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Experimental studies of Physico-hydrodynamic parameters of Carbon Dioxide Application

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Abstract

The article presents new results of laboratory studies, along with a summary of previously obtained ones. An analysis of the development of reserves in the experimental area was carried out with recommendations for improving the efficiency of its oil recovery processes in the amount of 10-30% of the pore volume of the experimental area. New conditions for injection with a limited supply of carbon dioxide are considered. The results of oil recovery modeling, using CO_2 and water rims, are presented. The increase in oil recovery for reservoirs D_1 and D_2 was determined, and a forecast was made for the value of additional oil production per ton of carbon dioxide.

Keywords: *Core, Efficiency increase, Oil displacement, Injection, Carbon dioxide, Oil recovery.*

1. Introduction

This work was carried out in accordance with the research schedule and is an addition to the theoretical study of the injection of carbon dioxide into the productive strata of depleted oil fields. The paper clarifies the geological characteristics of the experimental area and sets out main issues, the solution of which depends on the volume of CO_2 supply.

A preliminary assessment of the effectiveness of the use of CO_2 in one- production well is given. The results of testing the technology for washing the sediment of asphalt-resinous substances in injection wells are presented.

Recommendations are given for the development and restoration of injection wells. The results obtained and these recommendations can be used for CO_2 injection (Andreev et al 2023, ChizhovA et al 2021, Rabaev et al. 2021).

2. Materials and methods

The substantiation of the design provisions of the pilot works involves laboratory studies to determine the oil displacement coefficients for water, carbonated water, carbon dioxide, and the effect of CO_2 on the physical properties of oil, water, and host rocks.

To test the conditions of the experimental site of the oil field, a set of laboratory studies has been carried out to study the solubility of CO_2 in oil, the effect of carbon dioxide on the composition and gas factor of oil, its distribution over heterogeneous layers during filtration.

For the preparation of porous media, cores of Devonian deposits were used, taken in well Nos. as Devonian productive objects. Layer D_1 is represented by 47 samples of core material, layer D_2-57 samples. Oil saturation was determined from core samples from wells Nos. 1070 and 1173.

The parameters of the core material samples are shown in Table 1. A comparison of the weighted average values of the parameters of the samples showed that reservoir D_1 has better reservoir properties than reservoir D_2. The filtration properties of the D_1 formation samples are 1.8 times higher, the porosity is 8.8% higher, and the carbonate and clay contents are 1.3 and 1.4 times lower respectively (Figure 1).

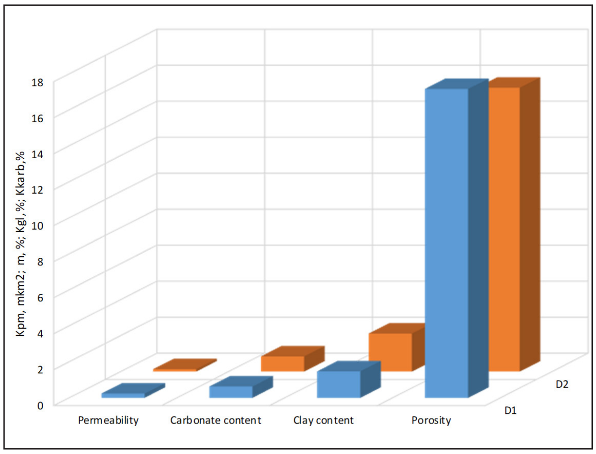

Figure 1. Thickness-weighted average values of the main parameters of sandstone samples

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Table 1. Thickness-weighted parameters of the core material of the polygon object

Wells	Definitions	Parameters				
	Layer	Permeability, ×10^{-12} m^2	Porosity, %	Carbonate content, %	Clay content, %	Oil saturation, %
733	Quantity	7	7	7	7	-
	D_1	0,144	15,7	1,24	1,87	-
880	Quantity	2	2	2	2	-
	D_1	0,334	18,4	0,8	1,6	-
	Quantity	28	28	28	28	-
	D_2	0,131	16,3	1	2,3	-
1070	Quantity	25	25	25	25	25
	D_2	0,149	15,5	0,6	2	36,9
1173	Quantity	26	29	28	29	28
	D_1	0,238	17,2	0,37	1,3	36,4
	Quantity	4	4	4	4	3
	D_2	0,05	14,2	1,64	1,7	29

