SOCAR

SOCAR Proceedings

Reservoir and petroleum engineering

journal home page: http://proceedings.socar.az

EMERGING SOURCES CITATION INDEX

Scopus

DEVELOPMENT OF TECHNOLOGY FOR INTENSIFICATION OF OIL PRODUCTION USING EMULSION BASED ON NATURAL GASOLINE AND SOLUTIONS OF NITRITE COMPOUNDS

A. T. Zholbassarova[1], R. Y. Bayamirova[1], B. T. Ratov[2], V. L. Khomenko*[3], A. R. Togasheva[1], M. D. Sarbopeyeva[1], M. T. Tabylganov[1], D. S. Saduakasov[1], A. G. Gusmanova[1], Ye. A. Koroviaka[3]

[1]Yessenov University, Aktau, Kazakhstan; [2]Satbayev University, Almaty, Kazakhstan;
[3]Dnipro University of Technology, Dnipro, Ukraine

A B S T R A C T

This article focuses on the issue of enhancing oil production by eliminating asphalt, resin, and paraffin deposits (ARPD). These deposits pose significant challenges, including equipment clogging, reduced well productivity, and increased maintenance costs. Moreover, paraffin deposits can damage well equipment, cause accidents, and halt hydrocarbon production. The study involved laboratory and field experiments at the Uzen field to evaluate the efficiency of removing and dissolving paraffin using an emulsion composed of gas gasoline and nitrite compound solutions. Previous studies conducted at NGDU Uzenneft were critically analyzed for comparison. The scientific innovation of this research lies in the development of an emulsion based on gas gasoline and nitrite compound solutions to remove ARPD. The composition was designed to exclude highly aggressive components. It utilized a previously developed emulsion base and incorporated ammonium nitrite, slightly acidified with hydrogen chloride (0.1% by mass), to promote an exothermic reaction.The effectiveness of this technology was measured by changes in daily oil production rates, the duration of the treatment's effect, and changes in the well productivity coefficient before and after treatment.Results indicate that the developed technology successfully removed paraffin from the bottomhole zone of oil wells and increased oil production in 5 out of 6 wells at the Uzen field. The positive effect lasted 17-27 days, with oil inflow increasing by 17-174%. This led to a total additional oil production of 1528 tons from the five wells.

Keywords: bottomhole formation zone; asphalt-resin-paraffin deposits; nitrite composition; surfactants; enhanced oil recovery.

Date submitted: 18.01.2024 **Date accepted:** 20.05.2024

1. Introduction

Boosting oil production is crucial for Kazakhstan's economy, as the oil and gas sector stands as a cornerstone of the country's economic framework, contributing substantially to its financial stability and overall development. With abundant oil reserves, Kazakhstan relies heavily on oil exports to generate revenue, with oil production revenues constituting a substantial portion of the state budget. Furthermore, the oil and gas sector's development attracts both domestic and foreign investments and serves as a major employment provider within the country.

Scientific research aimed at enhancing oil production is being pursued along the following key areas.

1. Horizontal drilling technologies: This technique enables oil extraction from deep formations or areas inaccessible to vertical drilling, thereby expanding the filtration area within the productive formation and enhancing well production rates [1, 2].
2. Hydraulic fracturing: This technique involves creating fractures in rocks to enhance formation permeability, facilitating improved oil flow to the well. By injecting specialized fluids (proppants) at high pressure into the well, rock fractures are induced, allowing for increased oil accessibility and production [3-5].
3. Advancements in well construction equipment and technology: The development and utilization of innovative drill bit designs and materials play a pivotal role in enhancing drilling efficiency. These advancements enable more effective rock penetration, increased drilling speeds, and reduced equipment wear, consequently augmenting production volumes.
4. Secondary and tertiary recovery technologies: These methods target the extraction of additional oil reserves from fields where initial production was suboptimal. Secondary recovery techniques involve injecting water, steam, or gas into formations to maintain pressure, while thermal recovery entails heating formations to boost oil flow. Chemical stimulation methods utilize chemicals to enhance oil displacement.

**E-mail:* inteldriller@gmail.com
http://dx.doi.org/10.5510/OGP20240200965

Oil companies integrate these technical approaches to bolster oil production, enhance operational efficiency, and optimize costs. Their combined implementation not only facilitates increased oil production but also contributes to the stability and advancement of Kazakhstan's oil industry.

