ISSN 2712-8008
Volume / Том 21 №4 2021
Journal Homepage: http://vestnik.pstu.ru/geo/

Perm Journal of Petroleum and Mining Engineering

UDC 622.551.2.02
Article / Статья

Laboratory Investigations of Using High CO_2 Associated Petroleum Gas for Injection at the Tolum Field

Ruslan R. Mardamshin[1], Andrey V. Stenkin[1], Stanislav A. Kalinin[2], Oleg O. Morozyuk[3], Sergei A. Kalinin[2], Andrey S. Skvortsov[2], Gennadiy A. Usachev[4], Dmitry A. Mett[4]

[1]LUKOIL-Western Siberia LLC (16a Lenina Str., Urai, Khanty-Mansi Autonomous Area, 628285, Russian Federation)
[2]PermNIPIneft Branch of LUKOIL-Engineering LLC in Perm (3a Permskaya Str., Perm, 614015, Russian Federation)
[3]Tyumen Oil Research Center LLC (42 Maxim Gorky Str., Tyumen, 625048, Russian Federation)
[4]LUKOIL-Engineering LLC (bldg. 1, 3 Pokrovsky Boulevard., Moscow, 109028, Russian Federation)

Лабораторные исследования применения попутного нефтяного газа с высоким содержанием CO_2 для закачки на Толумском месторождении

Р.Р. Мардамшин[1], А.В. Стенькин[1], С.А. Калинин[2], О.А. Морозюк[3], С.А. Калинин[2], А.С. Скворцов[2], Г.А. Усачев[4], Д.А. Метт[4]

[1]ООО «ЛУКОЙЛ-Западная Сибирь» (Россия, 628285, Ханты-Мансийский автономный округ, г. Урай, ул. Ленина, 116а)
[2]Филиал ООО «ЛУКОЙЛ-Инжиниринг» «ПермНИПИнефть» в г. Перми (Россия, 614015, г. Пермь, ул. Пермская, 3а)
[3]ООО «Тюменский нефтяной научный центр» (Россия, 625048, г. Тюмень, ул. Максима Горького, 42)
[4]ООО «ЛУКОЙЛ-Инжиниринг» (Россия, 109028, г. Москва, Покровский б-р, 3 строение 1)

Received / Получена: 19.04.2021. Accepted / Принята: 30.07.2021. Published / Опубликована: 01.10.2021

Keywords:
gas injection, associated petroleum gas utilization, filtration experiments, laboratory investigations, displacement ratio, miscible displacement, relative phase permeabilities.

Various enhanced oil recovery technologies based on the injection of various gases into the reservoir have been successfully used abroad, especially in the United States, since the middle of the 20th century. Carbon dioxide has received the greatest application as a reservoir influencing agent, since it can dissolve in large amounts in oil under reservoir conditions, and also demonstrates a phase behavior that is convenient from a process-oriented point of view. However, in Russia the technology of CO_2 injection in order to increase oil recovery has not become widespread due to the absence of large natural sources of CO_2. Nevertheless, due to the need to comply with the terms of the Paris Agreement on reducing greenhouse gas emissions, LUKOIL has been paying more and more attention to the development of technologies for utilisation of technogenic greenhouse gas, including associated petroleum gas.
This paper presents the results of laboratory investigations to assess the prospects for the application of an enhanced oil recovery technology at the Tolumskoye field by injecting the high CO_2 associated petroleum gas, the source of which is the Semividovskaya group of fields. The effect of concentration of associated petroleum gas on reservoir oil properties was studied, the mode of oil displacement by associated petroleum gas was assessed, ratios of oil displacement by water and the model of associated petroleum gas and relative phase permeabilities on core models of the Tolumskoye field were determined. The results of laboratory investigations were used for the further stage of hydrodynamic modeling, which was carried out to select the most optimal associated gas injection technology and to perform a technical and economic assessment of associated gas injection technology to enhance oil recovery from hard-to-recover reserves of the Tolumskoye field.

Ключевые слова:
закачка газа, утилизация попутного нефтяного газа, фильтрационные эксперименты, лабораторные исследования, коэффициент вытеснения, смешивающееся вытеснение, относительные фазовые проницаемости.

Различные технологии повышения нефтеотдачи, основанные на закачке в пласт различных газов, успешно используются за рубежом, особенно в США, начиная с середины XX в. Наибольшее применение в качестве агента воздействия на залежь получил диоксид углерода, поскольку способен в большом количестве растворяться в нефти при пластовых условиях, а также обладает удобным с технологической точки зрения фазовым поведением. Однако в России технология закачки CO_2 с целью увеличения нефтеотдачи не получила широкого распространения по причине отсутствия крупных естественных источников CO_2. Тем не менее в последнее время в связи с необходимостью соблюдения условий Парижского соглашения по снижению выбросов парниковых газов компанией «ЛУКОЙЛ» все больше внимания уделяется развитию технологий утилизации техногенных парниковых газов, в том числе попутного нефтяного газа.
Представлены результаты лабораторных исследований по оценке перспектив применения технологии повышения нефтеотдачи Толумского месторождения путем закачки попутного нефтяного газа с высоким содержанием CO_2, источником которого служит Семивидовская группа месторождений. Изучено влияние концентрации попутного нефтяного газа на свойства пластовой нефти, выполнена оценка режима вытеснения нефти попутным нефтяным газом, определены коэффициенты вытеснения нефти водой и моделью попутного нефтяного газа и относительные фазовые проницаемости на керновых моделях пласта Толумского месторождения. Результаты лабораторных исследований использовались для дальнейшего этапа гидродинамического моделирования, выполняемого для выбора наиболее оптимальной технологии закачки попутного нефтяного газа и выполнения технико-экономической оценки применения технологии закачки попутного нефтяного газа для повышения нефтеотдачи трудноизвлекаемых запасов Толумского месторождения.

Ruslan R. Mardamshin - Head of the Enhanced Oil Recovery Technology Department (tel.: +007 (346) 764 2614, e-mail: Ruslan.Mardamshin@lukoil.com).
Andrey V. Stenkin (Author ID in Scopus: 57206473477) – Deputy General Director for the Field Development - Chief Geologist, Ph.D in Geological and Mineralogical Sciences (tel.: +007 (346) 764 2614, e-mail: Andrey.Stenkin@lukoil.com).
Stanislav A. Kalinin (Author ID in Scopus: 57194691912) – Head of the Research Department of Thermal Stimulation Methods (tel.: +007 (342) 717 01 66, e-mail: stanislav.kalinin@pnn.lukoil.com). The contact person for correspondence.
Oleg O. Morozyuk (Author ID in Scopus: 57220034214) – expert, PhD in Engineering Sciences (tel.: +007 (342) 717 01 66, e-mail: oamorozyk@gmail.com).
Sergei A. Kalinin – II category Engineer of the Research Department of Chemical Core EOR Methods (tel.: +007 (342) 717 01 66, e-mail: Sergej.Kalinin@pnn.lukoil.com).
Andrey S. Skvortsov (Author ID in Scopus: 57194692889) – II category Engineer of the Research Department of Thermal Stimulation Methods (tel.: +007 (342) 717 01 66, e-mail: Andrej.Skvortsov@pnn.lukoil.com).
Gennadiy A. Usachev (Author ID in Scopus: 57211299608) – Head of the High-Viscosity and Hard-to-Recover Oil Reserve Development Department (tel.: +007 (495) 627 44 44, e-mail: Gennadiy.Usachev@lukoil.com).
Dmitry A. Mett – Head of the Geological Hard-to-Recover Object Exploration Department, Doctor of Engineering.

Мардамшин Руслан Рамзисович – начальник отдела технологий повышения нефтеотдачи (тел.: +007 (346) 764 2614, e-mail: Ruslan.Mardamshin@lukoil.com).
Стенькин Андрей Вениаминович – заместитель генерального директора по разработке месторождений, главный геолог, кандидат геолого-минералогических наук (тел.: +007 (346) 764 2614, e-mail: Andrey.Stenkin@lukoil.com).
Калинин Станислав Александрович – начальник отдела исследований тепловых методов воздействия на пласт (тел.: +007 (342) 717 01 66, e-mail: stanislav.kalinin@pnn.lukoil.com). Контактное лицо для переписки.
Морозюк Олег Александрович – эксперт, кандидат технических наук (тел.: +007 (342) 717 01 66, e-mail: oamorozyk@gmail.com).
Калинин Сергей Александрович – инженер II категории отдела исследований химических методов повышения нефтеотдачи пласта на керне (тел.: +007 (342) 717 01 66, e-mail: Sergej.Kalinin@pnn.lukoil.com).
Скворцов Андрей Сергеевич – инженер II категории отдела исследований тепловых методов воздействия на пласт (тел.: +007 (342) 717 01 66, e-mail: Andrej.Skvortsov@pnn.lukoil.com).
Усачев Геннадий Александрович – начальник управления разработки высоковязких и трудноизвлекаемых запасов нефти (тел.: +007 (495) 627 44 44, e-mail: Gennadiy.Usachev@lukoil.com).
Метт Дмитрий Александрович – начальник отдела геологического изучения трудноизвлекаемых объектов, доктор технических наук.