Table 2. Average values of the parameters of the sandstone samples of the deposit before and after exposure to carbon dioxide

Permeability interval, ×10^{-12} m^2	Initial values				After exposure to CO_2			
	Kpr, ×10^{-12} m^2	m, %	Kkarb, %	Kgl, %	Kpr, ×10^{-12} m^2	m, %	Kkarb, %	Kgl, %
0.01-0.05	0	15.67	1.3	2.38	0.051	15.92	1.23	1.05
0.05-0.10	0.1	15.75	0.67	1.8	0.104	16.16	0.62	1.18
0.10-0.20	0.1	16.51	0.91	2.02	0.158	16.73	0.67	0.63
0.20-0.30	0.2	17	0.73	2.07	0.256	17.28	0.58	1.12
0.30-0.40	0.4	17.63	0.59	1.85	0.393	18.1	0.51	1.03
0.40-0.50	0.5	17.65	0.67	1.62	0.528	18	0.51	1.29
0.50-0.60	0.5	19.1	0.3	1.07	0.577	19.4	-	-
0.80-1.00	0.9	20.9	0.56	0.73	1.087	21.4	0.4	0.62

Notes: Kpr – permeability; m – porosity; Kkarb - carbonate content; Kgl - clay content.

Under the experimental conditions (pressure 11 MPa, temperature 313 °K), the oil had a viscosity of 7.86 mPa×s, a density of 0.848 g/cm^3, a viscosity of water of 0.856 mPa×s, and a density of 1.0614 g/cm^3 (Chizhov et al 2020, Mousa et al 2012, Qahir et al 2014). The solubility of CO_2 in water and oil under reservoir conditions was experimentally determined (Table 3, Figure 2), as well as the change in the gas factor of oil saturated with CO_2 (Table 4, Figure 3).

Table 3. Solubility of CO_2 in injected water

Pressure, Mpa	4	6	8	10	12	14	16	18
CO_2 concentration in water, % by weight	2.3	3.3	3.8	4	4.1	4.2	4.3	4.4

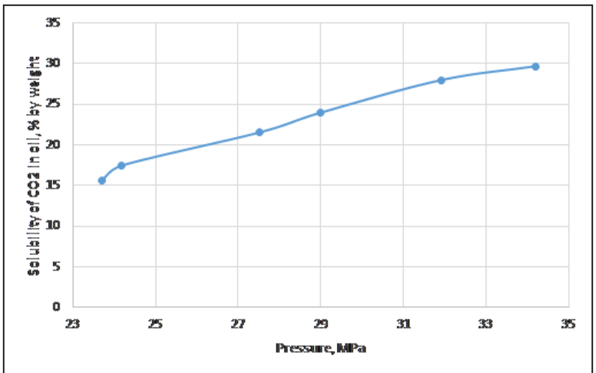

Figure 2. Solubility of carbon dioxide in oil

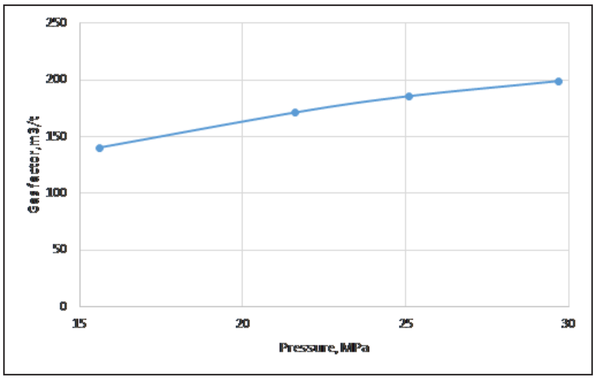

Figure 3. GOR of oil saturated with CO_2

Table 4. Change in GOR of oil saturated with carbon dioxide under reservoir conditions