Currently, the primary approach to enhancing oil recovery during field development is through waterflooding, a method extensively researched within the industry for extracting oil from underground reservoirs. However, as many fields in Kazakhstan have reached an advanced stage of development, there's a pressing need to explore and investigate methods facilitating the efficient extraction of remaining oil reserves. It's well understood that, globally, up to 30% of total oil reserves are typically recovered during the primary and secondary stages of development in oil production practices.

The objective of the third stage is to recover a portion of the remaining 70% of oil [6]. Various methods are employed for this stage, including carbon dioxide injection, steam injection, and well treatment using surfactant solutions in the form of micellar, microemulsion, or emulsion solutions.

The essence of these research methods lies in achieving low surface tension values within the hydrocarbon-rock system. The hydrocarbon may consist of either oil or solid particles of paraffins and asphaltenes. Additionally, surfactants solutions help cleanse water from the formation zone of production wells exhibiting low productivity due to water intrusion during drilling or repairs [7]. Temperature also plays a significant role in reducing surface tension, thus aiding in the recovery process.

It's a recognized fact that higher temperatures enhance the effectiveness of the ebb process. However, achieving a hot emulsion (microemulsion) necessitates specialized heating equipment such as well dewaxing units or steam generators. Economically, it's more viable to employ solutions that undergo spontaneous chemical reactions, releasing substantial heat.

The paper [8] discusses the issues pertaining to field development, identifying causes behind well productivity issues. It provides instances and explanations regarding the formation of paraffin deposits. New methods have been developed to address challenges in well operation. An inventive approach to combat asphalt, resin, and paraffin deposits (ARPD) has been introduced, which entails employing a dip container housing a multifaceted inhibitor. The formula for this inhibitor is outlined, along with a technological schematic of the container's setup. The technological efficacy of the inhibitor in preventing ARPD has been proven.

Moreover, the contamination of the bottomhole formation zone (BHFZ) significantly impacts well performance. Accumulation of sand, corrosion byproducts, and salts diminishes the operational efficiency of the well [7].

There are various methods to enhance oil extraction efficiency.

Paper [9] discusses an experimental study on the use of nanofluids to improve oil recovery. The study focused on an aqueous solution of anionic surfactants with added light nanoparticles of non-ferrous metals. The findings revealed that the developed nanosuspension significantly improved the efficiency of the oil displacement process. Specifically, the oil displacement rate using the nanofluid increased nearly 1.5 times compared to the aqueous solution of an anionic surfactant and 4.7 times compared to water alone.

Water flooding with low salinity water and the use of nanofluids to enhance oil recovery and more effectively displace trapped residual oil were studied in [10]. The research demonstrated that these reagents alter the wettability of the rock's pore walls, reduce interfacial tension, decrease oil viscosity, and increase disjoining pressure. The paper presents findings from experiments on residual oil displacement in homogeneous quartz sandstone using nanofluids obtained by peptizing sediments in a seawater-sodium carbonate mixture, both with and without the addition of PEG8000. The use of these nanofluids resulted in a 15-20 % increase in oil production compared to seawater alone.

Additionally, the potential of nanotechnology to enhance oil production was investigated in [11]. The study presents experimental results on the impact of a system based on metal and organic clusters on the porosity of a porous medium. It was determined that this developed system effectively regulates the water permeability of the porous medium.

Article [12] explores the application of softened water (SW) in secondary and tertiary enhanced oil recovery methods. The study analyzes the effects of low salinity water (LSW) and low hardness water (SofW) on reducing surface tension, altering contact angles, adsorption, emulsion stability, and clay swelling. The findings show that using SW results in more stable emulsion formation and reduced clay swelling. Specifically, using SofW-2 and SofW-1 as displacement agents during secondary displacement increased the oil recovery factor in the dry period by over 29% and 25% respectively, compared to synthetic seawater (SSW) injection, with final oil production increases of 21% and 15%. In tertiary flooding, the oil recovery increased by 13% and 10% for SofW-2 and SofW-1 respectively, compared to LSW injection.