Please cite this article in English as:
Mardamshin R.R., Stenkin A.V., Kalinin S.A., Morozyuk O.A., Kalinin S.A., Skvortsov A.S., Usachev G.A., Mett D.A. Laboratory investigations of using high CO_2 associated petroleum gas for injection at the Tolum field. *Perm Journal of Petroleum and Mining Engineering*, 2021, vol.21, no.4, pp.163-170. DOI: 10.15593/2712-8008/2021.4.3

Просьба ссылаться на эту статью в русскоязычных источниках следующим образом:
Лабораторные исследования применения попутного нефтяного газа с высоким содержанием CO_2 для закачки на Толумском месторождении / Р.Р. Мардамшин, А.В. Стенькин, С.А. Калинин, О.А. Морозюк, С.А. Калинин, А.С. Скворцов, Г.А. Усачев, Д.А. Метт // Недропользование. – 2021. – Т.21, №4. – С.163–170. DOI: 10.15593/2712-8008/2021.4.3

Introduction

Various enhanced oil recovery technologies based on the injection of various gases into the reservoir have been successfully used abroad, especially in the United States, since the middle of the 20th century. [1] Carbon dioxide has received the greatest application as a reservoir influencing agent, since it can dissolve in large amounts in oil under reservoir conditions, and also demonstrates a phase behavior that is convenient from a process-oriented point of view. However, in Russia the technology of CO_2 injection in order to increase oil recovery has not become widespread due to the absence of large natural sources of CO_2. Nevertheless, due to the need to comply with the terms of the Paris Agreement on reducing greenhouse gas emissions, LUKOIL has been paying more and more attention to the development of technologies for utilization of technogenic greenhouse gas, including associated petroleum gas (APG) [2, 3].

APG mining rate is constantly growing in Russia due to bringing new fields into development and the growth of the gas factor in the products mined from ultra-mature fields [4]. According to [5], 78.6 m^3 of APG was mined in Russia in 2015, and the flared volume constituted 10 billion m^3, which is comparable to the annual gas consumption of some European countries [6]. APG flaring is a reason of the high carbon dioxide and other greenhouse gas emission, which has a negative impact on the environment. The introduction of a border tax for the greenhouse gas emissions with the state's APG flaring fines will induce an additional load on the oil mining companies [7, 8]. Therefore, finding the optimal option for APG utilization to reduce the environmental impact and to minimize the financial expenses of the company is an important task today.

There are different common way of reducing the APG emissions [9, 10]. Keeping in mind the composition of APG from the Semividovskaya group of fields where carbon dioxide is the main component, and considering the geographical proximity of the development site, APG injection into the reservoirs to boost oil recovery appears the most reasonable way of APG utilization.

Depending on the pressure, temperature, oil and gas agent composition, both miscible and immiscible oil displacement may develop [11–13]. The gas agent composition makes a significant impact on the minimal miscibility pressure rate, and, therefore, on the possibility of using the miscible oil displacement. This way, keeping in mind that the oil composition, temperature and pressure conditions of the fields are unique, the determination of the proper method and completeness of oil displacement with a gas agent appears as a purely experimental task that requires a series of laboratory surveys.

Previously, the authors published the results of laboratory tests [14] for the determination of the minimum miscibility pressure of the reservoir oil from the Tolumskoye field. This paper presents the results of the filtration experiments carried out on the core reservoir models for the evaluation of the possibility of APG utilization to enhance oil recovery from hard-to-recover reserves of the Eastern formation of the Tolumskoye field located in Western Siberia.

General Information of the Tolumskoye Field

The Tolumskoye oil and gas field is located in the Kodinsk District of the Khanty-Mansi Autonomous Okrug of the Tyumen Region, 50 km northeast from Uray town. The industrial oil and gas potential of the field is associated with the Jurassic coastal Abalakskaya suite formations (J3 reservoir P), continental Tyumenskaya suite deposits (J2 reservoir T) and the Palaeozoic weathering crust deposits (DUK). The geological profile of the field is presented in Fig. 1.

In the field, there is one development object P + T + KV, productive reservoir depth of 1788–1954 m, current net-weighed reservoir pressure is 14 MPa, current AB_1 category oil recovery factor is 0.390, recovery from the initial recoverable reserves (IRR) is 93.8 %, IRR production rate – 0.5% with the water cut of 97.8 %. The mean net oil thickness value is 6 m, net-to-gross sand ratio – 0.62 unit fractions, number of permeable intervals – 4.8 units, porosity factor – 0.207, permeability factor varied from 1.5 to 603 mD with the mean value of 118 mD [15]. The oil deposits of the high-permeable reservoirs are almost completely exhausted, and the currently mined oil is provided by the medium-permeable reservoirs.

For the further successful development of the immovable oil reserves from the low productive reservoirs, the employment of the following main geological and technical operations (GTO): hydraulic fracturing (HF), bottomhole zone treatment (BZT), re-perforation and application of diverter technologies. Due to the high production rate, the field requires new approaches to the formation pressure maintenance and the use of displacement agents.

One of the priority trends in raising the final oil recovery rate is the injection of APG from the Semividovskaya field group.

Associated Petroleum Gas Source

The oil recovered from the nearby North-Semividovskoye and Western-Semividovskoye fields has a high CO_2 content in APG constituting 73.4 % vol. Detailed composition of APG from the Semividovskaya field group is presented in the table below.

The well product mined at these fields is transported with the existing gas and oil transportation system to BPS-4 located in the nearest proximity to the well clusters of the Tolumskoye field. The maximum distance from the APG source to the perspective sites is 7 km. The system of APG transportation from the Semividovskoe field group to the BPS-4 of the Tolumskoye field is presented in Fig. 2.

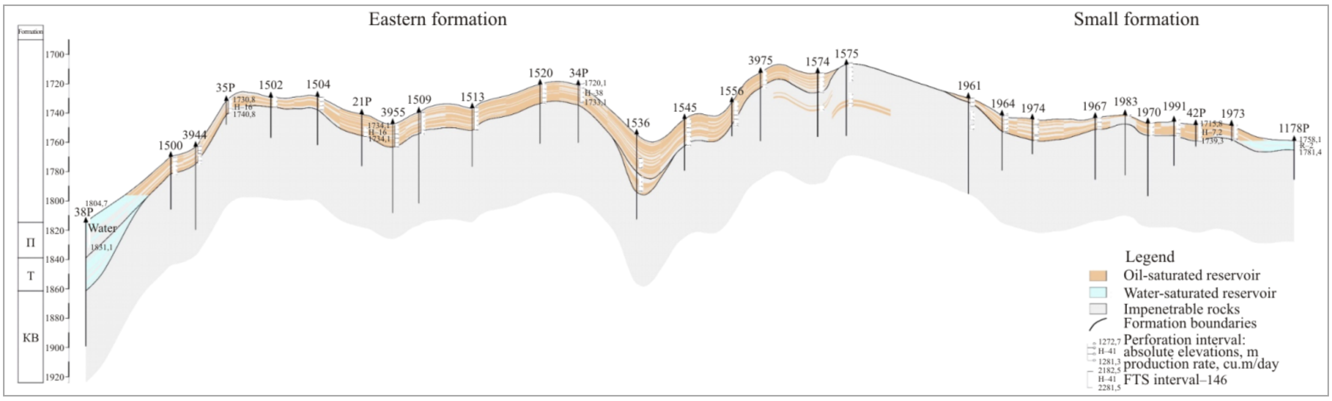

Fig. 1. Geological profile on the well line 38P–1500–3944–35P–1502–1504–21P–3955–1509–1513–1520–34P–1536–1545–1556–3975–1574–1575–1961–1964–1974–1967–1983–1970–1991–42P–1973–1178P. Reservoirs P, T, KV

Selection of Sites for Associated Petroleum Gas Injection

Due to the sufficient amount of the APG with the high CO_2 content to BPS-4, the application of the gas stimulation (GS) or water-gas stimulation (WGS) on the Eastern formation of the Tolumskoye field for the following reasons:

– the formation has the largest area and the volume of reserves among the sites nearest to the APG source;

– maximum annual oil recovery from the formation constitute over 200 thousand tons, which matches a significant share of the recovered APG;

– the formation has a better developed infrastructure compared to other formations in the nearest proximity to the APG source.