GOR*, m^3/t/share.unit	37/1	72.40/1.89	91.50/2.38	143.90/3.75
CO_2 concentration in oil, % wt.	0	5	10	20
* Pressure - 18.5 MPa, temperature - 313°K				

Dissolving in oil, carbon dioxide significantly reduces its viscosity and increases saturation pressure. The distribution coefficients of CO_2 between water and oil and oil and the CO_2 phase, were determined under dynamic conditions in free volume at a pressure of 11 MPa and a temperature of 313 °K. The average value of the distribution coefficient between oil and water is 1.83, and it is between oil and CO_2 phase is 4.28.

3. Results and Discussion

The displacement of oil with water, carbonized water, and carbon dioxide was carried out at a pressure of 11 MPa and a temperature of 313 °K. The results of oil displacement by water (Table 5, Figure 4) show that in the permeability range of 0.02-0.05×10^{-12} m^2, the displacement coefficient increases from 0.665 to 0.699, and in the permeability range of 0.05 - 0.25, the oil displacement coefficient by water is 0.697± 0.043.

The results of experiments on oil displacement by carbon dioxide show that the alternating injection of portions of CO_2 and water does not reduce the efficiency of the method.

Table 5. Coefficient of oil displacement by water from core sandstones

Number models	Length of reservoir model, m	Permeability, ×10^{-12} m^2	Porosity,%	Bound water,%	Water flow rate, m/year
1	0.411	0.004	14	10	66
2	0.569	0.023	16.8	10	189
3	0.55	0.025	17.2	9.5	30
4	0.428	0.034	15.2	9.8	106
5	0.408	0.052	16.4	11.1	293
6	0.573	0.054	18.4	8.6	253
7	0.408	0.059	16.3	10.4	294
8	0.402	0.064	16.6	9.2	145
9	0.402	0.069	16.1	10	298
10	0.573	0.108	18.5	9.7	252
11	0.589	0.12	16.4	9.6	282
12	0.429	0.124	16.2	9.2	332
13	0.589	0.142	16.6	9.8	279
14	0.588	0.143	16.9	9.2	265
15	0.583	0.146	17	9.8	322
16	0.42	0.198	18	10	267
17	0.423	0.206	17.8	9.7	270
18	0.421	0.216	18	9.4	270
19	0.423	0.225	17.7	9.6	270
20	0.42	0.227	17.9	9.6	267

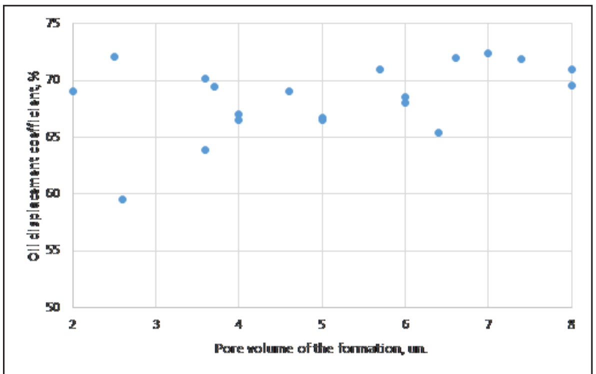

Figure 4. Oil displacement values for different CO2 injection volumes

At the next stage of research, the distribution of carbon dioxide over heterogeneous reservoirs was determined during the filtration process. According to (Chizhov et al 2020, Chizhov et al 2019, Andreev et al 2019), the main technological parameters of CO_2 and water injection were the total volume of the CO_2 slug (Vot) that is 15% Vn, and the ratio of the volumes of injected water and CO_2, (λ) is 3:2. In subsequent experiments, the values Vot and λ, accepted in (Chizhov et al 2020, Chizhov et al 2019), were confirmed. The minimum number of portions (n) into which the CO_2 slug must be divided is also determined in order to prevent premature breakthrough of the reagent into production wells. Experiments to determine the minimum required number of CO_2 portions were carried out on models of non-communicating, heterogeneous reservoirs with a common input and separate withdrawal of fluids. Considering that the change in such parameters as oil saturation, composition, and properties of residual oil cannot be controlled during the studies. All experiments were carried out on water-saturated reservoir models (Table 6).

