. Основным параметром, указывающим на достижение режима смешивающегося вытеснения нефти, является минимальное давление смесимости(МДС). Наиболее востребованным и достоверным лабораторным методом определения МДС является метод slim-tube.
Представлены результаты лабораторных исследований, выполненные с целью определения величины МДС пластовой нефти Толумского месторождения и попутного нефтяного газа (ПНГ) Семивидовской группы месторождений и определения режима вытеснения нефти ПНГ. Для определения параметров пластовой нефти и изменения ее свойств при различной мольной концентрации ПНГ использовалась стандартная методика PVT-исследований. Для определения МДС использовалась методика slim-tube. Для оценки механизма развития процесса смешиваемости дополнительно производился хроматографический анализ состава отбираемого газа и визуальный анализ фазового поведения флюидов посредством визуальной ячейки.
Выполнены две серии фильтрационных опытов по вытеснению рекомбинированной модели нефти Толумского месторождения моделью ПНГ Семивидовской группы месторождений на слим-моделях. Согласно полученной зависимости коэффициента вытеснения нефти от давления, при вытеснении нефти Толумского месторождения попутным нефтяным газом Семивидовской группы месторождений величина МДС составит 14,8 МПа.
Опираясь на критерии определения режима смешения, в результате обобщения и комплексного анализа результатов исследований установлено, что для условий Толумского месторождения, режимом вытеснения нефти попутным нефтяным газом Семивидовской группы месторождений является режим развиваемого многоконтактного смешивающегося вытеснения (механизм конденсации компонентов растворителя в нефтяную фазу).

Oleg A. Morozyuk (Author ID in Scopus: 56006963800) – PhD in Engineering, Head of the Department of Research of Thermal Reservoir Stimulation Methods (tel.: +007 342 717 01 66, e-mail: Oleg.Morozyuk@pnn.lukoil.com). The contact person for correspondence.
Stanislav A. Kalinin (Author ID in Scopus: 57194691912) – Leading Engineer of the Department of Analytical Processing of Core Research Results (tel.: +007 342 717 01 66, e-mail: Stanislav.Kalinin@pnn.lukoil.com).
Sergey A. Kalinin – Engineer of the Department of Research of Thermal Reservoir Stimulation Methods (tel.: +007 342 717 01 66, e-mail: Sergej.Kalinin@pnn.lukoil.com).
Andrey S. Scvortsov (Author ID in Scopus: 57194692889) – Engineer of the Department of Research of Thermal Reservoir Stimulation Methods (tel.: +007 342 717 01 66, e-mail: Andrej.Skvortsov@pnn.lukoil.com).
Sergey V. Melekhin (Author ID in Scopus: 56979229100) – Head of the Department of Research of Enhanced Oil Recovery Methods on Cores (tel.: +007 342 717 01 66, e-mail: Sergej.Melehin@pnn.lukoil.com).
Andrey V. Stenkin (Author ID in Scopus: 57206473477) – Deputy General Director for Field Development – Chief Geologist (e-mail: Andrey.Stenkin@lukoil.com).
Ruslan R. Mardamshin (Author ID in Scopus: 57215119658) – Head of the Department of Enhanced Oil Recovery Technologies (e-mail: Ruslan.Mardamshin@lukoil.com).
Gennady A. Usachev (Author ID in Scopus: 57211299608) – Head of the Department of Development of High-Viscosity and Unconventional Oil Reserves (e-mail: Gennadiy.Usachev@lukoil.com).
Dmitry A. Mett (Author ID in Scopus: 36091660600) – Head of the Department of Geological Study of Unconventional Objects (e-mail: Dmitrij.Mett@lukoil.com).

Морозюк Олег Александрович – начальник отдела исследований тепловых методов воздействия на пласт, канд. техн. наук (тел.: +007 342 717 01 66, e-mail: oleg.morozyuk@pnn.lukoil.com). Контактное лицо для переписки.
Калинин Станислав Александрович – главный специалист отдела аналитической обработки результатов исследований керна (тел.: +007 342 717 01 66, e-mail: stanislav.kalinin@pnn.lukoil.com).
Калинин Сергей Александрович – инженер отдела исследований тепловых методов воздействия на пласт (тел.: +007 342 717 01 66, e-mail: Sergej.Kalinin@pnn.lukoil.com).
Скворцов Андрей Сергеевич – инженер отдела исследований тепловых методов воздействия на пласт (тел.: +007 342 717 01 66, e-mail: Andrej.Skvortsov@pnn.lukoil.com).
Мелехин Сергей Викторович – начальник управления исследований методов повышения нефтеотдачи пласта на керне (тел.: +007 342 717 01 66, e-mail: Sergej.Melehin@pnn.lukoil.com).
Стенькин Андрей Вениаминович – заместитель генерального директора по разработке месторождений-главный геолог (e-mail: Andrey.Stenkin@lukoil.com).
Мардамшин Руслан Рамзисович – начальник отдела технологий повышения нефтеотдачи (e-mail: Ruslan.Mardamshin@lukoil.com).
Усачев Геннадий Александрович – начальник управления разработки высоковязких и трудноизвлекаемых запасов нефти (e-mail: Gennadiy.Usachev@lukoil.com).
Метт Дмитрий Александрович – начальник отдела геологического изучения трудноизвлекаемых объектов (e-mail: Dmitrij.Mett@lukoil.com).

Please cite this article in English as:
Morozyuk O.A., Kalinin S.A., Kalinin S.A., Scvortsov A.S., Melekhin S.V., Stenkin A.V., Mardamshin R.R., Usachev G.A., Mett D.A. Estimation of the Influence of Associated Petroleum Gas with a High Carbon Dioxide Content on the Oil Displacement Regime in the Development of the Tolumskoye Field. *Perm Journal of Petroleum and Mining Engineering*, 2021, vol.21, no.1, pp.42-48. DOI: 10.15593/2712-8008/2021.1.7

Просьба ссылаться на эту статью в русскоязычных источниках следующим образом:
Оценка влияния попутного нефтяного газа с высоким содержанием диоксида углерода на режим вытеснения нефти при разработке Толумского месторождения / О.А. Морозюк, С.А. Калинин, С.А. Калинин, А.С. Скворцов, С.В. Мелехин, А.В. Стенькин, Р.Р. Мардамшин, Г.А. Усачев, Д.А. Метт // Недропользование. – 2021. – Т.21, №1. – С.42–48. DOI: 10.15593/2712-8008/2021.1.7

Introduction

The process of gas stimulation of the oil reservoir involves the injection of a gas agent into the formation in order to achieve miscibility [1]. The classic technology is performed by injecting a large volume of gas into the formation for oil displacement. However, an adverse ratio of viscosities of the displaced oil and injected gas causes formation of gas fingers that break through into the production wells and lead to a dramatic increase in the gas-oil ratio and a decrease in oil production rates. In order to eliminate the issue of fingering, gas injection technology is combined with water injection in various forms. This technology can be implemented in the following forms: carbonated water injection [2–4], gas-oil displacement with subsequent water-oil displacement [5], alternate injection of water and gas rims (WAG) [6, 7].