The reservoir top in the formation area is opened with the wells at the depths with the absolute elevation varying from –1690.7 to –1791.7 m, the difference between the reservoir top elevations is 101 m. Generally, the reservoir top appears to dip from the Pre-Jurassic base noses towards the downfold. The total and net pay thickness of the reservoir varies along the formation in a large diapason, from 0 on the pinch-out line to 34.8 and 21.0 m, respectively. The net pay oil saturated thicknesses vary in different wells from 0.6 to 19.0 m, constituting 8.9 m on average. The water-oil contact (WOC) is opened with four wells at the absolute elevations from –1796 to –1800.8 m, and considered to be located at the absolute elevation of –1796 m.

At the present moment, all reservoirs, P, T, and KV, are under development according to the current system. The reservoir deposits within the given formation are opened with 175 wells; 179 of them open the net oil pay zone (NOPZ), and seven open the water-oil zone (WOZ). The WOZ occupies 15 % of the total formation area.

Considering the current Eastern formation development system, there are four options of pilot project (PP) sites with the transformation of three water injection wells (three options) and one production well into gas injection wells. For every site, the "reacting network" of production wells was determined as 5-, 6-, and 7-point development systems.

The PP site selection depends on the system of managing every formation and the deposit as a whole, the net pay thickness, the opening of oil-saturated thicknesses with wells, unevenness of the site's area, section, and remaining oil-in-place. Based on the mentioned geological, physical criteria and the peculiarities of the well arrangement in the structure of reservoir P of the Tolumskoye field, four sites of the Eastern formation were selected for test injections: block 2, block 3, and block 4 of the eastern part and block 4 of the western part (Fig. 3).

The work included a thorough analysis of the project documentation on the development of the North-Semividovskoye and Tolumskoye deposits for the PP site selection and feasibility study of the candidate wells for the possible implementation of the GS/WGS of the reservoirs with a high CO_2 content in the associated petroleum gas.

To increase the oil recovery rate of the reservoirs not covered by the active injection in the current development system, for the implementation of the GS/WGS technologies at the aforementioned fields, it appears relevant to consider:

– running a set of operations (laboratory core tests) for the justification of the increase in the oil displacement factor with GS/WGS with APG injection in the conditions of formation P of the Tolumskoye field;

– specification of the geological and recoverable (drainable) oil reserves of formations P, T, KV in the formations of the North-Semividovskoye and Tolumskoye fields. This criterion helps to correctly assess the operating costs and the economic benchmarks of the APG injection pilot project for further scaling;

– running pilot projects on APG injection at one of the sites in the Eastern formation of the Tolumskoye field. In case of successful completion of the pilot projects for the implementation of the GS/WGS technologies in the Eastern formation for APG injection at the industrial scale; PP sites in the Southern and Lesser formations of the Tolumskoye field.

Composition of the associated petroleum gas of the Semividovskaya field group

Component	Content		Regulatory document
	% vol.	% weight	
Methane (CH_4)	17.250	7.01	[16]
Ethane (C_2H_4)	1.99	1.53	
Propane (C_3H_8)	2.72	3.09	
Isobutane (iC_4H_{i6})	0.46	0.70	
N-butane (nC_4H_{i6})	1.25	1.90	
Isopentane (iC_5H_{12})	0.28	0.54	
N-pentane (C_5H_{12})	0.41	0.79	
Hexanes (C_6H_{14})	0.33	0.79	
Carbon dioxide (CO_2)	73.40	82.30	
Nitrogen (N_2)	1.89	1.34	
Helium (He)	0.021	0.0021	
Hydrogen (H_2)	0.0026	0.00013	

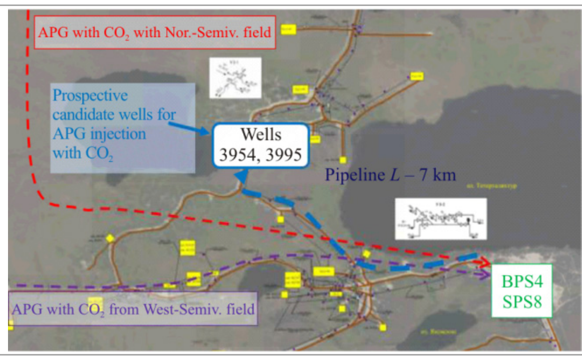

Fig. 2. APG transportation from the Semividovskaya field group to BTS-4 of the Tolumskoye field

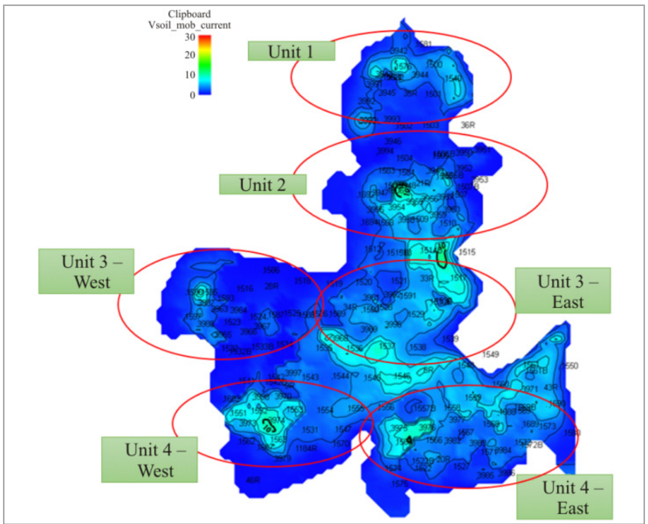

Fig. 3. Potential sites for APG injection at the Eastern formation of the Tolumskoye field

Ways of Associated Petroleum Gas Use

Among the ways of APG use, one of the common ones is the APG injection into the reservoir for the formation pressure maintenance. Thus, in Gazprom Neft, the development of oil fields with oil rims and a gas cap, the technology of reverse APG injection into the reservoir gas cap is used [17, 18]. The essence of the technology is that the APG is separated from crude oil, treated with a required method and injected into the reservoir gas cap to maintain the formation pressure. The first APG injection project was carried out at the Novoportovskoye field. A compressor station with an integrated gas treatment unit, as well as ten horizontal gas injection wells at two well clusters were installed at the field. The oil injection began at the end of October 2017. The project capacity of the station is 19–20 million m^3 of gas per day.

The oil recovery can be also increased by means of miscible oil displacement with APG injection. The miscible oil displacement planned to be introduced at the Tolumskoye field is potentially possible due to the high CO_2 content in the chemical composition of the APG found at the Semividovskaya field group. The previous laboratory tests [14] proved that the miscible oil displacement is achieved at 14.8 MPa.

There are different variations of gas injection for the implementation of the miscible oil displacement method. One of the options of APG use for the oil recovery stimulation is using the gas as an injection agent in the water-gas stimulation technology (WGS). The essence of the technology is the injection of water and gas rims of a certain size into the oil-saturated reservoir to unify the oil displacement front and, depending on the geological and physical conditions of the site and the composition of the injected gas and the formation oil, to achieve the miscible oil displacement.

Depending on the technology type, water and gas can be injected in different ways: simultaneously [19], gradually (WAG) [20], as water and gas rims [21] and as water and gas mist (WGM) [22]. There are different WGS variations that appeared as a result of developing the idea on the alternate water and gas injection, as, for example, alternate WGM injection with a periodic variation of the gas phase particle size [23]. There is also a WGS technology suggested by A.H. Mirzadzhanzade and I.M. Ametov, later developed by the representatives of the A.H. Mirzadzhanzde school, where the mist phase (gas) in the water and gas mix is present as microbubbles of gas [24, 25].

The first WGS project in Russia was implemented at the Bori-Su field in the Republic of Chechnya, from 1945 to 1955 [26, 27]. The dry hydrocarbon gas and water were simultaneously injected into the reservoir border zone in the area drilled under the 7-point well distribution scheme in the period from 1945 to 1954. From 1954 to 1955, only water injection was carried out. Simultaneous water and gas injection stimulated extra oil recovery rates.

The largest WGS project in Russia is the industrial experiment at the Samotlorskoye field [28]. In the 1980–1990's, the classical WGS option, i.e. the gradual APG and water rim injection was implemented at the field. Due to the need for reducing the high capital costs of the alternate injection, in 2006–2008, the option of injecting water and gas mist (WGM) created with special ejection-dispersion units was considered. The WGM injection effect continued till the end of 2010. In total, the additionally mined volume constituted 24.2 thousand tons of oil, i.e. 11.2 % of the total oil recovery in the experimental site.

The paper [29] describes the water and gas injection into the reservoir for APG utilisation based on the project of the Sredne-Khulymskoye field (RITEK, OJSC). The suggested technical solution is based on using massively produced equipment. The developed process flow did not only increase the oil recovery factor and helped utilizing the associated petroleum gas, but also contributed flexibility to the changing water/gas ratio in the water and gas mix injected into the reservoir.

There are also some examples of using greenhouse gases, and, particularly, CO_2, for the oil recovery stimulation and possible gas utilization in cyclic gas injection (Huff'n'Puff) [30–32я This technology requires the gas agent to be injected into the reservoir in cycles consisting of three stages: 1) gas injection until a certain pressure is reached; 2) well closure for the injected gas to dissolve in the reservoir oil; 3) oil recovery with the injected gas.