Table 6. Characterization of reservoir models

Model number	Length, $\times10^{-2}$ m		Permeability, $\times10^{-12}$ m^2		Permeability ratio, units
1	58	54.8	0.144	0.018	7.8
2	52	54.8	0.158	0.026	6
3	54.8	54.8	0.133	0.039	3.41
4*	101.8	54.8	5.001	0.039	128.2

*Note: Model 4 was made for the physical modeling of phase permeabilities, which can be an order of magnitude or greater than the ratio of reservoir permeabilities

On these reservoir models, several series of experiments were carried out at a pressure of 10.0 MPa, a temperature of 299.5 °K and 313 °K, and an average velocity of fluids in the pore space of 201 m/year. The volume of the CO_2 slug was 12 and 16% of the pore volume of the reservoir model samples. Each series consisted of four experiments, during which the injected CO_2 slug was divided into 5, 10, 20, or 40 portions. In each series of experiments, the ratio of the volumes of water and CO_2 were constant. A series of experiments was carried out for at ratios of water and CO_2 equal to 1, 1.5, 2, and 3. Since the reservoir temperature of the polygon is 313 °K and exceeds the critical temperature of CO_2 (304.1 °K), two series of experiments were carried out to determine the degree of influence of the state of aggregation of carbon dioxide on its distribution in heterogeneous reservoirs. The experiments were carried out at temperatures of 299.5 °K and 313 °K. The results of the experiments are shown in Tables 7 and 8.

Table 7. Influence of the state of aggregation of carbon dioxide on the distribution parameters in reservoirs with different permeabilities

Temperature, °K	Number of servings, units				
	1	5	10	20	40
299.5	3.42	3.05	2.77	2.68	2.54
313	3.6	3.22	3.11	2.96	2.76

The distribution parameter (R) is a dimensionless value, which is the ratio of the amount of fluid entering the high-permeability reservoir (Qv) to the amount of fluid entering the low-permeability reservoir (Qn).

Table 8. Distribution parameters of carbon dioxide rims with a size of 12% of the void space of the reservoir at various values of the ratios of CO_2 to water and the number of portions

The ratio of CO_2 to water (λ), units	Number of servings, units			
	5	10	20	40
3	2,24	2,39	1,4	1,24
2	1,53	1,64	1,49	-
1,5	1,61	1,51	1,42	1,37
1	1,63	1,9	1,59	1,59

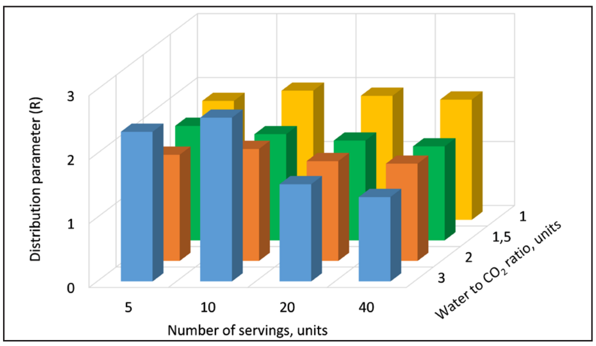

Figure 5. Distribution parameters of carbon dioxide fringes with a size of 16% of the pore space at different values of the ratio of CO_2, water, and the number of servings

Experiments have shown that the influence of the state of aggregation of carbon dioxide on the parameters of its distribution over heterogeneous layers during filtration is very insignificant. The nature of the distribution of CO_2 in heterogeneous reservoirs with the size of the rims of both 12% and 16% of the volume of the void space of the polygon object is similar, and the flow of the reagent into the low-permeability reservoir is facilitated by an increase in CO_2 and the number of rims. But this relationship is ambiguous. Thus, when the number of portions is less than 20, an increase in ratios of 1.5-3 entails a sharp decrease in the supply of carbon dioxide to a low-permeability formation.

