

## JUSTIFICATION OF THE EFFECTIVENESS OF THE TECHNOLOGY OF LOW-MINERALIZED FLOODING FACTORY IN THE CONDITIONS OF FRACTURED CARBONATE RESERVOIRS OF THE OIL AND GAS CONDENSATE FIELD

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### ABSTRACT

One of the promising EOR technologies is a relatively recent technique of injecting low-salinity water into carbonate reservoirs. There are some Russian and foreign papers studying the effect of changing the injected water properties on the rate of production and reservoir recovery. Most of the studies analyze the effect of water composition on terrigenous reservoirs, while there are few studies concerning carbonate reservoirs. Therefore, development of carbonate reservoirs and their waterflooding, in particular, is of great interest. The paper discusses production target III of an oil and gas condensate field, composed of the Bobrikovian carbonate rocks. This heterogeneous, tight, fractured reservoir is currently developed under depletion drive. Reservoir stimulation is not provided by design, which indicates deficiency of field development strategy, preventing exploitation of full potential of this reservoir. To obtain an objective, a problematic zones in production target III has been analyzed. This analysis considered cumulative production against a thickness map between OWC and the upper carbonate reservoir. An extensive analysis of water sources was carried out for future use of this water as a reservoir-repressuring agent, as well as compatibility of the injected water, reservoir rock, and underlying groundwater was analyzed with regard to predicted chemical reactions. Laboratory testing of core samples was performed using a gas permeameter-porosimeter. For estimating efficient parameters of a reservoir pressure maintenance system is well interference study. Understanding well interference in carbonate reservoirs is complicated by natural fracturing, so, Express Pressure Tool data has been interpreted to analyze well interference.

**Keywords:** water flooding; injected water; salt content; reservoir rock; underlying groundwater compatibility.

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### 1. Introduction

Efficiency issues associated with low-mineralized water injection in carbonate reservoirs have arisen during the development of oil fields with small to medium reserves, which are at a late stage of development and characterized by high water cut in production [1]. Experience of various mineralization waters using when flooding layers collectors determines that at decrease in a mineralization of filtering liquid there is a decrease in permeability of breed. At the same time, the enhanced oil recovery resulting from low-mineralized water injection and particle migration contributes to an increase in sweep efficiency, which in turn depends on the mobility ratio of the phases [2]. Therefore, laboratory and field researches which will give a definite answer in a task of possibility of

use of a method of pumping the low-mineralized water are necessary for each separate case.

In Russia, Rosneft has investigated issues related to low-salinity water flooding. The company presented the results of field tests using Single Well Chemical Tracer Tests (SWCTT), conducted in the carbonate formation of the Kharyaginskoye field, to assess the residual oil saturation before and after low-salinity water flooding [3]. The results of numerical simulations of high- and low-salinity water flooding using the ECLIPSE 100 software are presented in a study dedicated to the development of an oil field located in the Niger River Delta [4]. The low-salinity flooding efficiency is characterized by the relationships between the effluent concentrations of fine particles and the reduction in sandstone core permeability. Based on these relationships, the core permeability damage factor is calculated [5]. Higher oil recovery factors can be achieved at lower permeability damage coefficients with

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Table 1

The producing well stock categorized by facilities and zones				
Sections	Center	North	East	West
Unit (wells quantity)	II Unit (27 wells)	II Unit (2 wells)	II + III Unit (4 wells)	III Unit (10 wells)
	II + III Units (37 wells)	II + III Units (7wells)		
	III Unit (32 wells)	III Unit (15 c wells)	III Unit (4 wells)	
Total wells quantity	96	24	8	10

proper well pattern design [6-10]. In addition to filtration modeling, a preliminary screening of terrigenous reservoirs of Tula, Bobrikov, and Devonian ages is performed based on geological and field data from several fields, followed by the identification of candidate fields. Positive factors include low reservoir temperature, high salinity of formation water, and elevated content of polar oil components [11]. Such properties are characteristic of specific unconsolidated reservoirs with high-viscosity oil and textural wettability [12]. High water cut combined with high viscosity can also be a decisive factor in choosing to implement low-salinity flooding [13]. The development method for such a highly water-flooded oil reservoir is described in sources [14-16].