Cyclic gas injection can be used in both high-gravity [33–35] and low-gravity high-viscosity oil fields [36–38]. The greatest effect is reached at the high-gravity oil when the minimum miscibility pressure is reached at the gas injection stage [39].

The first [40] successful pilot project for the CO_2 injection for oil recovery stimulation in Russia was carried out by RITEK, OJSC, at the Maryinskoye high-viscosity oil field in the Samara Region [41]. According to the PP results, the CO_2 injection increased the well production rate and aided the commissioning of the previously idle wells. The PP results' analysis showed that the effect was caused by the reduction of the oil viscosity and swelling due to the CO_2 injection, as well as the bottomhole zone cleaning.

Laboratory Test Method

The laboratory tests were based on the recombined reservoir oil model of the Tolumskoye field. The recombined oil model was prepared by mixing the previously degassed wellhead oil sample with the model of the dissolved oil gas of the Tolumskoye field in a certain proportion. See more detailed description of the recombined oil model preparation in [14].

The displacement agent in the experiments was the APG model of the Semividovskaya field group. This APG is peculiar for the high carbon dioxide content reaching 70 % vol. The APG model was prepared by mixing the pure gases contained in the actual APG. See more details about the method and the gas model preparation procedure in [42]. The APG model adequacy was verified by means of comparing the APG model composition chromatography results with the actual composition of the APG from the Semividovskaya field group. The results are presented in the previously published paper [14].

For the determination of the physical and chemical properties of the recombined oil model (saturation pressure, viscosity, density, volume factor), the standard set of PVT tests based on the [43] data was carried out.

After the preparation procedures, the recombined oil model and the APG model were transferred to the experimental filtration unit.

The core models of the Tolumskoye field reservoir were compiled of the reference core standards selected from the productive field intervals. The core sample preparation included the following operations: the samples were dried in a thermal cabinet to a fixed mess, the gas permeability of the core samples, the vacuum saturation of the samples with the reservoir water model were determined; the sample porosity was measured with the fluid saturation method and the residual water content of the samples was created with the semipermeable membrane method. Based on the filtration-volumetric properties (FVP) of the samples, the reservoir core models were formed in accordance with the [44] data with similar characteristics for further comparison of the results.

The oil displacement experiments were carried out on the complex core models of four gas permeability groups (17, 85, 150 and $260 \cdot 10^{-3}$ μm^2) using different displacement agents and injection methods, such as oil displacement with water, APG, displacement with water followed by APG and water rims, and oil recovery under cyclic APG injection.

In all of these cases, the oil was displaced with a constant volumetric flow rate of the displacement agent of 0.12 cm^3/min until the termination of oil release from the reservoir core models. The oil displacement factor was calculated as a ratio of the measured displaced oil volume to the volume of oil initially contained in the reservoir model with due consideration of its volume factor.

Oil displacement by the alternate gas and water injection was carried out in two stages: at the first stage, the oil was displaced by water to the complete waterflooding of the fluid flow released from the reservoir core models; at the second stage, the displacement was achieved by means of alternate injection of APG and water rims equal in volume ($0.25\,V_{pore}$ model). The gas and water rims were injected to the total waterflooding of the fluid flow released from the model.

The experiments for modelling the oil recovery in the cyclic APG injection (Huff'n'Puff) were performed in two variants. In the first variant, the cyclic APG injection was done on the reservoir model with residual oil saturation after preliminary displacement of oil with water. In the second, the cyclic gas injection was done on a model with initial oil saturation (and bound water). In each experiment, five "injection – saturation – recovery" cycles were done. At the APG injection stage, the pressure in the reservoir model was raised from 10 to 14.8 MPa, and at the same moment the injected gas volume was recorded. After that, the model was closed for saturation for 12 hours. After the saturation stage, the input flange of the model was opened for fluid recovery, and the pressure was reduced step by step by manipulating the backpressure valve. The fluids were recovered to the moment of pressure reduction to the initial pore value (10 MPa) in the reservoir model. At the recovery stage, the pressure reduction rate was the same in both experiments.

As a rule, the miscible displacement is modelled in a hydrodynamic simulator based on the Todd – Longstaff filtration model [45], which is a three-component system of the reservoir oil, injected gas and water. The miscibility of the oil phase and the solvent phase is set with the miscibility factor ω which, depending on the phase miscibility degree, can be set from 0 (oil and solvent are totally immiscible phases) to 1 (oil and solvent are totally miscible phases). In this situation, the injected gas and reservoir oil are supposed to be miscible in any proportion, and there is only one hydrocarbon phase in the reservoir at a time. This way, the experiments for the relative phase permeability determination in the "oil + APG – water" system were carried out at the formation temperature and the pressure rate at which the APG was completely dissolved in oil. The relative permeability values were determined for three APG concentrations in oil: 0, 10, and 20 %. The relative permeability measurement experiments were based on the stationary filtration method in accordance with paper [46].

Oil Displacement with Water and APG Model

The results of the experiments on the determination of the factors of oil displacement with water and the APG model on the reservoir core models with different gas permeability under the current reservoir conditions (10 MPa and 91 ºC) are presented in Fig. 4 and 5.

Based on the Fig. 4 data, we see that under the low permeability (around $17 \cdot 10^{-3}$ μm^2), both in the displacement of oil with water and gas, the greatest oil displacement factor is achieved. As the permeability value increases from 85 to $260 \cdot 10^{-3}$ μm^2 (mD), the displacement factor tends to grow: from 0.481 to 0.615 unit fractions for displacement with water and from 0.476 to 0.570 unit fractions for displacement with gas. At the same time, for the displacment with gas, under the higher permeability values lower displacement factors are typical; it is explained by the greater mobility of gas compared with water and faster gas breakthrough into the reservoir model.

The reservoirs with the permeability value of $85 \cdot 10^{-3}$ μm^2 (mD) were used for the experiments on the displacement of oil with the APG model under the pressures of 10 MPa (current average weighed reservoir pressure) and 14.8 MPa (minimum miscibility pressure, MMP [14]). According to the experiment results, under otherwise equal conditions, in the oil displacement with APG under the pore pressure equal to MMP, the oil displacement factor is 0.651 unit fractions, which is 0.175 unit fractions higher compared to the oil displacement with APG under 10 MPa. This result witnesses that the conditions of the Tolumskoye field allow to increase the oil recovery value with APG injection provided that the MPP is achieved.

Fig. 5 demonstrates the dependences of the extreme pressure difference values between the ends of the core models on their permeability values.

As a rule, the displacement of oil with gas in the low-permeability reservoir models causes much lower pressure differences, compared to the displacement with water (see Fig. 5), which indicates the potential for the development of the low-permeability reservoir zones that cannot be involved into water injection development due to the high hydrodynamic resistance values.

Oil Displacement with Alternate Water and Gas Injection

The results of calculation of the factor of oil displacement with water followed by the model APG rim and water displacement are presented in Fig. 6.

As can be concluded from the Fig. 6 data, after pumping of 2.6 V_{pore} of the model with water, in both experiments the oil displacement factor was practically the same: 0.592 unit fractions at 14.8 MPa and 0.583 unit fractions at 10 MPa. Further oil displacement with the APG model and water rims caused the increase of the oil displacement factor to 0.734 and

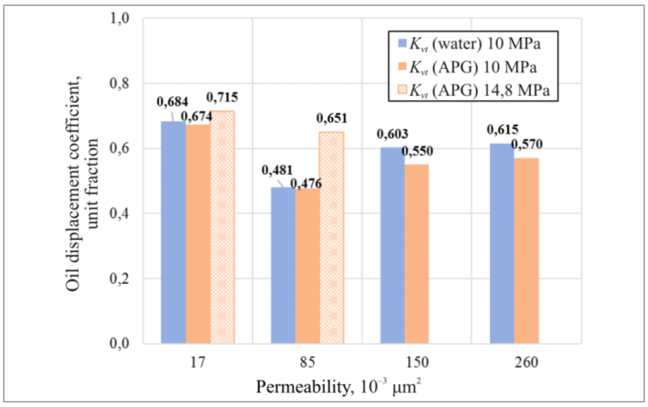

Fig. 4. Comparison of factors of oil displacement with water and gas (APG) under different core model permeability values

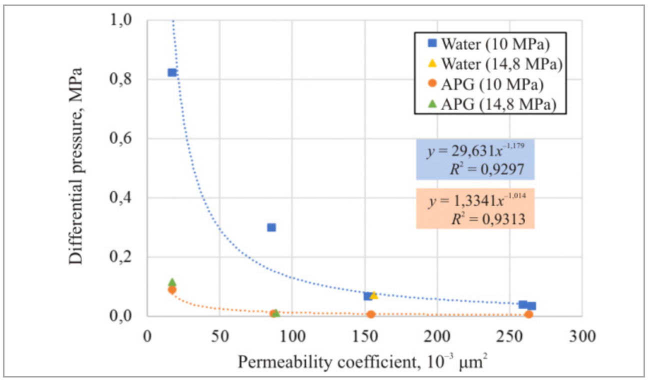

Fig. 5. Dependence of the maximum pressure difference on the gas permeability of the reservoir models

0.724 unit fractions, or by 0.142 and 0.141 unit fractions, respectively. The increase of the oil displacement factor after the gas and water rim injection is caused by the smoothening the oil displacement front and increase of the reservoir model coverage factor by the displacement process.