Geological and hydrodynamic modeling of oil recovery using CO_2 rims in the pilot area. In the experimental area, the deposits coincide in plan and are separated from each other by D_1 and D_2 layers (Andreev et al 2019, Chizhov et al 2020, Chizhov et al 2020). Formation D_2 is underlain by bottom water over most of the area of the pilot area. Heterogeneity in reservoir permeability obeys a logarithmically normal distribution law with a variation coefficient of 0.79 and an average permeability value of 0.15×10^{-12} m^2. Data on the geological structure of the reservoirs, the type of reservoirs, and their heterogeneities are the basis of their geological and physical models. Their characteristics are shown in Figure 6.

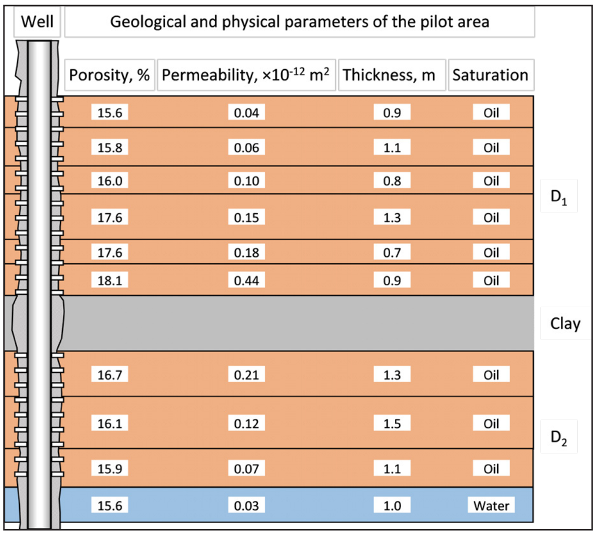

Figure 6. Average values of the parameters of the pilot area used in the simulation of oil displacement from the reservoirs of group D.

The thickness-weighted average values of permeability and porosity for the D_1 formation are 0.24×10^{-12} m^2 and 17.6%, and for the D_2 formation 0.133×10^{-12} m^2 and 15.77% respectively (Figures 6-8).

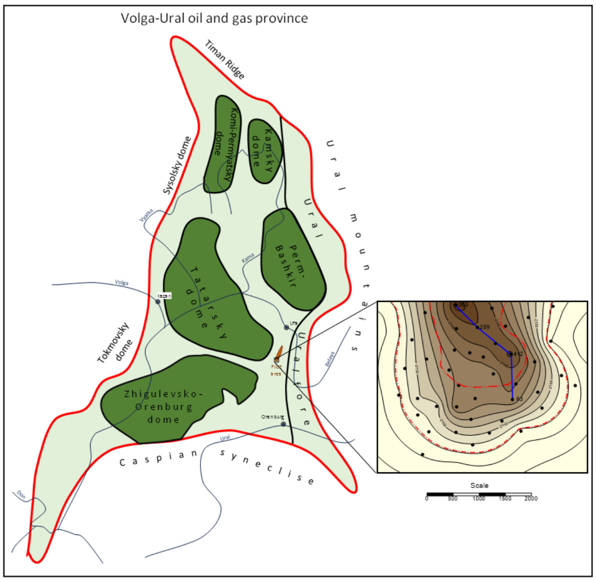

Figure 7. The location of the experimental site on the tectonic map of the Volga-Ural oil and gas province. The blue polygon indicates the geological profile along the line of wells Nos. 365, 259, 412, and 63.