The field under consideration is one of the largest oil-gas-condensate fields in the world. It was discovered in 1979 and put into production in 1985. The geological reserves of liquid hydrocarbons amount to 1.85 billion tons, and gas reserves to 1.68 trillion m<sup>3</sup>. As of January 1, 2022, about 13.6% of liquid hydrocarbons and about 12.9% of gas have been produced [17].

Three development targets have been identified at the field: Target I is the gas-condensate section of Lower Permian age; Target II is the gas-condensate section of Carboniferous deposits; Target III is the oil section of Carboniferous and Upper Devonian deposits.

The main reservoir at the field is an oil-gas-condensate reservoir of subsalt deposits of the Upper Devonian is Lower Permian. The reservoir type is mixed, and the geological structure of the reservoir is diverse.

Since 2006, the field has implemented gas re-injection technology (40% of produced gas volume) to maintain reservoir pressure and increase hydrocarbon recovery factors. This technology is implemented in accordance with the Development Technological Scheme [18].

The gas-oil contact is set at the level of 4950 m; this value is conditional due to gradual transition with increasing depth from one hydrocarbon phase to another. There is a zone of unstable (critical) phase state between the gas and oil sections. The division of the Carboniferous part of the reservoir into two Units (II and III) is also conditional. This division is driven by the need to categorize reserves during reserve estimation. The oil-water contact is set at a depth of 5150 m.

The oil-bearing portion of the reservoir lies between the gas-oil contact and the oil-water contact. There is no physical barrier between Units II and III. The separation of fluids between them is based on differences in their physicochemical properties (condensate vs. oil). In the lower part of the reservoir, there lies a sequence of Tula shales, reaching up to 40 m in thickness. This sequence effectively divides Unit III into two parts (pre-Tula and post-Tula deposits) and acts as

a barrier, impeding hydrodynamic communication between the layers. This is confirmed by different values of current reservoir pressure measured above and below the shale sequence.

The field is conditionally divided into sectors on the map: North, Center, East, and West [19].

The North section is located beyond a tectonic fault, which, according to the results of pressure dynamics analysis, acts as a fluid barrier within the reservoir [20]. Due to the fault, the northern part of the field exhibits reservoir fluid properties that differ from the rest of the field. This section entered development much later than the main part of the deposit, and reservoir pressure maintenance is not carried out here [21].

The remaining sections (Center, East, and West) are provisionally designated, as they are geologically connected as parts of a single deposit, without tectonic faults or property differences detectable in seismic data. However, analysis of reservoir pressure dynamics shows that, due to heterogeneity in reservoir properties and geological structure of the layers, the western part of the field features a distinct zone with high reservoir pressure [22].

Operational indicators of wells in the western section (condensate-gas ratio, gas factor, oil recovery factor) also differ from the average values for the field as a whole. These differences in the aforementioned parameters allow the West section to be identified for comparison with the main part of the deposit that is under development. The East zone also exhibits areas of depression funnel formation, as indicated by isobar maps, which signals the presence of hydrodynamic connectivity [23-24].

Table 1 presents the well stock producing from two Units (II and III); Unit I is under conservation.

## 2. Materials and methods

The analysis of hydrocarbon reserve depletion was carried out for three facilities.

Depletion across the sectors varies significantly, which is attributed to the high heterogeneity of the reservoirs. The most depleted sector is the Central area, where the gas recovery factor reaches 9.6% and the condensate recovery factor is 15% for Unit II. The least depleted remains the Eastern sector, with a gas recovery factor of 4.2% and a condensate recovery factor of 5.4%.