Fig. 7 presents the comparison of the factors of oil displacement with water, APG model and water followed by APG model and water rim injection. The experiments were carried out on the reservoir models with the equal gas permeability values. In the basic oil displacement variant (displacement with water), the displacement factor constituted 0.615 unit fractures. At the displacement of oil with the APG model, the achieved K_{displ} happened to be lower, equalling to 0.570 unit fractures. Compared to the listed variants, the variant of oil displacement with water followed by oil displacement with APG and water rims ("Water + APG") showed a significant growth of the oil displacement factor. Compared with the basic variant ("Water"), the oil displacement factor increased by 0.11 unit fractions (11.0 %). Compared to the oil displacement with the APG model, the increment constituted 0.154 unit fractions (15.4 %).

Oil Recovery with Cyclic Gas Injection with the Huff'n'Puff Method

The results of the experiments on the cyclic oil recovery in the reservoir models with the residual and initial oil saturation are presented in Fig. 8 that shows the trends of the accumulated displacement factor and the oil displacement factor increment after the displacement of oil with water and after five APG injection cycles with the Huff'n'Puff method (H'n'P).

As we can see from Fig. 8, *a*, after the displacement of oil with water in five APG injection cycles, the final oil displacement factor increased by 0.061 unit fractions (by 6.1 %) – from 0.684 to 0.745 unit fractions. In five cycles, the amount of APG injected into the reservoir model corresponded to 0.345 V_{pore} of the reservoir model. At that,

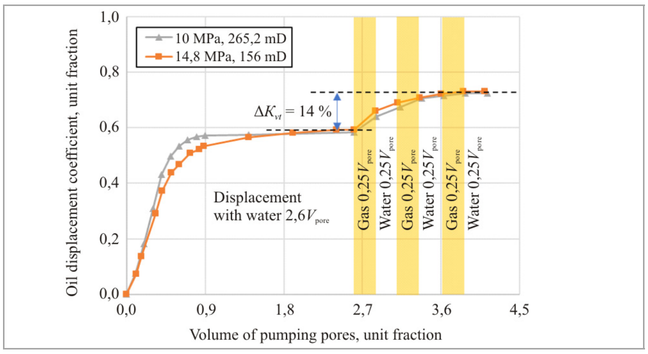

Fig. 6. Dynamics of the factors of oil displacement with water and gas (APG) rim injection at different pore pressure values

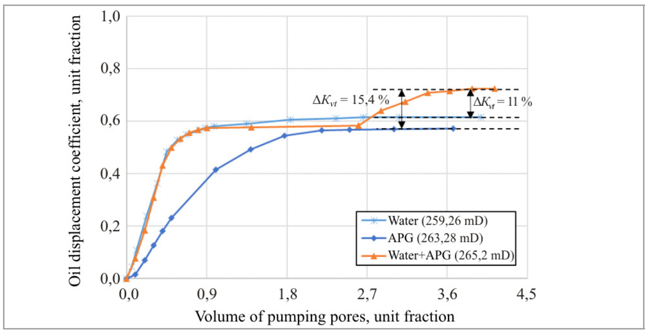

Fig. 7. Dynamics of the factors of oil displacement with water and gas (APG) rim injection at different pore pressure values

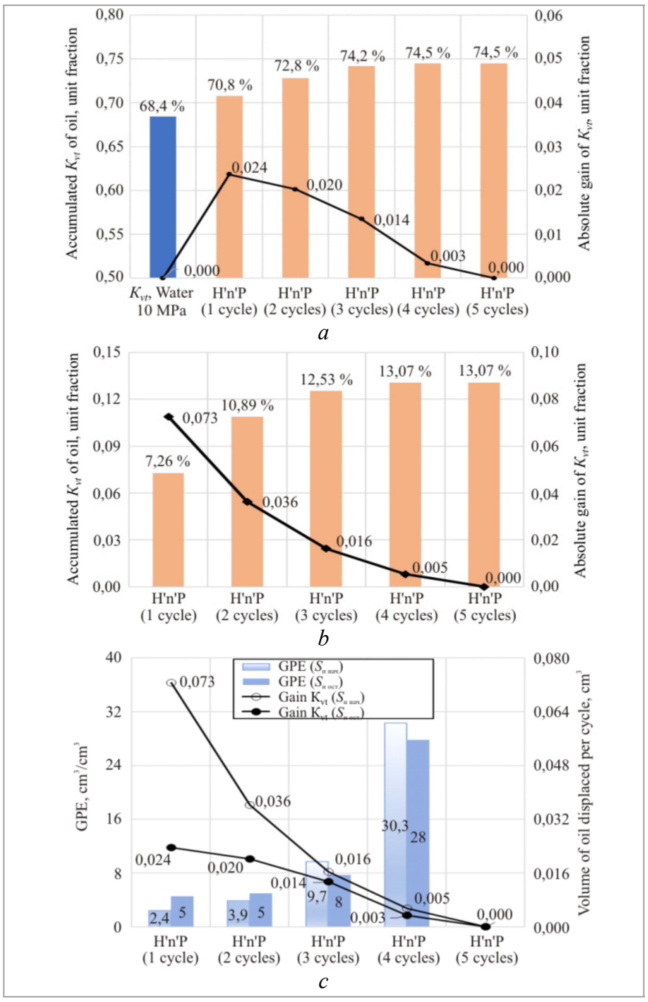

Fig. 8. Results of the experiment on oil recovery with the cyclic APG model injection into the reservoir model after: *a* displacement of oil with water; *b* with initial oil saturation; *c* with initial and residual oil saturation

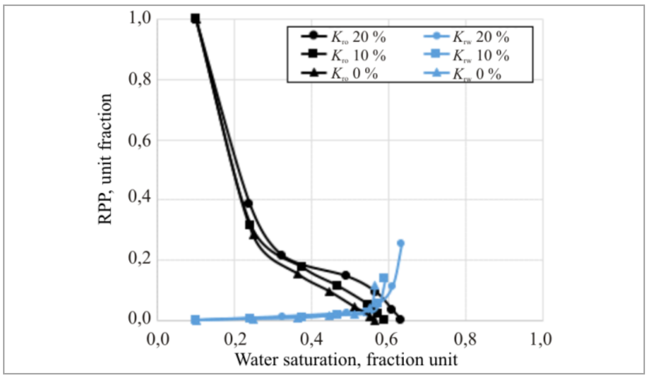

Fig. 9. Relative phase permeability curves in the "oil + APG–water" system for different concentrations of APG model in the oil model of the Tolumskoye field

the greatest increment of the oil displacement factor was achieved after the first H'n'P cycle – 0.024 unit fractions (2.4 %). Then, from one cycle to another, the increment of the oil displacement factor was gradually decreasing, reaching zero at the fifth oil injection cycle. Looking at the experiment results, we may remark that the most efficient cycles are the three first APG injection cycles that make it possible to additionally recover 6 % more oil from the reservoir model.

The results of the experiment on modelling the oil recovery with the cyclic APG model injection into the reservoir core model with the initial oil saturation are presented in Fig. 8, *b*.

We see that the maximum oil displacement increment is also achieved in the first APG injection cycle, constituting 0.073 fraction units (7.3 %). Then, with each cycle, the displacement factor increment value would decrease, reaching 0 after the fifth cycle. After which, the cyclic APG injection was terminated. In total, during the five cycles 22.5 cm³ APG, or 0.562 V_{pore} of the complex reservoir model was injected, and 0.131 unit fractions (13.07 %) of the initial oil content of the reservoir model was recovered.

The efficiency of the cyclic APG model injection into the reservoir models with different oil saturation values was assessed by means of comparison values of the oil recovery factors of every cycle and gas-oil ratio (volume of gas required for the displacement of one unit of the oil volume). As in the fifth cycle the volume of oil recovered in both experiments equals to 0, then the gas-oil ratio value was not calculated. Four cycles were subject to comparison. The comparison of the oil recovery factors and the gas-oil ratio values by cycles for the cyclic APG injection for the reservoir models with the initial and residual oil saturation is presented in Fig. 8, *c*.