Recently, many oil-well experts have been researching a technology that is more likely a type of a group of water-gas stimulation technologies [8] which consists of injecting a highly dispersed water and gas mixture (water-gas mixture (WGM)) at a specific volumetric phase ratio. This high-potential technology can substantially increase the efficiency of oil displacement; its implementation, however, is facing a number of technical and technological challenges [8–10].

One of the types of technologies that use gases is the gas cycling technology (Huff'n'Puff) [11] which is implemented through the injection of a gas agent into the formation in cycles. Each cycle has three successive steps: 1) gas injection, 2) soaking, 3) well sampling.

Gases such as nitrogen [12, 13], carbon dioxide [14, 15], flue gases [16, 17], hydrocarbon "dry" gases (methane) and "upgraded" gases (e.g. associated petroleum gas) can be used as gas agents [18].

Depending on the reservoir conditions, reservoir oil composition and gas agent, various scenarios of oil displacement by gas can be implemented in reservoir conditions [19, 20]. There are three main gas-oil displacement scenarios [21]: 1) immiscible displacement, 2) partially-miscible displacement (or displacement with developed miscibility or multiple-contact miscibility), 3) fully miscible displacement (or miscible displacement at the first contact). The most preferable scenario in terms of the completeness of oil recovery is the completely miscible displacement of oil by gas which is implemented at pressures above the so-called minimum miscibility pressure (MMP).

It is important to determine the displacement scenario and MMP when estimating the efficiency of oil displacement by gas agents (as well as other technologies that use gas as a displacement agent). Due to the fact that the results of these studies depend on the temperature and pressure conditions of the given formation, oil composition and the applied gas agent, an important step of laboratory studies is to prepare fluid samples. This step also includes the preparation of a recombined oil sample with a gas agent model followed by conducting a set of PVT studies according to the data [22].

The mechanism of oil displacement by means of a gas agent and the MMP can be determined by both calculation (using state equations) [23–25] and a number of experimental methods [26–29]. However, the most consistent results can be provided by experimental methods only.

This paper presents the results of laboratory studies performed to determine the value of the minimum miscibility pressure (MMP) of reservoir oil from the Tolumskoye field and associated petroleum gas (APG) of the Semividovskaya group of fields and also to determine the scenario of oil displacement by associated petroleum gas. The standard PVT research technique was used to determine the parameters of reservoir oil and changes in its properties at various molar concentrations of APG. The slim-tube technique was used to determine the MMP. In order to assess the mechanism of the miscibility process development, chromatographic analysis of the sampled gas composition and visual analysis of the phase fluids behavior by means of a visual cell were additionally performed.

Research Procedure

The most popular and reliable laboratory method for determining the minimum miscibility pressure is the slim-tube method [30].

The slim-tube method facilitates the task of determining the gas-oil displacement scenario in given pressure-temperature conditions and settings that allow for the miscible oil displacement using a gas agent. This method is also good for comparing different displacement agents and finding the right gas composition for a given field.

The slim-tube method of the MMP measurement consists of a set of experiments carried out to displace oil with a solvent agent using long tubes of small diameter. The tube diameter is usually 4–15 mm [31–33]. The tube length varies from 6 to 40 m. The tube is usually filled with porous media with small particle sizes to meet the condition $D_{tube}./D_{particles} > 10$ [34].

There is no clear and precise procedure for measuring MMP by the slim-tube method at the moment, therefore there are many various criteria for analyzing the miscibility of reservoir oil and gas designed before the 1990s:

– oil displacement factor of 90 % and above at 1–1.2 V_{pore} injected into the slim model [35–37];

– oil displacement factor of 95 % and above after the gas breakthrough for some types of injection agents [38] and 80 % after the gas breakthrough and the final oil displacement factor of 94 % for most of the displacement agents [39, 40];

– oil displacement factor of 94 % and above when gas factor reaches the set value [39, 40];

– The MMP is determined in a set of experiments at different displacement pressures at 1.2 V_{pore} injected into the slim model. The MMP corresponds to the breakpoint of the displacement factor – displacement pressure curve [30, 41, 42], as well as a number of others [42–44].

It is often assumed that full miscibility is achieved when at least 90 % of oil is displaced after injection of a gas agent in a volume equal to 1.2 pore volumes of the slim model. If the experiment results show that the final displacement factor is less than 50–60 %, the displacement process is considered to be immiscible. Obtaining an intermediate value of the displacement factor (60–90 %) corresponds to the conditions of partial miscibility. At least five experiments with different displacement pressures are carried out, after which a graph of the dependence of the oil displacement factor on the displacement pressure is constructed. The intersection point of the line dropped vertically from the breakpoint of the experiment curve onto the pressure axis corresponds to the MMP value (Fig. 1).

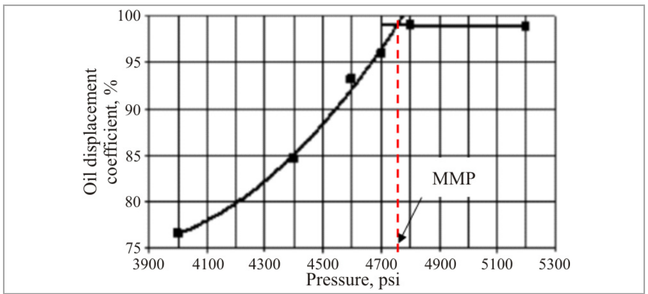

Fig. 1. Displacement factor vs pressure curve (example)

Fig. 2. Three-phase filtration apparatus and slim model in the oven

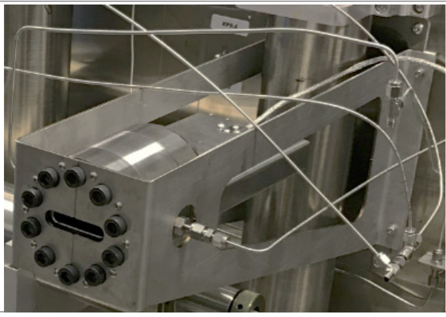

Fig. 3. Cell with a sight glass for checking up on phase behavior of fluids

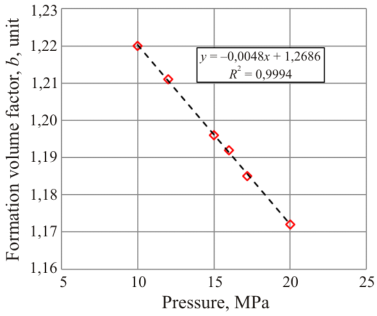

Fig. 4. Volume factor of the recombined oil model of the Tolumskoye field vs. pressure

Table 1

Specifications of the appliance for determining minimum miscibility pressure

Parameter	Value
Tube length, m	12
Tube outside diameter, mm	6
Material	Stainless steel
Packing material	Glass microspheres
Grain size, mesh	100
Porosity, %	38.4
Gas permeability, μm^2	33
Pore volume, cm^3	130.4
Maximum operating pressure, MPa	40.0
Maximum operating temperature, °C	200

The processing of the results of filtration experiments using slim models and the evaluation of the miscibility mechanism were carried out according to the criteria given in [45]. The authors suggested to use the following experimental data:

– dynamics of methane concentration in gas escaping from displaced oil,

– phase behavior of fluids as they leave the slim model,

– dynamics of the pressure difference between the ends of the slim model,

– displacement factor value.