### Unit II:

The highest oil recovery factor is achieved in the Central sector of Unit II, where a reservoir pressure maintenance technology is currently in use, specifically, gas re-injection into the reservoir. This is supported by the following indicators: a high condensate recovery factor of 15%, compared

to the Northern sector. In the North, there are no injection wells, and the condensate recovery factor is 8.8% — despite nearly identical gas production rates in both sectors. A high condensate production rate per unit of reservoir pressure decline multiplied by the reservoir volume. This clearly demonstrates the effectiveness of the pressure maintenance system under the specific conditions of this sector.

The lowest reserve depletion is observed in the Eastern sector: the condensate recovery factor here is 5.4% and the gas recovery factor is 4.2%. Due to the incomplete drilling of this area (low well density), these figures are underestimated by nearly half. This suggests a much higher degree of reservoir depletion compared to the Northern sector. This is further confirmed by the condensate-to-gas ratio (also known as the condensate-gas factor): in the Eastern sector, this ratio is higher than in the Northern sector.

The low (lowest) specific condensate production in the Eastern sector indicates two key issues: small volumes of recoverable reserves; a weak impact of the applied reservoir pressure maintenance system.

The highest oil recovery factor is achieved in the Central sector of Unit II, where the technology of reservoir pressure maintenance through gas re-injection into the formation is currently being applied.

This is evidenced by the following indicators:

A high condensate recovery factor of 15% is compared to the Northern sector, where no injection wells are present and the condensate recovery factor is 8.8%, despite nearly identical gas production rates in these sectors.

A high level of condensate production per unit of reservoir pressure decline multiplied by the reservoir volume. This clearly demonstrates the effectiveness of the reservoir pressure maintenance system under the specific conditions of this sector.

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Unit III:

The highest reserve depletion is observed in the Central sector, where the oil recovery factor is 14.3% and the condensate recovery factor reaches 51.9%. The oil recovery factor value is considered minimal due to the assumption that all oil reserves present in the reservoir of this sector are involved in active development. The specific oil production in the Central sector reaches a maximum of  $98 \times 10^{-6}$  tons/MPa·m<sup>3</sup>.

The lowest reserve depletion is observed in the Western and Eastern sectors. This can be explained by the fact that these areas are currently being actively drilled and put into development. Consequently, their performance indicators are at a minimum level, consistent with the initial stage of development. In the future, as drilling progresses, it will be possible to: assess the degree of reserve depletion in these

sectors; conduct development analysis; improve the existing reservoir pressure maintenance system or design a new reservoir stimulation system is tailored to the current requirements, capabilities, and specific characteristics of each sector.

The target focus of this study is Facility III of the oil-gas-condensate field (particularly the pre-Tula interval), composed of carbonate rocks from the Bobrikovian horizon.

This heterogeneous, dense, fractured reservoir is currently being developed under a depletion drive regime. The absence of reservoir stimulation underscores the limitations of the current development strategy and prevents unlocking the full potential of the oil-saturated horizon.

Within Unit III of the field under study, a problematic area has been identified — the pre-Tula deposits. This zone is characterized by: low reservoir porosity and permeability (filter-capacity properties); a thickness reaching up to 300 m above the oil-water contact (OWC) in the ridge of Structure C9, extending northward toward the central part of the field; proximity to the edge of the Devonian carbonate platform.

Although 145 wells penetrate this area, their productivity varies greatly due to sedimentary and structural heterogeneities within the reservoir. The reservoir has a long history of production from conventional vertical wells, although recent vertical well completions/deepening efforts into the Pre-Tula formation have been unsuccessful. Due to the reservoir's high compartmentalization and heterogeneity, there are both highly productive wells (so-called «sweet spots») and completely non-producing wells. It was found that wells penetrating the central portion of the reservoir have demonstrated a low current recovery factor for the interval under consideration (5%), despite the high estimated volumes (173 million m<sup>3</sup> of liquid hydrocarbons) in this zone.

Wells in Unit III, producing from pre-Tula deposits, are characterized by a low initial gas-oil ratio, which tends to increase more gradually over time compared to wells producing hydrocarbons from post-Tula deposits. To increase production from this interval, an enhanced oil recovery method is proposed, using water injection into the pre-Tula interval.