For the cyclic APG injection into the reservoir model with $S_{\text{oil initial}}$, in the first cycle the amount of oil recovered is almost three times more compared to the first cycle in the reservoir model with $S_{\text{oil residual}}$. At that, the gas-oil ratio value in the first cycle of the model with $S_{\text{oil initial}}$ is almost twice lower (for the recovery of 1 cm³ of oil required 2.4 cm³ of gas) compared to the same cycle carried out on the model with $S_{\text{oil residual}}$ (4.6 cm³ of gas per 1 cm³ of recovered oil). In the second cycle, the cyclic injection efficiency (gas-oil ratio value) and the K_{displ} in the model with $S_{\text{oil initial}}$ was also higher compared to the cyclic injection in the model with $S_{\text{oil residual}}$. Then, in every next cycle, the oil recovery increment was lowering in both experiments, but in the experiment on the model with $S_{\text{oil initial}}$, the oil recovery increment was falling faster than in the model with $S_{\text{oil residual}}$. The third and the fourth APG injection cycles showed almost the same results in both cases. In the model with $S_{\text{oil initial}}$, the increment of K_{displ} turned out to be higher to a certain extent, but the greatest displacement effect was observed in the experiment on the model with $S_{\text{oil residual}}$.

Determination of the Relative Phase Permeability Values

The results of the relative phase permeability value determination in the "oil + APG–water" system in different concentrations of the APG model in the re-combined oil model under the pore pressure 14.8 MPa and formation temperature 91 °C are presented in Fig. 9.

With the increase of the APG concentration in the recombined model of the Tolumskoye field oil to 20 %, we notice that the end points of the relative phase permeability for water and oil shift to the right. We also observe an increase in the relative phase permeability of the oil base throughout the core model water saturation change diapason in the two-phase filtration.

Conclusion

The completed filtration tests yield the following conclusions:

1. Under otherwise equal conditions, oil displacement with water is to a certain extent more efficient compared with the oil displacement with APG, which is related to the more advantageous ratio between the oil and water viscosities.

2. Much lower pressure differences that occur in the oil displacement with APG in the laboratory conditions prove the potential possibility of involving new reservoir zones into the development provided that the APG injection is applied.

3. The displacement of oil with the APG model under the pore pressure equal to MPP (14.8 MPa) causes a significant rise in the oil displacement factor, which means the effect of the miscible oil displacement with the associated petroleum gas.

4. The alternate injection of APG and water rims after the displacement of oil with water causes the increase in the oil recovery factor by 11-14% compared with the oil displacement only with APG or water, which is caused by smoothening of the displacement front as the water and gas rims are injected.

5. In the experimental conditions, the cyclic APG model injection after the stage of oil displacement with water makes it possible to increase the oil recovery factor by 6.1%. Cyclic APG model injection in the initial oil saturation conditions allow to recover twice more oil – 13.07%.

6. Under otherwise equal conditions, the increase of the APG concentration in oil causes the growth of the relative phase permeability values for oil and water and the two-phase filtration zone (shifting the end points to the right).