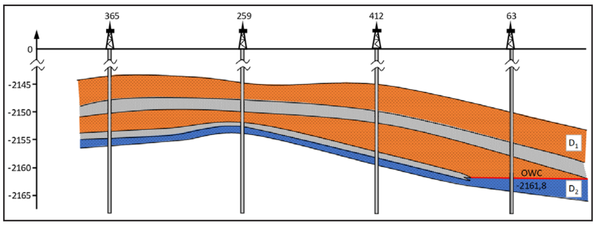

Figure 8. Geological section of the pilot area along the line of wells Nos. 365, 259, 412, and 63.

The calculation of technological indicators was carried out using a quasi-one-dimensional numerical model of the process of displacement of oil by CO_2. It also uses water in layered formations for a characteristic element of the formation (Andreev et al 2019, Chizhov et al 2020, Andreev et al 2020, Efimov et al 2021) and a special program for summing the indicators for the entire development object. The initial data for calculations are given in Table 8, and the additional data are as follows: At the existing formation pressure of 18 MPa and temperature of 40°C, the density and viscosity of the injected CO_2 and water are 0.79, 1.06 g/cm^3 and 0.076, 0.86 mPa×s respectively. The equilibrium values of the mass fraction of CO_2 in oil and water are 0.246 and 0.044. As a result of processing laboratory experiments on the displacement of oil by water and carbon dioxide, the following dependences of the relative permeability of the phases were established (Yamaletdinova et al 2020 , Andreev et al 2020,Chizhovet al 2019):

- for oil

$$K_{po} = \left(\frac{S_o^* - S_{or}}{1 - S_{or}}\right)^3 \times \left[1 + (3.58 \times S_g + 0.52) \times S_w\right], S_o^* > S_{or},$$

- for water

$$K_{pw} = \left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^2 \times 0.32,$$

- for gas

$$K_{pg} = \left(\frac{S_g - S_{gr}}{1 - S_{gr}}\right)^{3.5} \times (4 - 3 \times S_g),$$

Where

$$S_\alpha^* = S_{\alpha i} - \frac{S_{\alpha i} - S_{\alpha r}}{S_{\alpha i} - S_{\alpha r}(C_\alpha)}(S_{\alpha r} - S_\alpha),\ \alpha - \text{oil, water}.$$

Here, $S_{\alpha i}$ and $S_{\alpha r}$ are the initial and residual saturation with phase *α*. C_α is the coefficient taking into account the solubility of CO_2 in the α phase. Subscripts "*o, w,* and *g*" indicate that the parameters belong to the oil, water, and gas phases.

According to the development history, modified phase permeabilities were obtained. They have a form that differs in that the exponent in the expression for K_{po} is 3.3 (Chizhov et al 2019,Efimov et al 2019, Dubinsky et al 2018 , Andreev et al 2019, Bentahar et al 2023), and the factor in the expression for K_{pw} is 0.25. In addition, the parameters of the aquifer for the D_2 formation were refined (Table 9). The identification results are shown in Figure 9.