In-place oil reserves are estimated at 133.3 million tons. According to Production Logging Test (PLT) data, only 11 wells are producing hydrocarbons, of which only two wells are producing entirely from the pre-Tulian formations, and nine others are producing in combination with overlying intervals. The proportion of oil inflow from the pre-Tulian formations in wells with combined production from different intervals ranges from 4.6 to 94 %. The overall estimated oil production in this formation, based on PLT data, is 5.2 million tons at a 3.9% recovery factor.

Currently, no reservoir pressure maintenance (RPM) system is planned for the pre-Tulian formation section of development Unit III. To address the low oil recovery and enhance its performance in this target, it is necessary to analyze and identify the potential for reservoir flooding using water with salinity compatible with the formation rock and the reservoir water to avoid potential precipitation during flooding. Although gas reinjection is used to maintain reservoir pressure at Units I and II of the field, it is not considered for Unit III (specifically, the Dotula deposits), as miscible oil-gas displacement may prove ineffective. The high heterogeneity of the reservoir and the presence of fractures further complicate the selection of an appropriate

injected agent. It should be noted that water may also prove ineffective as a displacement agent in low-permeability, oil-hydrophobic carbonate formations, as when injecting water into a real carbonate formation containing fractures, the water will filter through the fractures, virtually preventing penetration into the rock matrix. Injecting water with modified salinity, matched to the composition of the formation, into a carbonate reservoir can change the wettability of the rock to hydrophilic, thereby significantly increasing the efficiency of oil displacement by water.

To assess the feasibility of injecting low-mineralized water into the section of an oil and gas condensate field under consideration, it is necessary to analyze the formation water, the composition of the rocks that make up the formation, and the formation temperature, since temperature is one of the key factors influencing the rate and efficiency of reactions between the injected water and the carbonate rock.

The results of laboratory tests are presented below.

The data and results of the air permeability calculation are given in table 2.

It should be noted that during the experiment, the temperature was 20.7-20.9 °C, and the air viscosity was 0.01817 mPa·s.

Subsequently, the water permeability was calculated at 100% water saturation. The data and calculation results for water permeability are presented in table 3.

Three key parameters were selected for systematization: bottomhole pressure, cumulative production, and gas-oil ratio. A graph of well flow rate changes over time was also included for analysis.

Modeling of possible process solution scenarios for Unit III (Pre-Tulsk deposits) was conducted using the Eclipse soft-

ware suite. Using a hydrodynamic model, several injection well placement options were selected, each scenario was simulated, and results were obtained. The main criteria for injection well placement were the results of production well connectivity studies, reservoir properties in the area ( $k \cdot h$  and  $m$  data in the model), and reduced reservoir pressure in certain areas. In figure 1, the inactive area is highlighted in blue; the area under consideration is colored from bluish-green to red depending on oil saturation.

The model was then divided into polygons to recreate the thickness map. To do this, a polygon was again selected within the sector using the ACTNUM command. Consequently, sections with thicknesses less than 173 m and with low reservoir properties were deactivated, allowing for faster computations.

It should be noted that due to the presence of inactive cells (primarily the «disabling» of cells I and II of Units), the reservoir pressure in the model dropped, which subsequently had to be compensated for by artificially lowering wellhead pressures (on average, wellhead pressure was set at 70 bar instead of the original 80 bar). Reserves in the polygon amount to 59.51 million m<sup>3</sup>.