Equipment Description

The researchers used modern laboratory equipment that provided the possibility to perform filtration experiments using core and bulk formation models with the application of different displacement agents in a wide range of temperatures and pressures (Fig. 2). The appliance consisted of several units for various functions. See [46] for the detailed description.

The associated petroleum gas model (APG) was injected by using the gas preparation unit designed to compress and heat gas up to the required pressure and temperature and supply the prepared gas to the injection pump. The phase measurement at the slim model outlet was performed by using an apparatus for measuring the volume of fluids that consists of a three-phase visual separator and special piston-type flow meters positioned after the separator. The phase behavior of the fluids sampled during the experiment was checked by using a high-pressure cell with a sight glass installed in front of the back pressure valve (Fig. 3). Table 1 shows technical specifications for the used slim model.

Preparing Formation Fluid Models

A recombined reservoir oil sample of the Tolumskoye field and an APG model of the Semividovskaya group of fields were prepared for the filtration experiments using slim-models.

The recombined oil sample was prepared in a special recombination chamber. The sample is mixed in the mixing cell at the pressure of up to 25 MPa and at the temperature of up to 150 °C. The fluid is mixed by a ball moving inside the cell.

The recombined sample was prepared using a wellhead oil sample from the production wells of the Tolumskoye field. The following physicochemical properties of the wellhead sample were determined before the experiment: irreducible water saturation, viscosity and density at 20 °C, weight content of asphaltens, resins and paraffins, molecular weight and components.

The recombined oil model was prepared in the following order:

a) dehumidification of the original degassed oil sample;

b) adding an estimated amount of degassed oil and reservoir gas into the recombination cell in a volume corresponding to the gas/oil ratio in the reservoir conditions. Defining the ratio of the gas model components based on the composition of the reservoir gas from the Eastern reservoir of the Tolumskoye field;

c) increasing the pressure and temperature in the recombination vessel up to the initial in situ conditions of the Eastern reservoir of the Tolumskoye field;

d) mixing oil and gas until reaching a single-phase state;

e) measuring the current gas/oil ratio by the flash separation method while mixing the recombined sample;

The PVT properties of the recombined oil sample were defined according to OST 153-39.2-048-2003 Oil. Model study of reservoir fluids and separated oils.

At the stage of the PVT studies of the recombined oil model, correlations between the volume factor and pressure were determined (Fig. 4). These correlations were used later for calculations of oil displacement factors.

The APG model was prepared using the statistical partial pressure method. The compositional analysis of the gas mixture was carried out by using a gas sample taken from the vessel for gas chromatographic analysis. Table 2 shows the comparison between the composition of the APG model used for the experiments and that of the real APG of the Semividovskaya group of fields.

Table 2

Composition of APG of the Semividovskaya group of fields and of its model

Component	Designation	APG of the Semividovskaya group of fields, mol. %	APG model, mol. %
Carbon dioxide	CO_2	68–72	69.0
Nitrogen	N_2	0.5–1.5	1.2
Methane	CH4	18–20	19.3
Ethane	C2H6	0.5–1.5	1.2
Propane	C3H8	4–7	6.5
Butane (group)	C4H10	0.1–0.5	0.4

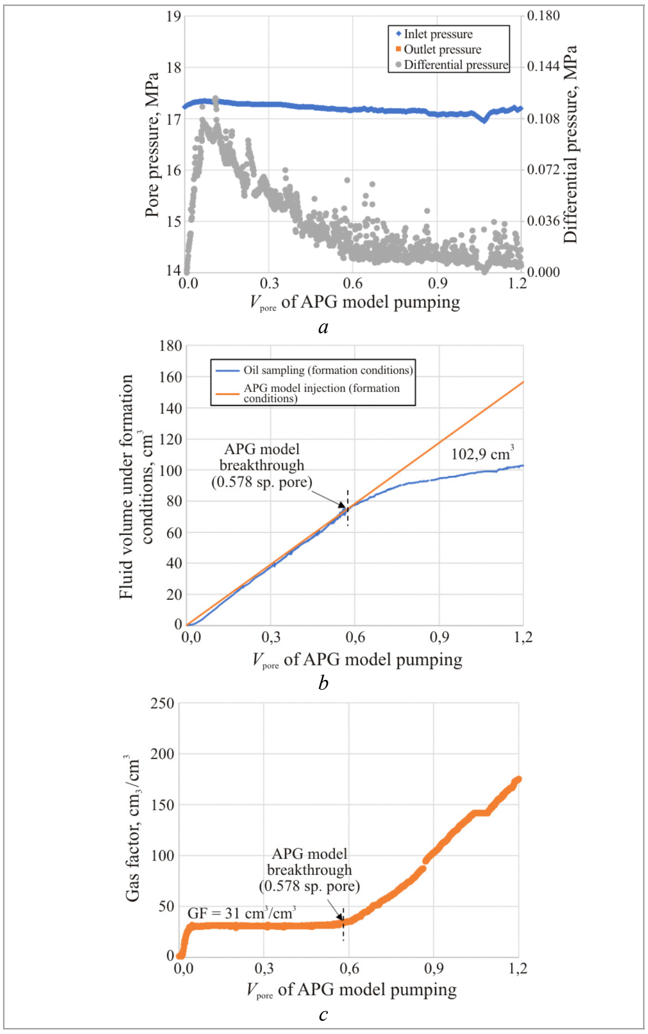

Fig. 5. Standard experiment results: *a* – dynamics of pore and differential pressures during the experiment on determination of the oil displacement factor using slim tubes; *b* – dynamics of oil displacement depending on the volume of the injected APG in slim tube pore volumes; *c* – dynamics of the gas factor depending on the volume of the injected APG in slim tube pore volumes

Experiment Procedures

The slim model preparation included the following steps:

a) he slim model was put under vacuum for 2 hours;

b) saturating the slim model with minimum 3 V_{pore} of kerosene by means of kerosene filtration;

c) injecting the recombined oil sample through the slim model at the formation temperature of 91 °C and at a pressure higher than the saturation pressure.