References

1. Baikov N.M. Opyt povysheniia nefteotdachi na mestorozhdeniiakh SShA putem zakachki SO_2 [Experience in enhanced oil recovery at US fields by injecting CO_2]. *Neftianoe khoziaistvo*, 2012, no. 11, pp. 141-143.
2. Ramochnaia konventsiia ob izmenenii klimata. Parizhskoe soglashenie [Framework convention on climate change. Paris Agreement], available at: https://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf (accessed 20 June 2021).
3. Otchet ob ustoichivom razvitii gruppy "LUKOIL" [LUKOIL Group Sustainability Report], 2020, pp. 25-26, 56-57.
4. Osnovnye pokazateli dobychi prirodnogo i poputnogo neftianogo gaza Rossiiskoi Federatsii [Key indicators of natural and associated petroleum gas production in the Russian Federation], available at: https://minenergo.gov.ru/node/1215 (accessed 20 June 2021).
5. Eder L.V., Provornaia I.V., Filimonova I.V. Dobycha i utilizatsiia poputnogo neftianogo gaza kak napravlenie kompleksnogo osvoeniia nedr: rol' gosudarstva i biznesa, tekhnologii i ekologicheskikh ogranichenii [Production and utilization of associated petroleum gas as an integrated subsoil development: the role of the state and business, technologies and environmental restrictions]. *Burenie i neft'*, 2016, no. 10, pp. 8-15.
6. Bocharov D.D. Kompleksnaia otsenka innovatsionnykh proektov ratsional'nogo ispol'zovaniia poputnogo neftianogo gaza [Comprehensive assessments of innovative projects for the rational use of the associated petroleum gas]. Abstract of Ph. D. thesis. Moscow: NIU Vysshaia shkola ekonomiki, 2011, 27 p.
7. Grushevenko E. et al. Dekarbonizatsiia neftegazovoi otrasli: mezhdunarodnyi opyt i prioritety Rossii [Decarbonization of the oil and gas industry: global experience and Russia's priorities]. Moscow: Skolkovo, 2021.
8. Mezhdunarodnye podkhody k uglerodnomu tsenoobrazovaniiu [International approaches to carbon pricing]. Moscow: Departament mnogostoronnego ekonomicheskogo sotrudnichestva Minekonomrazvitiia Rossii, 2021.
9. Braginskii O.B. Utilizatsiia poputnogo neftianogo gaza - faktor ratsional'nogo ispol'zovaniia uglevodorodnogo syr'ia [Utilization of associated petroleum gas as a factor in the rational use of hydrocarbon raw materials]. *Ekonomicheskii analiz: teoriia i praktika*, 2014, no. 23 (374), available at: https://cyberleninka.ru/article/n/utilizatsiya-poputnogo-neftyanogo-gaza-faktor-ratsionalnogo-ispolzovaniya-uglevodorodnogo-syrya (accessed 20 June 2021).
10. Knizhnikov A.Iu., Il'in A.M. Vsemirnyi fond dikoi prirody (WWF). Problemy i perspektivy ispol'zovaniia poputnogo neftianogo gaza v Rossii [World Wildlife Fund (WWF). Problems and Prospects of Associated Petroleum Gas Utilization in Russia]. Moscow, 2017.
11. 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, vol. 19, no. 4, pp. 373-387. DOI: 10.15593/2224-9923/2019.4.6
12. Moroziuk O.A. et al. 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
13. Lake L.W. Enhanced Oil Recovery Fundamentals. Society of Petroleum Engineers, 1985. DOI: 10.30713/2413-5011-2019-6(330)-51-56
14. Moroziuk O.A. et al. Otsenka vliianiia poputnogo neftianogo gaza s vysokim soderzhaniem dioksida ugleroda na rezhim vytesneniia nefti pri razrabotke Tolumskogo mestorozhdeniia [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]. *Vestnik Permskogo natsional'nogo issledovatel'skogo politekhnicheskogo universiteta. Geologiia, neftegazovoe i gornoe delo*, 2021, vol. 21, no. 1. DOI: 10.15593/2712-8008/2021.1.7
15. Dopolnenie k tekhnologicheskomu proektu razrabotki Tolumskogo neftianogo mestorozhdeniia [Supplement to the technological project for the development of the Tolum oil field]. 2018.
16. GOST 31371.7. Gaz prirodnyi. Opredelenie sostava metodov gazovoi khromatografii s otsenkoi neopredelennosti. Chast' 7. Metodika izmerenii moliarnoi doli komponentov [GOST 31371.7. Natural gas. Finding the composition of gas chromatography methods with an uncertainty estimate. Part 7. Procedure for measuring the molar fraction of components]. Moscow, 2007.
17. Alekseev A. Pod naporom. Tekhnologiia obratnoi zakachki gaza v neftianoi plast [Under pressure. Gas re-injection technology into oil reservoirs]. *Sibirskaia neft'*, 2018, no. 152, available at: https://www.gazprom-neft.ru/press-center/sibneft-online/archive/2018-june/ (accessed 17 June 2021).
18. Optimizatsiia obratnoi zakachki gaza s tsel'iu uvelicheniia nefteotdachi na neftegazokondensatnom mestorozhdenii [Optimization of gas re-injection in order to increase oil recovery in an oil and gas condensate field]. *Proneft': nauchno-tekhnicheskii zhurnal "Gazprom neft'"*, 2016, no. 2, available at: https://ntc.gazprom-neft.ru/research-and-development/proneft /777/13454/ (accessed 17 June 2021).
19. Stoisits R.F. et al. Simultaneous water and gas injection pilot at the Kuparuk River field, surface line impact. *SPE. Annual Technical Conference and Exhibition*. OnePetro, 1995. SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 1995. DOI: 10.2118/30645-MS
20. Afzali S., Rezaei N., Zendehboudi S. A comprehensive review on enhanced oil recovery by water alternating gas (WAG) injection. *Fuel*, 2018, vol. 227, pp. 218-246. DOI: 10.1016/j.fuel.2018.04.015
21. Christensen J.R., Stenby E.H., Skauge A. Review of WAG field experience. *SPE. Reservoir Evaluation & Engineering*, 2001, vol. 4, no. 2, pp. 97-106. DOI: 10.2118/71203-PA
22. Savitsky N. Results of experimental studies and field tests of the technology of oil displacement with fine water-gas mixture. *SPE. Russian Oil and Gas Conference and Exhibition*, 2010. DOI: 10.2118/138067-ms
23. Leibin E.L., Sharifullin F.A., Zanichkovskii F.M., Maksutov R.A. Sposob razrabotki neftianoi zalezhi na pozdnei stadii putem vodogazo-gidrodinamicheskogo vozdeistviia pri periodicheskom izmenenii dispersnosti gazovoi fazy [A method of developing an oil reservoir at a late stage by means of water-gas-hydrodynamic action with a periodic change in the dispersion of the gas phase]. Patent Rossiiskaia Federatsiia no. 2318997 (2008)
24. Mirzadzhanzade A.Kh., Ametov I.M., Bogopol'skii A.O. Sposob razrabotki neftianoi zalezhi]. Avtorskoe svidetel'stvo [Oil reservoir development method]. Avtorskoe svidetel'stvo no. 1822219 (1990).
25. Mirzadzhanzade A.Kh., Khasanov M.M., Bakhtizin R.N. Modelirovanie protsessov neftegazodobychi. Nelineinost', neravnovesnost', neopredelennost' [Modeling of oil and gas production processes. Nonlinearity, disequilibrium, uncertainty]. Moscow, Izhevsk: Institut komp'iuternykh issledovanii, 2004, 368 p.
26. Zatsepin V.V. Tekhnologicheskie osnovy vodogazovogo vozdeistviia na plasty s trudnoizvlekaemymi zapasami nefti v nizkopronitsaemykh kollektorakh [Technological foundations of water-gas stimulation of reservoirs with hard-to-recover oil reserves in low-permeability reservoirs]. Ph. D. thesis. Kazan', 2017.
27. Eronin N.M. Slovo o groznenskikh neftianikakh [A word about Grozny oil workers]. *Neftianoe khoziaistvo*, 2001, no. 7.
28. Zemtsov Iu.V. et al. Rezul'taty zakachek melkodispersnoi vodogazovoi smesi dlia uvelicheniia nefteotdachi ob"ekta BV 8 Samotlorskogo mestorozhdeniia [Results of injection of a finely dispersed water-gas mixture to enhance oil recovery from the BV 8 facility of the Samotlor field]. *Geologiia, geofizika i razrabotka neftianykh i gazovykh mestorozhdenii*, 2013, no. 10, pp. 49-55.
29. Van'kov A., Nurgaliev R. Skhema zakachki vodogazovoi smesi v plast s utilizatsiei poputnogo neftianogo gaza [Scheme of injection of a water-gas mixture into a reservoir with utilization of associated petroleum gas]. *Tekhnologii toplivno-energeticheskogo kompleksa*, 2007, no. 5, pp. 63-69.
30. Stright D.H., Aziz K. Carbon dioxide injection into bottom-water, undersaturated viscous oil reservoirs. *Journal of Petroleum Technology*, 1977, vol. 29, no. 10, pp. 1248-1258. DOI: 10.2118/6116-PA
31. Patton J.T., Coats K.H., Spence K. Carbon Dioxide well stimulation: Part 1-A parametric study. *Journal of Petroleum Technology*, 1982, vol. 34, no. 08, P. 1798-1804. DOI: 10.2118/9228-PA
32. Patton J.T. et al. Authors' reply to discussion of carbon dioxide well stimulation: Part 2-design of Aminoil's North Bolsa Strip project. *J. Pet. Technol. (United States)*, 1983, vol. 35, no. 7. DOI: 10.2118/8897-PA
33. Monger T.G., Coma J.M. A laboratory and field evaluation of the CO_2 huff'n'puff process for light-oil recovery. *SPE reservoir engineering*, 1988, vol. 3, no. 04, pp. 1168-1176. DOI: 10.2118/15501-PA
34. Ma J. et al. Enhanced light oil recovery from tight formations through CO_2 huff 'n'puff processes. *Fuel*, 2015, vol. 154, pp. 35-44. DOI: 10.1016/j.fuel.2015.03.029
35. Haines H.K., Monger T.G. A laboratory study of natural gas huffn'puff. *CIM/SPE International Technical Meeting*. OnePetro, 1990. DOI: 10.2118/21576-MS
36. Sahin S. et al. A quarter century of progress in the application of CO_2 immiscible EOR project in Bati Raman heavy oil field in Turkey. *SPE Heavy Oil Conference Canada*, OnePetro, 2012. DOI: 10.2118/157865-MS
37. Olenick S. et al. Cyclic CO_2 injection for heavy-oil recovery in Halfmoon field: laboratory evaluation and pilot performance. *SPE Annual Technical Conference and Exhibition*. OnePetro, 1992. DOI: 10.2118/24645-MS
38. Issever K., Pamir A.N., Tirek A. Performance of a heavy-oil field under CO_2 injection, Bati Raman, Turkey. *SPE Reservoir Engineering*, 1993, vol. 8, no. 04, pp. 256-260. DOI: 10.2118/20883-PA
39. Torabi F. et al. Comparative evaluation of immiscible, near miscible and miscible CO2 huff-n-puff to enhance oil recovery from a single matrix-fracture system (experimental and simulation studies). *Fuel*, 2012, vol. 93, pp. 443-453. DOI: 10.1016/j.fuel.2011.08.037
40. RITEK vpervye v Rossii primenil tekhnologiiu Huff & Puff. Novost' ot 16.10.2017 [RITEK was the first in Russia to use Huff&Puff technology. News from October 16, 2017], available at: http://ritek.lukoil.ru/ru/News/News?rid=164926 (accessed October 30, 2017).
41. Darishchev V.V. et al. Realizatsiia tekhnologii zakachki uglekislogo gaza v dobyvaiushchie skvazhiny [CO_2 huff & puff injection into production wells]. *Neft'. Gaz. Novatsii*, 2020, no. 7, pp. 33-38.
42. Kalinin S.A., Moroziuk O.A. Laboratornye issledovaniia karbonatnykh kollektorov mestorozhdenii vysokoviazkoi nefti s ispol'zovaniem dioksida ugleroda [Laboratory studies of carbonate reservoirs of high-viscosity oil fields using carbon dioxide]. *Vestnik Permskogo natsional'nogo issledovatel'skogo politekhnicheskogo universiteta. Geologiia, neftegazovoe i gornoe delo*, 2020, vol. 20, no. 4. DOI: 10.15593/2712-8008/2020.4.6
43. 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.
44. OST 39-195-86. Neft'. Metod opredeleniia koeffitsienta vytesneniia nefti vodoi v laboratornykh usloviiakh [OST 39-195-86. Oil. Method for determining the coefficient of oil displacement by water in laboratory conditions]. Moscow, 1986.
45. Todd M.R., Longstaff W.J. The Development, Testing, and Application of a Numerical Simulator for Predicting Miscible Flood Performance. *Journal of Petroleum Technology*, 1972, vol. 24 (07), pp. 874-882. DOI: 10.2118/3484-pa
46. OST 39-235-89. Neft'. Metod opredeleniia fazovykh pronitsaemostei v laboratornykh usloviiakh pri sovmestnoi statsionarnoi fil'tratsii [OST 39-235-89. Oil. Method for determination of phase permeabilities in laboratory conditions with joint stationary filtration]. Moscow, 1989.