When distributing reservoir pressure within the polygon in the hydrodynamic model, the following results were obtained. The southeastern section is the most promising for further drilling: high reservoir pressure and oil saturation provide the opportunity to add a new production well (in our modeling, we also considered adding a horizontal well, which, according to the model, could increase the recovery factor by approximately 1.5% of the total reserves of Unit III). The field is currently considering horizontal well placement options in this area, and the southeastern part of the Dotulsky

Gas injection rate Q, cm <sup>3</sup> /min.	Input pressure P1, MPa	Output pressure P2, MPa	Pressure difference dP, MPa	Air permeability k, 10 <sup>3</sup> μm <sup>2</sup>
20.83	0.39	0.01	0.38	0.598
29.48	0.49	0.01	0.48	0.536
40.62	0.59	0.01	0.58	0.509

Water flow rate Q <sub>B</sub> , cm <sup>3</sup> /min.	Pressure difference dP, MPa	Water permeability k, 10 <sup>3</sup> μm <sup>2</sup>	Average permeability k <sub>cp</sub> , 10 <sup>3</sup> μm <sup>2</sup>
0.1	2.048	0.053	0.04735
0.05	1.102	0.049	
0.025	0.598	0.045	
0.01	0.258	0.042	

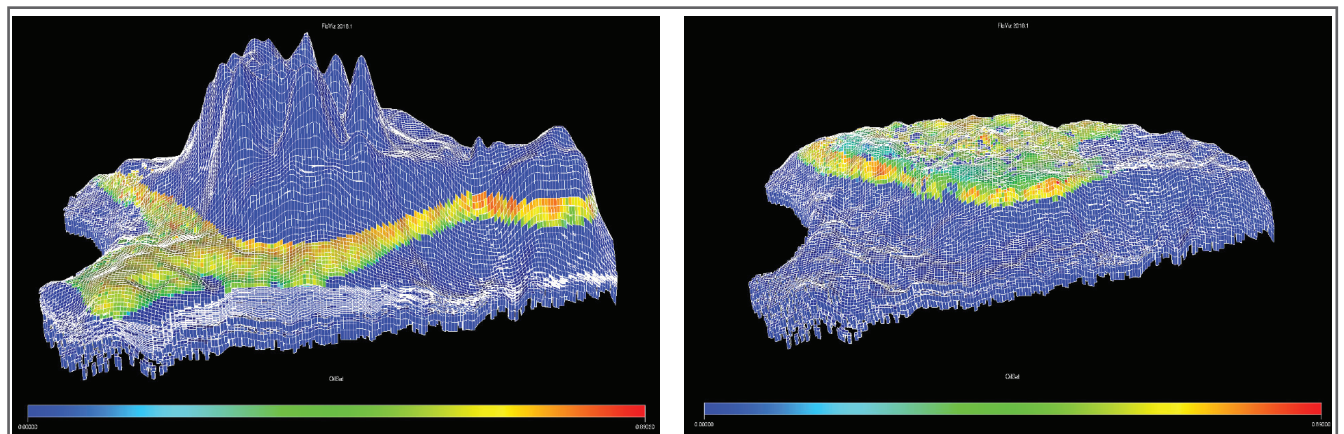
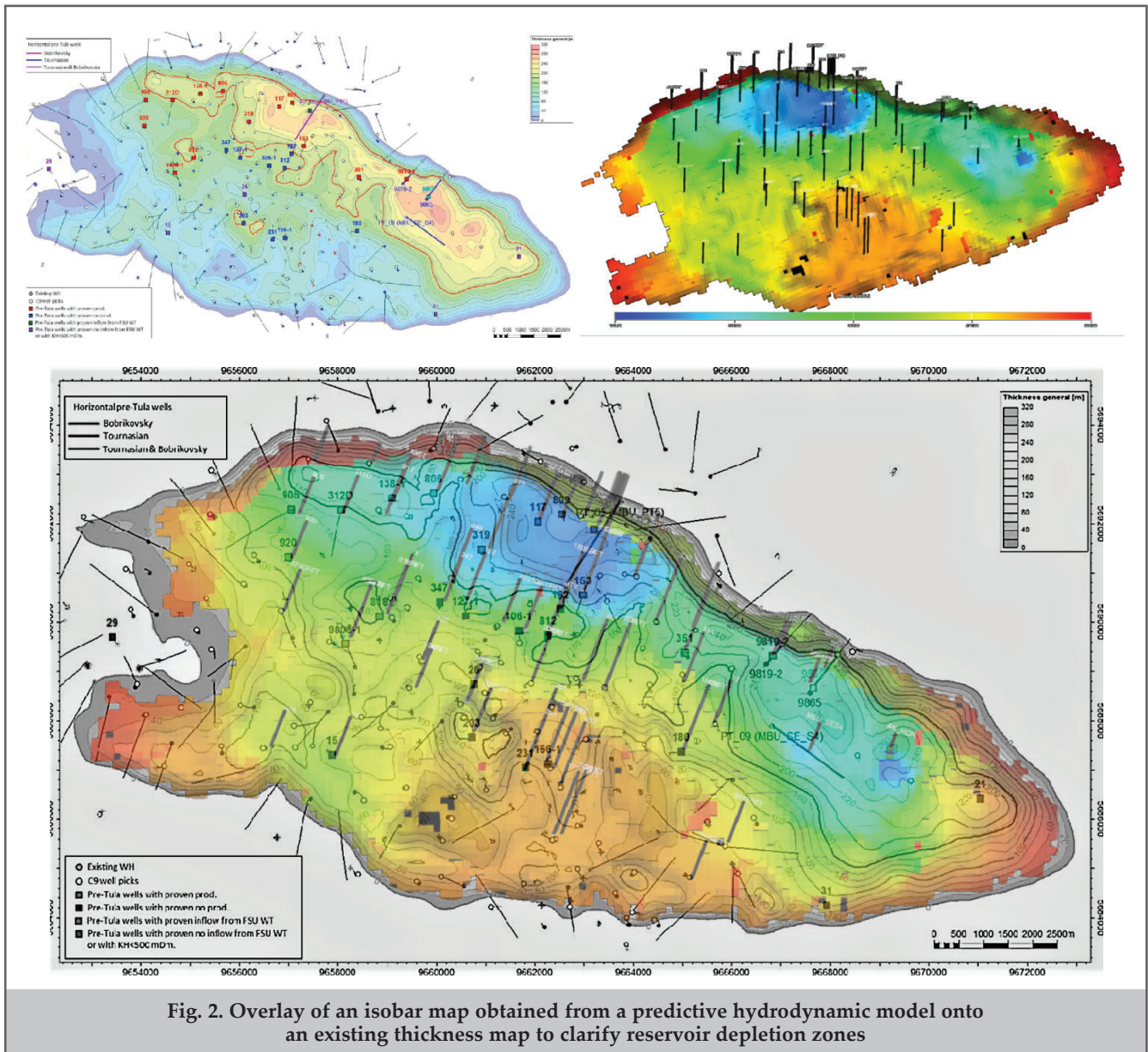


Fig. 1. Extraction of a sector model to isolate it from overlying formations

interval is planned for drilling in the near future.

The northern and part of the central region of the sector: reservoir pressure is depleted, however oil reserves remain, which can be recovered through artificial enhancement and maintenance of energy.

For clarity, thickness maps from the development flow-sheet and an isobar map obtained from the hydrodynamic model were superimposed, and the thickness map and oil saturation were integrated. This combination of maps allows for a complete picture of the reservoir (fig. 2).



### Conclusions

Global experience with carbonate reservoir flooding shows that the success of waterflooding depends primarily on the degree to which the waterflooding system matches the geological features of the reservoir. Important considerations include the placement of injection wells based on the zonal heterogeneity of the reservoir, the relative positions of wells (producer and injection) within the development elements, and the location and orientation of fracture systems. The wettability of the rocks composing the reservoir also plays a significant role in waterflooding carbonate reservoirs. Most carbonate rocks are hydrophobic, which calls into question the effectiveness of waterflooding for such reservoirs.

One solution is low-salinity waterflooding. Developing a rational waterflooding system for a carbonate reservoir requires careful analysis and understanding of the physical processes occurring in the «injected agent-oil-rock» system.

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