The oil displacement stage was performed as described below:

a) setting the required pore pressure stage in the slim tube;

b) holding the slim model at the formation temperature and set pore pressure for 24 hours;

c) injecting APG into the slim model with a constant volume flow rate of 0.08 cm³/min providing a low pressure gradient along the length of the slim model;

d) measuring volumes of fluids as they leave the slim model by means of piston-type flow meters as often as it may be necessary to determine the composition (oil up to C30+, gas up to C6+) and physicochemical properties;

e) analyzing changes in composition of gas escaping from oil by taking gas samples after every 0.1 pore volumes of APG injected and analyzing it with a gas chromatograph;

f) analyzing changes in composition of oil based on the components, density, viscosity and content of asphaltenes, resins and paraffins of degassed oil samples taken during the experiment;

g) checking up on the phase behavior (in reservoir conditions) of fluids leaving the slim model by means of a special visual cell;

h) injecting APG in a volume equal to 1.2-times the volume of the slim model void space, after which the experiment was stopped;

i) the oil displacement factor ($K_{disp.}$) was calculated based on the total volume of oil samples taken for analysis by the following equation:

$$K_{вт} = \frac{V_{вн} \cdot b - V_{мерт}}{V_{пор}},$$

where $V_{disp.\ oil}$ is the displaced oil volume, cm³; b is the oil volume factor corresponding to the pore pressure stage and formation temperature, units; V_{void} is the void volume of the hydraulic system, cm³; V_{pore} is the pore volume of the slim model which equals to the volume of oil originally present in the slim model, cm³.

The slim model was cleaned as described below:

a) heating the oven with the slim model up to the temperature of 150 °C;

b) injecting white spirit through the tube until it comes out of the tube completely discolored;

c) cooling the oven with the slim model down to room temperature;

d) injecting 2 times the pore volume of kerosene through the slim model at a pressure equal to the next stage pore pressure;

e) re-saturating the slim model with the recombined oil sample.

Results of Filtration Experiments using Slim Tubes

Within the research, two sets of experiments were performed to displace the oil model of the Tolumskoye field by the APG model from the Semividovskaya group of fields. The second set of experiments was carried out in order to repeat the first set and thus improve the reliability of the research results. Figure 6 shows typical outcomes of the experiments. Table 3 summarizes the outcomes of the experiments.

Figure 5 shows correlations between oil displacement factor and pore pressure value obtained using slim tubes.

As one can see from the data shown in Figure 6, an increase in the displacement pressure entails growth of the displacement factor. At pressure stages from 15 to 17.2 MPa, the oil displacement factor is nearly stabilized. An experiment performed at 20 MPa showed that the displacement factor keeps increasing along with the increase in the displacement pressure.

Table 3

Results of the experiment on the MMP measurement

Experiment No.	$T_{formation}$, °C	Stage $P_{formation}$, MPa	APG volume flow rate (CO_2), cm^3/min	Differential pressure in the tube, MPa: max	Differential pressure in the tube, MPa: after gas breakthrough	Oil displacement factor after injection of 1.2 V_{pore} of APG, %
Set 1						
1	91	10	0.080	0.144	0.017	0.379
2	91	12	0.080	0.134	0.018	0.530
3	91	15	0.080	0.121	0.016	0.715
4	91	16	0.080	0.117	0.011	0.699
5	91	17.2	0.080	0.111	0.012	0.707
Set 2						
1	91	12	0.080	0.132	0.015	0.536
2	91	15	0.080	0.132	0.014	0.666
3	91	16	0.080	0.116	0.012	0.675
4	91	17.2	0.080	0.109	0.013	0.666
5	91	20	0.080	0.114	0.013	0.758

Table 4

Evaluation of the displacement mechanism

Criterion	Displacement mechanism: First contact miscible displacement	Multiple-contact miscibility: Condensation	Multiple-contact miscibility: Evaporation	Immiscible displacement
Rapid change in methane concentration	No	Yes	No	Significant arch of methane concentration
Two phases in the visual cell	No	Yes	No	Yes/large number of bubbles in the flow
Low pressure difference after injection of 1.2 V_{pore} of solvent	Yes	Yes	Yes	No
Displacement factor value after injection of 1.2 V_{pore} of solvent, %	≥90	≥90*	≥90	<90

Note: * – low displacement factor values are caused by insufficient development of the transition section in the slim tube. The criteria that correspond to the results obtained during researches are shown in green.

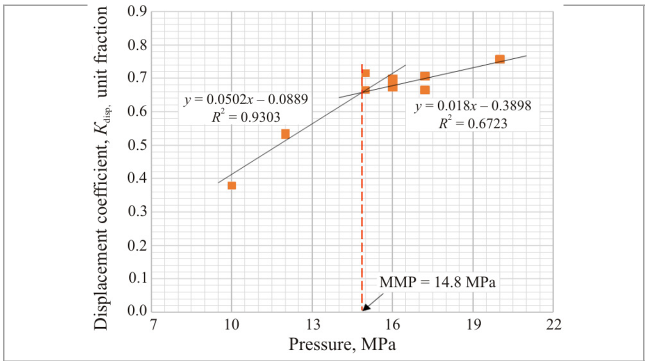

Fig. 6. Correlation between oil displacement factor and pore pressure value based on the results of filtration experiments

The points before the break obtained at 10, 12 and 15 MPa, as well as the points after the break at 16, 17.2 and 20 MPa were approximated by linear dependencies. The normal dropped vertically from the intersection point of the straight lines onto the pressure axis corresponds to the MMP value which amounts to 14.8 MPa.

The obtained displacement factor values show the absence of miscible displacement at the first contact (the oil displacement factor is significantly less than 100 %). Yet they cannot indicate an immiscible displacement process since such displacement factor values may be caused by the sizes of the transition section that might be not fully developed in the simulation conditions, which did not allow for a more complete displacement of oil from the slim tube. Therefore, the displacement mechanism was evaluated based on the set of criteria described earlier.

Analysis of the fluids composition. According to the procedure described above, the dynamics of methane concentration in the sampled gas was separately analyzed for the further analysis of the results in order to determine the displacement scenario. Changes in composition of gas escaping from oil were analyzed during filtration experiments by taking gas samples after every 0.1 pore volumes of the injected APG model with their immediate loading into the gas chromatograph. Figure 7 shows the results of the chromatographic analysis of gas samples taken at 16 and 17.2 MPa.

At the first stage of the experiment, methane concentration corresponds to that in gas dissolved in oil, since only oil is displaced. Then, before APG breaks through, a rapid change in methane concentration occurs which is characterized by the "peak" value and "arch" dimensions. After the peak, a rapid decrease in methane concentration occurs, which is the consequence of the APG model breakthrough. Ultimately, the methane concentration reaches the level that corresponds to the APG model composition. The research [15] states that such a peak indicates the development of the multiple-contact miscible displacement process. The authors also note that a rapid change in methane concentration and formation of an arch reliably indicate that the oil composition is not changing.

The results of the chromatographic analysis of samples confirm the fact that the properties of oil of the Tolumskoye field do not change during the APG displacement. Figure 7 shows the results of the chromatographic analysis of oil samples taken at 16 MPa during the experiment (oil composition is shown without heavy residue C35+).