The synthesis of new, improved gels with preformed particles based on 2-acrylamido-2-methylpropanesulfonic acid (AMPS), polyvinylpyrrolidone (PVP), and bentonite clay was examined in [13]. N,N′-methylenebisacrylamide was used as a cross-linking agent, and ammonium persulfate as an initiator. The inclusion of clay in the polymer matrix, the intercalation of AMPS between layers, and the hydrophilic interactions between components resulted in final preformed gels with a higher degree of swelling, a slower swelling process, high thermal stability, and improved mechanical properties compared to pure gels with preformed particles.

A method to enhance oil recovery from highly viscous oil formations through reservoir modification of physicochemical properties is discussed in [14]. The in situ combustion process is highlighted as one of the most promising strategies for heavy oil fields. However, its economic efficiency and large-scale industrial application remain limited. In situ combustion involves injecting high-pressure air into a formation to oxidize a small portion of the hydrocarbons, which serves as fuel. This process significantly reduces the oil's viscosity, enabling heavy oil to flow more easily through the porous media.

Among the various chemical methods to enhance oil recovery, the traditional use of polymer-based solutions remains predominant. One of the most promising technologies involves polymer liquids that lack a three-dimensional polymer structure. Notably, colloidal dispersion systems are particularly effective as they can simultaneously regulate the water-oil mobility ratio and modify the permeability profile.

The paper [15] explores the behavior of colloidal dispersed gels in porous media with varying salinity levels of formation water. Rheological measurements and experiments on particle size distribution were conducted. The findings indicate that divalent ions significantly reduce viscosity by forming a harder electrolyte, and the average particle size decreases with increasing ionic strength. The presence of divalent ions also enhances propagation, likely due to increased repulsive forces.

In reservoir conditions, oil exists in a state of thermodynamic equilibrium. However, during the process of oil production, this equilibrium is disturbed as the oil transitions from reservoir conditions to surface conditions. This transition leads to the release of hydrocarbon gases, paraffin, resins, and asphaltenes from a complex mixture of hydrocarbons. These substances deposit on the internal surfaces of pipes, obstructing fluid flow. Consequently, the primary complication encountered is the formation of asphalt, resin, and paraffin deposits (ARPD) [16-18].

In [19], it was emphasized that the accumulation of paraffin in pipelines poses a significant challenge across various stages of crude oil production, transportation, storage, and processing. To avert complete blockages, it's imperative to minimize and eliminate wax deposits in pipelines and tubing. Extensive research has been conducted to comprehend the mechanisms underlying paraffin formation and its constituents. This review scrutinizes the current state of research and the potential for occurrence and characteristics of wax formation in crude oil wells and pipelines, offering a critical analysis. Various methods for detecting wax and controlling wax-related issues in oil production have been deliberated upon. Furthermore, this review underscores the impact of temperature and the type of crude oil on wax formation.

Crude oil serves as the primary energy source worldwide, encompassing a multitude of hydrocarbons classified into four fractions: saturated (aliphatic), aromatic compounds, resins, and asphaltenes. The characteristics of crude oil undergo variation with temperature, with certain petroleum liquids prompting the crystallization of wax at lower temperatures [20-23]. The liberated paraffin then deposits on pipeline walls, posing extraction challenges and impeding the throughput of crude oil pipelines [19, 24, 25]. Crude oil harbors substantial quantities of wax within the range of 3–44 %, prone to crystallization and precipitation during production and transportation, which in turn elevates oil viscosity and pour point. Elevated viscosity and pour point values contribute to pressure drops, gelation, reduced fluidity, and increased pumping expenses [26-28]. Ceresins, typically aliphatic and non-polar compounds of high molecular weight, exhibit limited solubility in crude oil and can aggregate or associate in solution.

The deposition of wax in pipelines and tubing presents significant and expensive challenges in separation [19, 29, 30]. It's imperative to comprehend the mechanisms and factors underlying the formation and stabilization of these emulsions for economic and environmental progress.

In practice, various chemical and thermal methods are employed to enhance well productivity by influencing the reservoir zone. Thermal methods such as electric heating and explosive techniques facilitate the melting of solid deposits solely within the BHFZ. However, once the temperature stabilizes, the paraffin re-solidifies, leading to further deposition either within the formation or equipment [31-33].

Chemical methods of treatment, such as the utilization of unsaturated or aromatic hydrocarbon solvents, facilitate partial dissolution of paraffin particles within the pore channels of the BHFZ. However, without elevated temperatures, these solvents cannot effectively conduct complete post-washing of paraffin to mitigate filtration resistance in oil reservoirs [34-36].