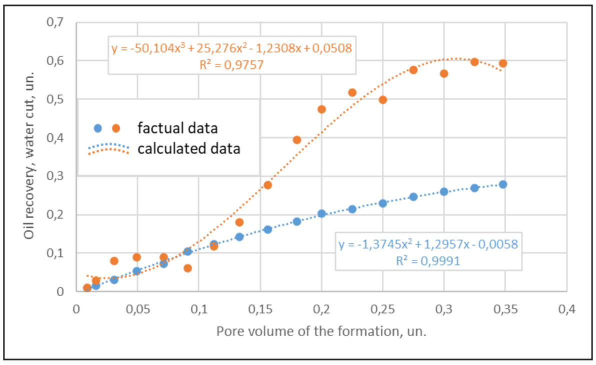

Figure 9. Dependence of oil recovery and water cut on the pumped liquid volume

Table 9. Initial data for determining development indicators

Options	Dimension	Values
Object area	m^2	6430000
Average depth	m	2150
Oil pay thickness	m	9.0
Porosity	%	16
Oil saturation: Initial Residual	%	 87 26
Geological reserves: Oil Gas	 million tons billion m^3	 5.24 0.26
Viscosity in reservoir conditions: Oil reservoir and injected water	mPa×s	 5.85 0.86
Permeability	×10^{-12} m^2	0.15
Permeability variation coefficient	%	79
GOR	m^3/t	49.0
Displacement ratio	%	70.0
Area sweep efficiency	%	92.5
Well operation factor		0.95
Initial formation temperature	°C	40
Initial reservoir pressure	MPa	23.6
Saturation pressure	MPa	9.7
Downhole pressure in production wells	MPa	13.0
Pressure at the mouth of injection wells	MPa	15.0
Discharge pressure	MPa	34.0
Pressure drops	MPa	21.0
Density in reservoir conditions: Oil Gas Water	g/cm^3	 0.842 0.00112 1.06
Conversion factor t of oil in surface conditions in m3 in reservoir		1.267

At the beginning of 2023, 69.6% of the recoverable oil reserves were withdrawn at the pilot site of the field with a water cut of 59.0%. The development is carried out using spot flooding. Due to the fact that CO_2 injection is limited to a supply of 40 thousand tons per year, the pilot facility-polygon is limited to 11 injection and 42 production wells. In these studies, the base case is development with water flooding. Development system parameters were as follows: in-loop flooding, triangular well pattern 500×500 m, density 153,000 m^2, injection to production well ratio 1:3.7. The options for injecting CO_2 rims and water into the D_1 and D_2 formations were modeled using the existing development system. In this case, the reservoir D_2 is covered by the impact of the reagent only within one injection site.

The calculations of technological indicators were preceded by numerical studies on a characteristic element of the development system to determine the best technology for injecting CO_2 and water into the Devonian formations. The processes of flooding, injection of a continuous slug of CO_2 pushed by water, an alternating slug of CO_2 and water with the ratio of their volumes in 1 injection cycle were 2:1, 1:1, 1:1.5, 1:2, 1:3, and 1:5. The analysis of the obtained simulation results showed that with a decrease in the CO_2 as follows: water ratio, the dynamics of the oil fraction and, accordingly, the current oil recovery deteriorate somewhat. However, early gas breakthrough and a rapid increase in the gas factor make the use of the continuous slug injection technology and the risky technology of alternating slug injection with a ratio of 2:1. Moreover, the increase in ultimate oil recovery for these options is lower than for technologies with CO_2: water ratios are 1:1, 1:1.5, and 1:2 (Table 10).

Table 10. Key technological indicators of development of D_1 and D_2 formations with different technology of carbon dioxide and water slug injection (total CO_2 slug - 0.2-pore volume)

Ratio of CO_2 and water slug volumes in one injection cycle	Oil recovery, %	Increase in oil recovery, %	Development period (conditional), years	Cumulative injection of agents, units	Water-oil factor by the end of development, m^3/m^3
Flooding	47.7	-	66.5	1.79	3.02
1 : 5	57.6	9.9	89.5	2.26	2.97
1 : 3	57.9	10.2	80.8	2.08	2.62
1 : 2	58.4	10.7	79.8	2.01	2.45
1 : 1.5	58.4	10.7	75.6	1.94	2.33
1 : 1.0	58.3	10.6	71.3	1.88	2.22
2 : 1.0	58.0	10.3	67.7	1.84	2.15
CO2 slug only	35.6*	12.1	22.0	0.59	0.66

*Note: Wells are shut down when GOR reaches 2000 m^3/t.

A comparison of the technological parameters of the options shows that the injection of CO_2 and water in a ratio of 1:1 is somewhat better than the others. With almost the same increase in oil recovery, there is a better dynamic of displacement characteristics, a shorter development period, and a lower water-oil ratio. Similar results were also obtained for ratios of 1:1.5, and 1:2. Nevertheless, from these three options, one should choose the option with a ratio of CO_2: water - 1:2, which represents the least risk of a premature breakthrough of carbon dioxide into production wells. For the selected technological ratio (CO_2: water - 1:2), various calculations were performed with different total carbon dioxide rim - 0.1, 0.2, and 0.3 of the pore volume of the polygon object. The calculation results are shown in Figure 10.