Observation of the phase behavior. The phase behavior is one of the criteria in evaluating the oil displacement mechanism. The video records of the phase behavior of fluids displaced from the slim tube were also used to interpret the results. The following phase behavior types can be observed when fluids move in the course of the experiments:

a) one phase is present – first contact miscible displacement or developed multiple-contact miscible displacement with the evaporation of components into a gas phase;

b) the presence of small gas bubbles that start moving along with oil right before the displacement agent breaks through indicates the developed multiple-contact miscible displacement scenario with the condensation of gas into an oil phase. In this case, methane concentration is characterized by a concentration arch that is present before the gas agent breaks through;

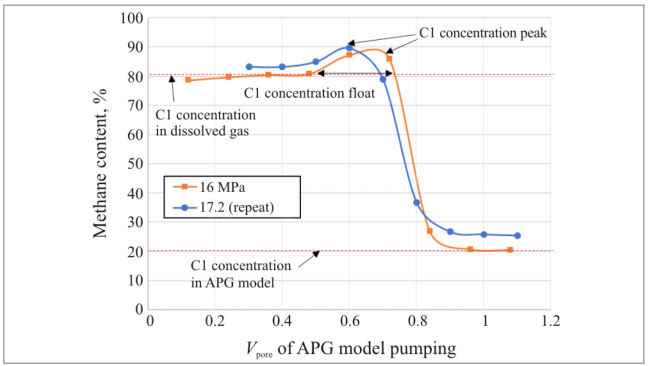

Fig. 7. Dynamics of methane concentration in the sampled gas during experiments at pressures of 16 MPa (set 1) and 17.2 MPa (set 2)

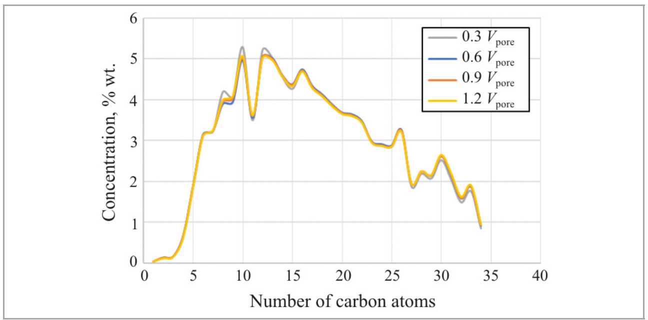

Fig. 8. Compositional analysis of degassed oil samples taken during the experiment performed at 16 MPa using a slim tube

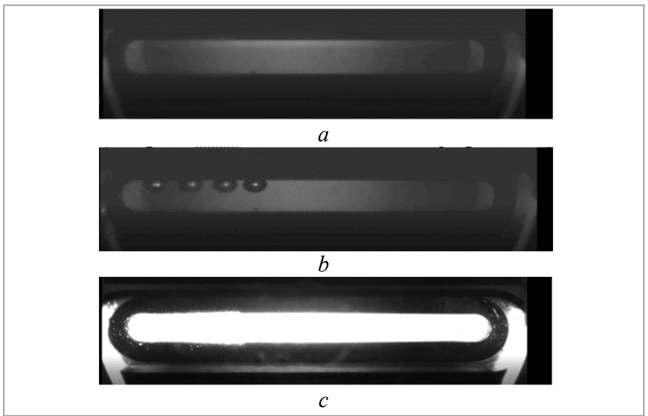

Fig. 9. Results of the visual observation of the phase behavior of fluids as they leave the slim model: *a* – the first experiment stage (set 1, experiment No. 3, 15 MPa, injection: 0 V_{pore}); *b* – the APG model starts breaking through (set 1, experiment No. 3, 15 MPa, injection: 0.655 V_{pore}); *c* – the last experiment stage (set 1, experiment No. 3, 15 MPa, injection: 1–1.2 V_{pore})

c) a large number of bubbles emerging during the displacement process indicate that the displacement is immiscible.

Figure 9 shows typical displacement stages seen in the visual cell by using an experiment performed at 15 MPa as an example.

Gas bubbles start moving before APG breaks through. After the breakthrough, one can see a clear separation of two phases in the visual cell. After that, oil moves in the lower part of the sight glass, while gas moves in its upper part.

Table 4 presents a detailed summary of the experimental results.

Conclusions

The following conclusions can be drawn based on the research results.

According to the obtained dependence of the oil displacement coefficient on pressure, when oil from the Tolumskoye field is displaced by associated petroleum gas of the Semividovskaya group of fields, the minimum miscibility pressure would be 14.8 MPa.

The profiles of methane concentration in gas released from the oil displaced during the experiments are characterized by a rapid change in methane concentration. This rapid change in concentration shows that a multiple-contact miscible displacement process is being developed in the formation, and that oil composition does not change when displacement of oil by APG is ongoing.

The analysis of physicochemical properties and chromatographic analysis of degassed oil samples confirm that oil composition remains the same during displacement of oil by APG.

The pressure difference observed during the experiment significantly decreases by the time the APG model is injected in a volume equal to 1.2 V_{pore} of the slim tube, which indicates the formation of the multiple-contact or first contact miscible displacement process.

Visual observation established that right before the APG model breaks through the slim tube, gas bubbles start moving. After the breakthrough, the formation of two phases occurs as observed in the visual cell. This situation is typical for all the performed experiments.

The oil displacement factor values obtained at pressures higher than MMP are below 90 %. Low displacement factor values are caused by insufficient development of the transition section for which there might not be enough time to develop on a slim 12 m long tube in the given simulation conditions (composition of the recombined oil sample and APG model, temperature and pressure conditions), which is confirmed by the same displacement factors obtained during repeated experiments.

Based on the criteria for determining the mixing mode, as a result of generalization and comprehensive analysis of the research results, it was found that for the conditions of the Tolumskoye field, the type of oil displacement by associated petroleum gas of the Semividovskaya group of fields was the developed multiple-contact miscible displacement (the mechanism of condensation of solvent components into oil phase).