Consequently, it has been deduced that developing compositions and methods capable of delivering simultaneous chemical and thermal effects on the BHFZ is advisable.

In oil field practices, a method involving thermochemical influence on the reservoir zone employs magnesium chloride through the reaction of granulated magnesium with hydrochloric acid (15%). Despite the presence of hydrochloric acid in the composition, the complete dissolution of ARPD is hindered due to the absence of a hydrocarbon solvent in the composition [37-39].

Additionally, in oil production, another thermochemical method involves the blending of sulfuric acid with a 17% aqueous solution of ammonium bifluoride. This blend raises the solution's temperature from 20 °C to 82 °C, which proves sufficiently high for complete ARPD melting. During well treatment, molten ARPD migrate deeper into the formation, gradually dissolving in the hot formation fluid, albeit not entirely [40, 41]. The incomplete dissolution is attributed primarily to the reservoir oil's insufficiently high temperature and its low dissolving capability, exacerbated by its supersaturation with asphalt, resin, and paraffin substances. The primary hindrance to ARPD dissolution within the formation's pores is, once again, the absence of a hydrocarbon solvent (unsaturated or aromatic) in the treatment composition [42-44].

The objective of this study is to develop a technology for removing asphalt-resin-paraffin deposits (ARPD) from the bottomhole formation zone of oil well using an emulsion based on natural gasoline and solutions of nitrite compounds.

2. Objects and methods of research

The oil-and-gas production department Uzenneft conducted trials on an alcohol-sulfuric acid mixture in oil wells [45]. During the formulation process, various types of alcohols were considered, with a focus on monohydric alcohols, starting from ethyl alcohol. Test results indicated that lower alcohols, particularly ethyl alcohol, exhibited the highest effectiveness. Conversely, higher alcohols like isopropyl and butyl significantly diminished the efficiency of the exothermic reaction. Regarding sulfuric acid, it was found that only higher concentrations, particularly concentrated sulfuric acid, yielded optimal results. Decreasing the concentration of sulfuric acid reduced the final effect of the exothermic reaction (i.e., the final temperature), and using alkylated sulfuric acid (70% concentration) not only lowered the final reaction temperature but also necessitated additional heating of the heavy alkyl precipitate of the acid, further diminishing the effectiveness of the method. Consequently, the alcohol-sulfuric acid mixture tested by the oil-and-gas production department Uzenneft failed to deliver the required effectiveness due to procedural errors. To enhance the thermochemical treatment technology of the BHFZ, a new, simpler, and more effective composition has been developed, which generates heat by combining a detergent emulsion composition with acidified ammonium nitrite.

During the composition's development, it was established that highly aggressive components such as sulfuric acid should not serve as the primary constituents. The foundation of the composition relied on a previously successful emulsion composition validated at various fields in Kazakhstan [46-49]. Additionally, a substance fostering an exothermic reaction during the composition's preparation, namely ammonium nitrite slightly acidified with hydrogen chloride (0.1% by mass), was incorporated. Ammonium nitrite was synthesized by blending ammonium chloride with sodium nitrite.

Taking into account the varied bottomhole temperatures observed in different oil wells across fields, it was decided to initiate the exothermic reaction process not from room temperature but from elevated temperatures corresponding to those at the bottom of Kalamkas and Uzen wells, namely 40, 50, and 60 °C [50]. Subsequently, the final temperature was set at 100 °C. Given that ammonium nitrite constitutes one of the two primary components, studies were conducted to determine the optimal concentration of ammonium nitrite across five different levels (wt. %): 11, 10, 9, 8, and 7. The optimization of ammonium nitrite concentration was based on two factors: the quantitative content of the reagent in the composition and the pH of the environment. To achieve this, hydrochloric acid was added to the prepared composition solution in amounts ranging from 0.05% to 0.15% by weight. Consequently, the pH of the environment shifted from 6.7 to 4.5 across all possible ratios of ammonium nitrite and hydrochloric acid. The results of studies of the dependence of the pH environment on the content of reagents in the emulsion are given in table 1.