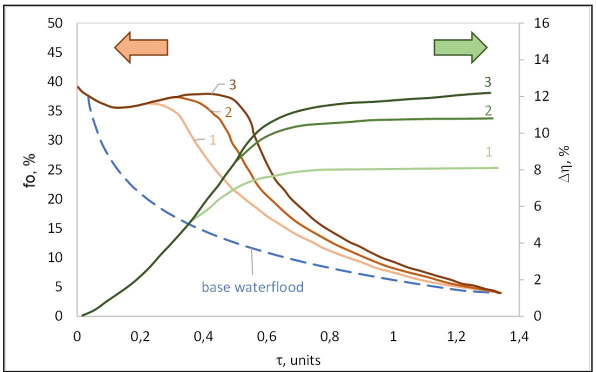

Figure 10. Dependence of oil recovery increment (Δη) and oil fraction (fo) on the withdrawn volume of liquid since the beginning of the method application at various CO_2 slug sizes. Numbers indicate the following: 1 - total CO_2 slug with a value of 0.1 of the pore volume of the formation; 2 – total CO_2 slug – 0.2 of the formation pore volume; 3 - total CO_2 slug - 0.3 of the reservoir pore volume

For these values, calculations of technological indicators of the development of the object under consideration were made. The recommended option is with a total CO_2 slug of 0.3 formation pore volume. The development options using enhanced oil recovery methods do not provide for a change in the number of production and injection wells and their location, compared to the base case. Only the water flooding technology changes. As of January 1, 2023, the current oil recovery in the D_1 and D_2 formations of the experimental area reached 27.4%, and the water cut was 59.2%.

It is assumed that the injection of carbon dioxide began in 2026 and by the beginning of 2028, 29.4 thousand tons will be injected. It is planned to inject carbon dioxide in the period up to 2046 in the amount of 0.3-pore volume of CO_2-covered reserves, which is formally 0.13 pore volume of the entire experimental area. The total consumption of CO_2 will be 789.4 thousand tons. The increase in oil production over the entire development period will be 298.6 thousand tons. 0.39 tons of additional oil will be taken per ton of spent reagent. The estimated total development period is 53 years. The increase in oil recovery due to the use of carbon dioxide will be 12.2%. The value of the ultimate oil recovery in layers D_1 and D_2 of the experimental area will reach 49.2%.

4. Conclusions

Based on laboratory studies to predict the development indicators of a pilot site on geological and hydrodynamic models of an oil field using carbon dioxide, the following data are presented as follows:

- Coefficient of oil displacement by water is 0.700 units;
- Distribution coefficient of CO_2 between oil and water and between oil and CO_2 phase is 1.83 and 4.28 units respectively;
- Increase in oil displacement coefficients for rims of 16, 21, and 30% of the pore volume of the formation is 0.089, 0.100, and 0.110 units respectively;
- Coefficient of oil displacement by carbon dioxide (CO_2 consumption 0.8 formation pore volume) is 0.918 units;
- Coefficient of oil displacement by carbonized water (CO_2 consumption 0.8 formation pore volume, CO_2 concentration - 4.4% wt.) is 0.766-0.780 units;
- The number of portions into which the CO_2 slug is divided is at least 20;
- The ratio of the volumes of portions of water and carbon dioxide is 1.5 or more.

Thus, the use of the parameters of the process of oil displacement by carbon dioxide rims obtained in the course of laboratory experiments, will make it possible to reasonably approach the implementation of the forecast of technological indicators for the recovery of residual oil reserves.

Modeling of oil recovery processes using CO_2 and water rims showed that the final oil recovery would increase by 12.2%, and an additional 0.39 tons of oil would be produced per ton of carbon dioxide.

Acknowledgments

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Conflict of Interests

The authors declare that there are no conflicts of interest regarding the publication of this paper.

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