References

1. Zheltov Iu.P. Razrabotka neftianykh mestorozhdenii [Oil fields development]. Moscow: Ripol Klassik, 1986.
2. Tumasian A.B. et al. Promyslovyi opyt vytesneniia nefti karbonizirovannoi vodoi [Field experience of oil displacement with carbonated water]. *Geologiia i razrabotka neftianykh mestorozhdenii vostoka Volgo-Ural'skoi provintsii*, 1975, 140 p.
3. Kovalenko K.I. Uvelichenie nefteotdachi plastov putem zakachki karbonizirovannoi vody [Increased oil recovery by injection of carbonated water]. *Neftianoe khoziaistvo*, 1964, no. 11, 12 p.
4. Babalian G.A. Primenenie karbonizirovannoi vody dlia uvelicheniia nefteotdachi [The use of carbonated water for enhanced oil recovery]. Moscow: Nedra, 1976, 144 p.
5. Surguchev M.G. Vtorichnye i tretichnye metody uvelicheniia nefteotdachi plastov [Secondary and tertiary methods of enhanced oil recovery]. Moscow: Nedra, 1985, 308 p.
6. Christensen J.R., Stenby E.H., Skauge A. Review of WAG Field Experience. *SPE Res Eval & Eng*, 1998, no. 4(2), pp. 97-106. SPE-71203-PA. DOI: 10.2118/71203-PA
7. Afzali S., Rezaei N., Zendehboudi S. A comprehensive review on enhanced oil recovery by water alternating gas (WAG) injection. *Fuel*, 2018, vol. 227, p. 218-246. DOI: 10.1016/j.petrol.2017.07.066
8. Zatsepin V.V. Tekhnologicheskie osnovy vodogazovogo vozdeistviia na plasty s trudnoizvlekaemymi zapasami nefti v nizkopronitsaemykh kollektorakh [Technological bases of water-gas stimulation of reservoirs with hard-to-recover oil reserves in low-permeability reservoirs]. Ph. D. thesis. Kazan', 2017.
9. Zatsepin V.V., Maksutov R.A. Sovremennoe sostoianie promyshlennogo primeneniia tekhnologii vodogazovogo vozdeistviia [Review of wag process industrial application. Modern consist]. *Neftepromyslovoe delo*, 2009, no. 7, pp. 31-21.
10. Drozdov A.N., Drozdov N.A. Uvelichenie KIN: vodogazovoe vozdeistvie na plast Opyt ekspluatatsii nasosno-ezhektornoi sistemy i puti sovershenstvovaniia tekhnologii VGV [Increase in oil recovery factor: water-gas impact on the reservoir Experience in the operation of the pump-ejector system and ways to improve the WAG technology]. *Neftegaz. RU*, 2017, no. 7, pp. 70-77.
11. Mohammed-Singh L.J. et al. Screening criteria for CO2 huff'n'puff operations. *SPE/DOE Symposium on Improved Oil Recovery, 22-26 April, Tulsa, Oklahoma, USA*, 2006. DOI: 10.2118/100044-MS
12. Alagorni A.H., Yaacob Z.B., Nour A.H. An overview of oil production stages: enhanced oil recovery techniques and nitrogen injection. *International Journal of Environmental Science and Development*, 2015, vol. 6, no. 9, pp. 693-701. DOI: 10.7763/IJESD.2015.V6.682
13. Denney D. et al. Enhanced oil recovery with high-pressure nitrogen injection. *Journal of petroleum technology*, 2001, vol. 53, no. 01, pp. 55-56. DOI: 10.2118/62547-MS
14. Blunt M., Fayers F.J., Orr Jr F.M. Carbon dioxide in enhanced oil recovery. *Energy Conversion and Management*, 1993, vol. 34, no. 9-11, pp. 1197-1204. DOI: 10.1016/0196-8904(93)90069-M

15. Glazova V.M., Ryzhik V.M. Primenenie dvuokisi ugleroda dlia povysheniia nefteotdachi plastov za rubezhom [The use of carbon dioxide for enhanced oil recovery abroad]. Moscow: VNIIOENG, 1986, 45 p.
16. Shokoya O.S. et al. The mechanism of flue gas injection for enhanced light oil recovery. *Journal of Energy Resources Technology*, 2004, vol. 126, no. 2, pp. 119-124. DOI: 10.1115/1.1725170
17. Bender S., Akin S. Flue gas injection for EOR and sequestration: Case study. *Journal of Petroleum Science and Engineering*, 2017, vol. 157, pp. 1033-1045. DOI: 10.1016/j.petrol.2017.07.044
18. Lesin V.S., Korovin K.V. Povyshenie effektivnosti ispol'zovaniia poputnogo neftianogo gaza pri razrabotke neftianykh mestorozhdenii [Increasing the efficiency of associated petroleum gas use in the development of oil fields]. *Akademicheskii zhurnal Zapadnoi Sibiri*, 2019, vol. 15, no. 3, pp. 32-33.
19. Kalinin S.A., Moroziuk O.A. Razrabotka mestorozhdenii vysokoviazkoi nefti v karbonatnykh kollektorakh s ispol'zovaniem dioksida ugleroda. Analiz mirovogo opyta [Using carbon dioxide to develop highly viscous oil fields in carbonate reservoirs. Global experience analysis]. *Vestnik Permskogo natsional'nogo issledovatel'skogo politekhnicheskogo universiteta. Geologiia. Neftegazovoe i gornoe delo*, 2019, no. 4, pp. 373-387. DOI: 10.15593/2224-9923/2019.4.6
20. Moroziuk O.A., Barkovskii N.N., Kalinin S.A., Bondarenko A.V., Andreev D.V. Eksperimental'nye issledovaniia vytesneniia vysokoviazkoi nefti dioksidom ugleroda iz karbonatnykh porod [Experimental study of heavy oil displacement by carbon dioxide from carbonate rocks]. *Geologiia, geofizika i razrabotka neftianykh i gazovykh mestorozhdenii*, 2019, no. 6, pp. 51-56. DOI: 10.30713/2413-5011-2019-6(330)-51-56
21. Lake L.W. Enhanced Oil Recovery Fundamentals. *Society of Petroleum Engineers*, 1985.