As depicted in eable 1, for the sake of simplicity, the study was conducted at a uniform initial temperature, as the solution's temperature does not impact the pH environment. The results presented in Table 1 indicate that the resulting compositions consist of ammonium nitrite contents of 10% and 11% by weight, both with the addition of HCl at 0.1% and 0.15% by weight. However, the preference lies with a lower component content. Thus, compositions containing 10% and 11% by weight of NH4NO2 with an HCl content of 0.15% by weight are deemed more favorable. Further optimization of the composition permits an increase to 9% ammonium nitrite content, as this concentration yields a sufficiently high temperature of the exothermic reaction (90 °C), enhancing the potential dissolution of any of the most stubborn components of asphalt-resin-paraffin deposits.

After determining the optimal concentration of ammonium nitrite at a higher pH, requiring less hydrochloric acid consumption, further research is conducted to develop the composition. This involves assessing the potential effectiveness of the compositions at various initial temperatures, specifically 40, 50, and 60 °C.

Consistently with logical expectations, the least efficient result was observed at an initial temperature of 40 °C. However, with an ammonium nitrite content of 11% in composition 1, the final temperature, along with higher initial temperatures (50 and 60 °C), exceeded 100 °C. Yet, at 10%, the reaction temperature sharply dropped to 82 °C, and so forth. Given the previously discussed efficiency results at an initial temperature of 50 °C, the most effective ammonium nitrite content is determined to be 9 and 10%. It›s important to note that for each composition containing from 7 to 11% ammonium nitrite, calculated indicators for each of the two components must be considered. Table 2 presents the calculated and practically utilized volumes of sodium nitrite and ammonium chloride in the composition under investigation.

Certain disparities between the calculated (theoretical) component content indicators and the empirical values obtained in practical experimental settings may stem from inadequate thermal insulation during the exothermic reaction process and other inaccuracies in obtaining both calculated and experimental data.

Figure 1 provides the reaction parameters for preparing the emulsions under investigation.

Table 1

Dependence of the pH environment on the content of reagents in the emulsion

Composition	Content, % mass		Initial reaction temperature, °C	pH of the environment	Final reaction temperature, °C	Temperature difference, °C
	ammonium nitrite	hydrochloric acid				
1	11	0.05	50	6.7	56	6
2	10	0.05	50	6.6	55	5
3	9	0.05	50	6.5	53	3
4	8	0.05	50	6.4	52	2
5	7	0.05	50	6.3	52	2
6	11	0.1	50	5.8	100	50
7	10	0.1	50	5.7	100	50
8	9	0.1	50	5.6	90	40
9	8	0.1	50	5.5	85	35
10	7	0.1	50	5.4	72	22
11	11	0.15	50	4.9	100	50
12	10	0.15	50	4.8	100	50
13	9	0.15	50	4.7	92	42
14	8	0.15	50	4.6	90	40
15	7	0.15	50	4.5	77	27

Table 2

Content of components in the composition under investigation

Composition	Content of components in the composition, %				
	NH_4NO_2	$NaNO_2$		NH_4Cl	
		calculated	empirical	calculated	empirical
1	11	12	12	11	9
2	10	11	11	9	8
3	9	10	10	9	8
4	8	9	9	8	7
5	7	8	8	7	6

After preparing the requisite quantity of ammonium nitrite, it is dissolved in water along with other water-soluble components. Subsequently, 30% natural gasoline is added and thoroughly mixed. Following this step, hydrochloric acid is added in the range of 0.1% to 0.3% by weight to adjust the pH of the solution to the desired level. The resulting composition is then heated to 50 °C. At this point, an exothermic reaction initiates, with its speed determined by the quantity of added acid. Typically, under the specified component ratios, the temperature rises over a period of approximately half an hour to 60 minutes. To extend the duration of temperature elevation, a reduction in hydrochloric acid addition by 0.05% by weight or similar adjustments may suffice. Once the maximum temperature is attained, cooling ensues over an extended duration compared to the heating process. This is primarily due to the exothermic reaction reaching a steady state upon reaching the peak temperature.

3. Research results and discussion

In laboratory conditions, an efficiency assessment was conducted to explore the characteristics of the composition both during and after the exothermic reaction, aiming to determine the optimal application mode of the developed composition. Initially, the density of the resulting composition was measured, yielding 0.932 g/cm^3. To examine the relationship between heating time and composition volume to reach the final temperature, different volumes of the composition were tested: 50, 100, and 200 ml. Observations revealed that the first volume reached the desired temperature within 12 minutes, the second within 21 minutes, and the third within 42 minutes during the exothermic reaction. Subsequently, the cooling time for the last volume to return to the initial temperature (50 °C) was observed to be 105 minutes, precisely 2.5 times longer.