Библиографический список

1. Байков Н.М. Опыт повышения нефтеотдачи на месторождениях США путем закачки CO_2 // Нефтяное хозяйство. – 2012. – № 11. – С. 141–143
2. Рамочная конвенция об изменении климата. Парижское соглашение [Электронный ресурс]. – URL: https://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf (дата обращения: 20.06.2021).
3. Отчет об устойчивом развитии группы «ЛУКОЙЛ». – 2020. – С. 25–26, 56–57.
4. Основные показатели добычи природного и попутного нефтяного газа Российской Федерации [Электронный ресурс]. – URL: https://minenergo.gov.ru/node/1215 (дата обращения: 20.06.2021).
5. Эдер Л.В., Проворная И.В., Филимонова И.В. Добыча и утилизация попутного нефтяного газа как направление комплексного освоения недр: роль государства и бизнеса, технологий и экологических ограничений // Бурение и нефть. – 2016. – № 10. – С. 8–15.
6. Бочаров Д.Д. Комплексная оценка инновационных проектов рационального использования попутного нефтяного газа: автореф. дис. … канд. техн. наук. – М.: НИУ ВШЭ, 2011. – 27 с.
7. Декарбонизация нефтегазовой отрасли: международный опыт и приоритеты России / Е. Грушевенко [и др.]. – М.: Сколково, 2021.
8. Международные подходы к углеродному ценообразованию / Департамент многостороннего экономического сотрудничества Минэкономразвития России. – М., 2021.
9. Брагинский О.Б. Утилизация попутного нефтяного газа – фактор рационального использования углеводородного сырья [Электронный ресурс] // Экономический анализ: теория и практика. – 2014. – № 23 (374). – URL: https://cyberleninka.ru/article/n/utilizatsiya-poputnogo-neftyanogo-gaza-faktor-ratsionalnogo-ispolzovaniya-uglevodorodnogo-syrya (дата обращения: 20.06.2021).
10. Книжников А.Ю., Ильин А.М. Всемирный фонд дикой природы (WWF). Проблемы и перспективы использования попутного нефтяного газа в России. – М., 2017.
11. 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. – Т. 19, № 4. – С. 373–387. DOI: 10.15593/2224-9923/2019.4.6
12. Экспериментальные исследования вытеснения высоковязкой нефти диоксидом углерода из карбонатных пород / О.А. Морозюк [и др.] // Геология, геофизика и разработка нефтяных и газовых месторождений. – 2019. – № 6. – С. 51–56. DOI: 10.30713/2413-5011-2019-6(330)-51-56
13. Lake L.W. Enhanced Oil Recovery Fundamentals. – Society of Petroleum Engineers, 1985. DOI: 10.30713/2413-5011-2019-6(330)-51-56
14. Оценка влияния попутного нефтяного газа с высоким содержанием диоксида углерода на режим вытеснения нефти при разработке Толумского месторождения / О.А. Морозюк [и др.] // Вестник Пермского национального исследовательского политехнического университета. Геология, нефтегазовое и горное дело. – 2021. – Т. 21, №. 1. DOI: 10.15593/2712-8008/2021.1.7
15. Дополнение к технологическому проекту разработки Толумского нефтяного месторождения. – 2018.
16. ГОСТ 31371.7. Газ природный. Определение состава методов газовой хроматографии с оценкой неопределенности. Часть 7: Методика измерений молярной доли компонентов. – М., 2007.
17. Алексеев А. Под напором. Технология обратной закачки газа в нефтяной пласт [Электронный ресурс] // Сибирская нефть. – 2018. – № 152. – URL: https://www.gazprom-neft.ru/press-center/sibneft-online/archive/2018-june/ (дата обращения: 17.06.2021).
18. Оптимизация обратной закачки газа с целью увеличения нефтеотдачи на нефтегазоконденсатном месторождении [Электронный ресурс] // Pronефть: научно-технический журнал «Газпром нефть». – 2016. – № 2. – URL: https://ntc.gazprom-neft.ru/research-and-development/proneft /777/13454/ (дата обращения: 17.06.2021).
19. Simultaneous water and gas injection pilot at the Kuparuk River field, surface line impact / R.F. Stoisits [et al.] // SPE. Annual Technical Conference and Exhibition. – OnePetro, 1995. DOI: 10.2118/30645-MS
20. 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.fuel.2018.04.015
21. Christensen J.R., Stenby E.H., Skauge A. Review of WAG field experience // SPE. Reservoir Evaluation & Engineering. – 2001. – Vol. 4, № 2. – P. 97–106. DOI: 10.2118/71203-PA
22. Savitsky N. Results of experimental studies and field tests of the technology of oil displacement with fine water-gas mixture // SPE. Russian Oil and Gas Conference and Exhibition. – 2010. DOI: 10.2118/138067-ms.
23. Пат. 2318997, Российская Федерация. Способ разработки нефтяной залежи на поздней стадии путем водогазо-гидродинамического воздействия при периодическом изменении дисперсности газовой фазы / Лейбин Э.Л., Шарифуллин Ф.А., Заничковский Ф.М., Максутов Р.А.
24. Способ разработки нефтяной залежи: а. с. 1822219, СССР / Мирзаджанзаде А.Х., Аметов И.М., Богопольский А.О.
25. Мирзаджанзаде А.Х., Хасанов М.М., Бахтизин Р.Н. Моделирование процессов нефтегазодобычи. Нелинейность, неравновесность, неопределенность. – М. – Ижевск: Институт компьютерных исследований, 2004. – 368 с.
26. Зацепин В.В. Технологические основы водогазового воздействия на пласты с трудноизвлекаемыми запасами нефти в низкопроницаемых коллекторах: дис. … канд. техн. наук. – Казань, 2017.
27. Еронин Н.М. Слово о грозненских нефтяниках // Нефтяное хозяйство. – 2001. – № 7.
28. Результаты закачек мелкодисперсной водогазовой смеси для увеличения нефтеотдачи объекта БВ 8 Самотлорского месторождения / Ю.В. Земцов [и др.] // Геология, геофизика и разработка нефтяных и газовых месторождений. – 2013. – № 10. – С. 49–55.
29. Ваньков А., Нургалиев Р. Схема закачки водогазовой смеси в пласт с утилизацией попутного нефтяного газа // Технологии топливно-энергетического комплекса. – 2007. – № 5. – С. 63–69.
30. Stright D.H., Aziz K. Carbon dioxide injection into bottom-water, undersaturated viscous oil reservoirs // Journal of Petroleum Technology. – 1977. – Vol. 29, № 10. – P. 1248–1258. DOI: 10.2118/6116-PA
31. Patton J.T., Coats K.H., Spence K. Carbon Dioxide well stimulation: Part 1-A parametric study // Journal of Petroleum Technology. – 1982. – Vol. 34, № 08. – P. 1798–1804. DOI: 10.2118/9228-PA
32. Authors' reply to discussion of carbon dioxide well stimulation: Part 2-design of Aminoil's North Bolsa Strip project / J.T. Patton [et al.] // J. Pet. Technol. (United States). – 1983. – Vol. 35, № 7. DOI: 10.2118/8897-PA
33. Monger T.G., Coma J.M. A laboratory and field evaluation of the CO_2 huff'n'puff process for light-oil recovery // SPE reservoir engineering. – 1988. – Vol. 3, № 04. – P. 1168–1176. DOI: 10.2118/15501-PA
34. Enhanced light oil recovery from tight formations through CO_2 huff 'n'puff processes / J. Ma [et al.] // Fuel. – 2015. – Vol. 154. – P. 35-44. DOI: 10.1016/j.fuel.2015.03.029
35. Haines H.K., Monger T.G. A laboratory study of natural gas huffn'puff // CIM/SPE International Technical Meeting. – OnePetro, 1990. DOI: 10.2118/21576-MS
36. A quarter century of progress in the application of CO_2 immiscible EOR project in Bati Raman heavy oil field in Turkey / S. Sahin [et al.] // SPE Heavy Oil Conference Canada. – OnePetro, 2012. DOI: 10.2118/157865-MS
37. Cyclic CO_2 injection for heavy-oil recovery in Halfmoon field: laboratory evaluation and pilot performance / S. Olenick [et al.] // SPE Annual Technical Conference and Exhibition. – OnePetro, 1992. DOI: 10.2118/24645-MS
38. Issever K., Pamir A.N., Tirek A. Performance of a heavy-oil field under CO_2 injection, Bati Raman, Turkey // SPE Reservoir Engineering. – 1993. – Vol. 8, № 04. – P. 256–260. DOI: 10.2118/20883-PA
39. Comparative evaluation of immiscible, near miscible and miscible CO_2 huff-n-puff to enhance oil recovery from a single matrix–fracture system (experimental and simulation studies) / F. Torabi [et al.] // Fuel. – 2012. – Vol. 93. – P. 443–453. DOI: 10.1016/j.fuel.2011.08.037
40. РИТЭК впервые в России применил технологию Huff & Puff. Новость от 16.10.2017 [Электронный ресурс]. – URL: http://ritek.lukoil.ru/ru/News/News?rid=164926 (дата обращения: 30.10.2017).
41. Реализация технологии закачки углекислого газа в добывающие скважины / В.В. Дарищев [и др.] // Нефть. Газ. Новации. – 2020. – № 7. – С. 33–38.
42. Калинин С.А., Морозюк О.А. Лабораторные исследования карбонатных коллекторов месторождений высоковязкой нефти с использованием диоксида углерода // Вестник Пермского национального исследовательского политехнического университета. Геология, нефтегазовое и горное дело. – 2020. – Т. 20, № 4. DOI: 10.15593/2712-8008/2020.4.6
43. ОСТ 153-39.2-048-2003. Нефть. Типовые исследования пластовых флюидов и сепарированных нефтей. – М., 2003.
44. ОСТ 39-195-86. Нефть. Метод определения коэффициента вытеснения нефти водой в лабораторных условиях. – М., 1986.
45. Todd M.R., Longstaff W.J. The Development, Testing, and Application Of a Numerical Simulator for Predicting Miscible Flood Performance // Journal of Petroleum Technology. – 1972. – Vol. 24 (07). – P. 874–882. DOI:10.2118/3484-pa.
46. ОСТ 39-235-89. Нефть. Метод определения фазовых проницаемостей в лабораторных условиях при совместной стационарной фильтрации. – М., 1989.