22. OST 153-39.2-048-2003. Neft'. Tipovye issledovaniia plastovykh fliuidov i separirovannykh neftei [OST 153-39.2-048-2003. Oil. Routine studies of reservoir fluids and separated oils]. Moscow, 2003.
23. Stalkup L.K. RTD 2(1) Oil Recovery by Miscible Displacement. *11th World Petroleum Congress, 28 August-2 September, London, UK*, 1983, January 1.
24. Helfferich F.G. et al. Theory of multicomponent, multiphase displacement in porous media. *Society of Petroleum Engineers Journal*, 1981, vol. 21, no. 01, pp. 51-62. DOI: 10.2118/8372-PA
25. Orr F.M. et al. Theory of gas injection processes. Copenhagen: Tie-Line Publications, 2007, vol. 5. 376 p.
26. Christiansen R.L. et al. Rapid measurement of minimum miscibility pressure with the rising-bubble apparatus. *SPE Reservoir Engineering*, 1987, vol. 2, no. 04, pp. 523-527. DOI: 10.2118/13114-PA
27. Rao D.N. A new technique of vanishing interfacial tension for miscibility determination. *Fluid phase equilibria*, 1997, vol. 139, no. 1-2, pp. 311-324. DOI: 10.1016/S0378-3812(97)00180-5
28. Rao D.N. et al. Application of a new technique to optimize injection gas composition for the Rainbow Keg River F Pool miscible flood. *Journal of Canadian Petroleum Technology*, 1999, vol. 38, no. 13. DOI: 10.2118/96-100
29. Adyani W.N. et al. Advanced technology for rapid minimum miscibility pressure determination (part 1). *Asia Pacific Oil and Gas Conference and Exhibition, 30 October-1 November, Jakarta, Indonesia*, 2007. DOI: 10.2118/110265-MS
30. Flock D.L., Nouar A. Parametric analysis on the determination of the minimum miscibility pressure in slim tube displacements. *The Journal of Canadian Petroleum Technology*, 1984, vol. 23, iss. 05. DOI: 10.2118/84-05-12
31. Arnold C.W., Stone H.L., Luffel D.L. Displacement of Oil by Rich-Gas Banks. *Society of Petroleum Engineers*, 1960, December 1. DOI: 10.2118/1490-G
32. Kuo S.S. Prediction of Miscibility for the Enriched-Gas Drive Process. *SPE Annual Technical Conference and Exhibition, 22-26 September, Las Vegas, Nevada*, 1985, January 1. DOI: 10.2118/14152-MS
33. Glaso O. Miscible Displacement: Recovery Tests With Nitrogen. *SPE Reservoir Engineering*, 1990, vol. 5, iss. 01, pp. 61-68. DOI: 10.2118/17378-PA
34. Boersma D.M., Hagoort J. Displacement Characteristics of Nitrogen Flooding vs. Methane Flooding in Volatile Oil Reservoirs. *SPE Reservoir Engineering*, 1994, vol. 9, iss. 04, pp. 261-265. DOI: 10.2118/20187-PA
35. Jacobson H.A. Acid Gases and Their Contribution to Miscibility. *Journal of Canadian Petroleum Technology*, 1972, vol. 11, iss. 02. DOI: 10.2118/72-02-03
36. Graue D.J., Zana E.T. Study of a Possible CO2 Flood in Rangely Field. *Journal of Petroleum Technology*, 1981, vol. 33, iss. 07, pp. 1312 - 1318. DOI: 10.2118/7060-PA
37. Frimodig J.P., Reese N.A., Williams C.A. Carbon Dioxide Flooding Evaluation of High Pour-Point, Paraffinic Red Wash Reservoir Oil. *Society of Petroleum Engineers Journal*, 1983, vol. 23, iss.e 04, pp. 587-594. DOI: 10.2118/10272-PA
38. Rutherford W.M. Miscibility Relationships in the Displacement of Oil by Light Hydrocarbons. *Society of Petroleum Engineers Journal*, 1962, vol. 2, iss. 04, pp. 340-346. DOI: 10.2118/449-PA
39. Holm L.W., Josendal V.A. Mechanisms of Oil Displacement by Carbon Dioxide. *Journal of Petroleum Technology*, 1974, vol. 26, iss. 12, pp. 1427-1438. DOI: 10.2118/4736-PA
40. Holm L.W., Josendal V.A. Effect of Oil Composition on Miscible-Type Displacement by Carbon Dioxide. *Society of Petroleum Engineers Journal*, 1982, vol. 22, iss. 01, pp. 87-98. DOI: 10.2118/8814-PA
41. Hudgins D.A., Llave F.M., Chung F.T.H. Nitrogen Miscible Displacement of Light Crude Oil: A Laboratory Study. *SPE Reservoir Engineering*, 1990, vol. 5, iss. 01, pp 100-106. DOI: 10.2118/17372-PA
42. Yellig W.F., Metcalfe R.S. Determination and Prediction of CO2 Minimum Miscibility Pressures. *Journal of Petroleum Technology*, 1980, vol. 32, iss. 01, pp. 160-168. DOI: 10.2118/7477-PA
43. Koch H.A., Hutchinson C.A. Miscible Displacements of Reservoir Oil Using Flue Gas. *Transactions of the AIME*, 1958, vol. 213, iss. 01, pp. 7-10. DOI: 10.2118/912-G
44. Yarborough L., Smith L.R. Solvent and Driving Gas Compositions for Miscible Slug Displacement. *Society of Petroleum Engineers Journal*, 1970, vol. 10, iss. 03, pp. 298-310. DOI: 10.2118/2543-PA
45. Wu R.S., Batycky J.P. Evaluation of miscibility from slim tube tests. *The Journal of Canadian Petroleum Technology*, 1990, vol. 29, no. 6, pp. 63-70. DOI: 10.2118/90-06-06
46. Kalinin S.A., Moroziuk O.A. Razrabotka mestorozhdenii vysokoviazkoi nefti v karbonatnykh kollektorakh s ispol'zovaniem dioksida ugleroda. Laboratorno-metodicheskii kompleks dlia vypolneniia issledovanii [Laboratory research of high-viscosity oil fields in carbonate reservoirs using carbon dioxide]. *Nedropolzovanie*, 2020, no. 4. pp. 369-385. DOI: 10.15593/2712-8008/2020.4.6

Библиографический список

1. Желтов Ю.П. Разработка нефтяных месторождений. – М.: Рипол Классик, 1986.
2. Промысловый опыт вытеснения нефти карбонизированной водой / А.Б. Тумасян [и др.] // Геология и разработка нефтяных месторождений востока Волго-Уральской провинции. – 1975. – С. 140.
3. Коваленко К.И. Увеличение нефтеотдачи пластов путем закачки карбонизированной воды // Нефтяное хозяйство. – 1964. – № 11. – С. 12.
4. Бабалян Г.А. Применение карбонизированной воды для увеличения нефтеотдачи. – М.: Недра, 1976. – 144 с.
5. Сургучев М.Г. Вторичные и третичные методы увеличения нефтеотдачи пластов. – М.: Недра, 1985. – 308 с.
6. Christensen J.R., Stenby E.H., Skauge A. Review of WAG Field Experience // SPE Res Eval & Eng. – 1998. – № 4 (2). – P. 97–106. SPE-71203-PA. DOI:10.2118/71203-PA
7. Afzali S., Rezaei N., Zendehboudi S. A comprehensive review on enhanced oil recovery by water alternating gas (WAG) injection // Fuel. – 2018. – Vol. 227. – P. 218–246. DOI: 10.1016/j.petrol.2017.07.066
8. Зацепин В.В. Технологические основы водогазового воздействия на пласты с трудноизвлекаемыми запасами нефти в низкопроницаемых коллекторах: дис. … канд. техн. наук. – Казань, 2017.
9. Зацепин В.В., Максутов Р.А. Современное состояние промышленного применения технологий водогазового воздействия // Нефтепромысловое дело. – 2009. – № 7. – С. 31–21.
10. Дроздов А.Н., Дроздов Н.А. Увеличение КИН: водогазовое воздействие на пласт Опыт эксплуатации насосно-эжекторной системы и пути совершенствования технологии ВГВ // Neftegaz. RU. – 2017. – № 7. – С. 70–77.
11. Screening criteria for CO2 huff'n'puff operations / L.J. Mohammed-Singh [et al.] // SPE/DOE symposium on improved oil recovery. – Society of Petroleum Engineers, 2006. DOI: 10.2118/100044-MS
12. Alagorni A.H., Yaacob Z.B., Nour A.H. An overview of oil production stages: enhanced oil recovery techniques and nitrogen injection // International Journal of Environmental Science and Development. – 2015. – Vol. 6, № 9. – P. 693–701. DOI: 10.7763/IJESD.2015.V6.682
13. Enhanced oil recovery with high-pressure nitrogen injection / D. Denney [et al.] // Journal of petroleum technology. – 2001. – Vol. 53, № 01. – P. 55–56. DOI: 10.2118/62547-MS
14. Blunt M., Fayers F.J., Orr Jr F.M. Carbon dioxide in enhanced oil recovery // Energy Conversion and Management. – 1993. – Vol. 34, № 9–11. – P. 1197–1204. DOI: 10.1016/0196-8904(93)90069-M
15. Глазова В.М., Рыжик В.М. Применение двуокиси углерода для повышения нефтеотдачи пластов за рубежом. – М.: ВНИИОЭНГ, 1986. – 45 с.
16. The mechanism of flue gas injection for enhanced light oil recovery / O.S. Shokoya [et al.] // J. Energy Resour. Technol. – 2004. – Vol. 126, № 2. – P. 119–124. DOI: 10.1115/1.1725170
17. Bender S., Akin S. Flue gas injection for EOR and sequestration: Case study // Journal of Petroleum Science and Engineering. – 2017. – Vol. 157. – P. 1033–1045. DOI: 10.1016/j.petrol.2017.07.044
18. Лесин В.С., Коровин К.В. Повышение эффективности использования попутного нефтяного газа при разработке нефтяных месторождений // Академический журнал Западной Сибири. – 2019. – Т. 15, № 3. – С. 32–33.
19. Калинин С.А., Морозюк О.А. Разработка месторождений высоковязкой нефти в карбонатных коллекторах с использованием диоксида углерода. Анализ мирового опыта // Вестник Пермского национального исследовательского политехнического университета. Геология. Нефтегазовое и горное дело. – 2019. – № 4. – С. 373–387. DOI: 10.15593/2224-9923/2019.4.6
20. Экспериментальные исследования вытеснения высоковязкой нефти диоксидом углерода из карбонатных пород / О.А. Морозюк, Н.Н. Барковский, С.А. Калинин, А.В. Бондаренко, Д.В. Андреев // Геология, геофизика и разработка нефтяных и газовых месторождений. – 2019. – № 6. – С. 51–56.
21. Lake L.W. Enhanced Oil Recovery Fundamentals. – Society of Petroleum Engineers, 1985. DOI: 10.30713/2413-5011-2019-6(330)-51-56
22. ОСТ 153-39.2-048-2003. Нефть. Типовые исследования пластовых флюидов и сепарированных нефтей. – М., 2003.
23. Stalkup L.K. RTD 2(1) Oil Recovery by Miscible Displacement // World Petroleum Congress. – 1983. – January 1.
24. Theory of multicomponent, multiphase displacement in porous media / F.G. Helfferich [et al.] // Society of Petroleum Engineers Journal. – 1981. – Vol. 21, № 01. – P. 51–62. DOI: 10.2118/8372-PA
25. Theory of gas injection processes / F.M. Orr [et al.]. – Copenhagen: Tie-Line Publications, 2007. – Vol. 5. – 376 с.
26. Rapid measurement of minimum miscibility pressure with the rising-bubble apparatus / R.L. Christiansen [et al.] // SPE Reservoir Engineering. – 1987. – Vol. 2, № 04. – P. 523–527. DOI: 10.2118/13114-PA
27. Rao D.N. A new technique of vanishing interfacial tension for miscibility determination // Fluid phase equilibria. – 1997. – Vol. 139, № 1–2. – P. 311–324. DOI: 10.1016/S0378-3812(97)00180-5
28. Application of a new technique to optimize injection gas composition for the Rainbow Keg River F Pool miscible flood / D.N. Rao [et al.] // Journal of Canadian Petroleum Technology. – 1999. – Vol. 38, № 13. DOI: 10.2118/96-100
29. Advanced technology for rapid minimum miscibility pressure determination (part 1) / W.N. Adyani [et al.] // Asia Pacific Oil and Gas Conference and Exhibition. – Society of Petroleum Engineers, 2007. DOI: 10.2118/110265-MS
30. Flock D.L., Nouar A. Parametric analysis on the determination of the minimum miscibility pressure on slim tube displacements // The Journal of Canadian Petroleum Technology. – 1984. – Vol. 23, № 05. – P. 80–86. DOI: 10.2118/84-05-12
31. Arnold C.W., Stone H.L., Luffel D.L. Displacement of Oil by Rich-Gas Banks // Society of Petroleum Engineers. – 1960. – December 1. DOI: 10.2118/1490-G
32. Kuo S.S. Prediction of Miscibility for the Enriched-Gas Drive Process // Society of Petroleum Engineers. – 1985. – January 1. DOI:10.2118/14152-MS
33. Glaso O. Miscible Displacement: Recovery Tests With Nitrogen // Society of Petroleum Engineers. – 1990. – February 1. DOI:10.2118/17378-PA
34. Boersma D.M., Hagoort J. Displacement Characteristics of Nitrogen Flooding vs. Methane Flooding in Volatile Oil Reservoirs // Society of Petroleum Engineers. – 1994. – November 1. DOI:10.2118/20187-PA
35. Jacobson H.A. Acid Gases And Their Contribution to Miscibility // Petroleum Society of Canada. – 1972. – April 1. DOI:10.2118/72-02-03
36. Graue D.J., Zana E.T. Study of a Possible CO2 Flood in Rangely Field // Society of Petroleum Engineers. – 1981. – July 1. DOI:10.2118/7060-PA
37. Frimodig J.P., Reese N.A., Williams C.A. Carbon Dioxide Flooding Evaluation of High Pour-Point, Paraffinic Red Wash Reservoir Oil // Society of Petroleum Engineers. – 1983. – August 1. DOI:10.2118/10272-PA
38. Rutherford W.M. Miscibility Relationships in the Displacement of Oil By Light Hydrocarbons // Society of Petroleum Engineers. – 1962. – December 1. DOI:10.2118/449-PA
39. Holm L.W., Josendal V.A. Mechanisms of Oil Displacement By Carbon Dioxide // Society of Petroleum Engineers. – 1974. – December 1. DOI:10.2118/4736-PA
40. Holm L.W., Josendal V.A. Effect of Oil Composition on Miscible-Type Displacement by Carbon Dioxide // Society of Petroleum Engineers. – 1982. – February 1. DOI:10.2118/8814-PA
41. Hudgins D.A., Llave F.M., Chung F.T.H. Nitrogen Miscible Displacement of Light Crude Oil: A Laboratory Study // Society of Petroleum Engineers. –1990. – February 1. DOI:10.2118/17372-PA
42. Yellig W.F., Metcalfe R.S. Determination and Prediction of CO2 Minimum Miscibility Pressures // Society of Petroleum Engineers. – 1980. – January 1. DOI:10.2118/7477-PA
43. Koch H.A., Hutchinson C.A. Miscible Displacements of Reservoir Oil Using Flue Gas // Society of Petroleum Engineers. – 1958. – December 1. DOI:10.2118/912-G
44. Yarborough L., Smith L.R. Solvent and Driving Gas Compositions for Miscible Slug Displacement // Society of Petroleum Engineers. – 1970. – September 1. DOI:10.2118/2543-PA
45. Wu R.S., Batycky J.P. Evaluation of miscibility from slim tube tests // The Journal of Canadian Petroleum Technology. – 1990. – Vol. 29, № 6. – P. 63–70. DOI: 10.2118/90-06-06
46. Калинин С.А., Морозюк О.А. Разработка месторождений высоковязкой нефти в карбонатных коллекторах с использованием диоксида углерода. Лабораторно-методический комплекс для выполнения исследований // Недропользование. – 2020. – № 4. – С. 369–385. DOI: 10.15593/2712-8008/2020.4.6