Furthermore, investigations were carried out to assess the efficacy of eliminating asphalt, resin, and paraffin deposits from both metal and porous surfaces of cores. Concurrently, metal mesh cylinders were set up to evaluate the dissolution efficiency of ARPD.

To achieve this, a U-shaped laboratory cell was employed, comprising two cylinders: one for holding samples and the other for housing a laboratory stirrer to facilitate composition circulation. Metal plates and specialized small core samples were utilized, onto which a measured volume of paraffin was applied. After weighing, the samples were suspended in the cell, and the stirrer was activated. Prior to this, the composition within the cell was preheated to the initial temperature, completing the exothermic reaction and raising the liquid to the final temperature. The time taken and efficiency of ARPD removal are detailed in figure 2. Despite varying exposure durations, tests indicated that when the composition was heated to 85 °C and above, the duration of ARPD removal and dissolution remained approximately consistent. The most resilient paraffin (melting point is 85 °C) was employed for testing purposes.

As indicated in figure 2, the duration required for dissolution surpasses that for removal (at temperatures below 85 °C). This is because the dissolution process initially

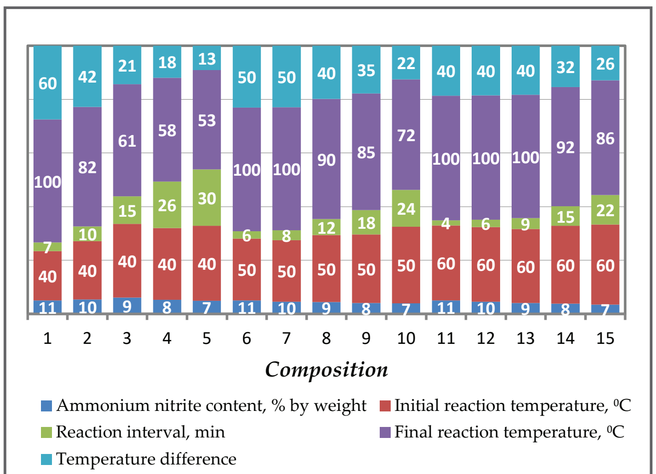

Fig. 1. Reaction parameters for preparing the emulsions under investigation

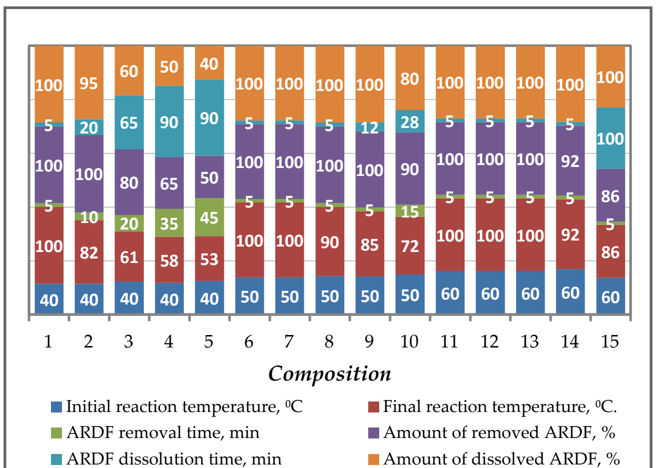

Fig. 2. Time and efficiency of removal and dissolution of ARPD

involves washing paraffin from the substrate's surface, followed by dissolution. Conversely, removal encompasses washing paraffin particles, subsequent dispersion of these particles, and extraction of oil in volume.

The emulsion was prepared within a stationary container using UPNP and KRS base. A mixture of 24% hydrochloric acid and ammonium chloride was added to the water bath and thoroughly mixed. Subsequently, sodium nitrite, neonol, and gas condensate were added to the mixture and thoroughly mixed.

The composition of the emulsion (wt.%): ammonium chloride – 7%; sodium nitrite – 7%; hydrochloric acid – 0.15%; neonol – 2%; gas condensate – 30%; water – remainder.

The average emulsion consumption per well operation amounted to 8 m^3.

The procedure for well treatment was as follows. In gas-lift wells, injection was carried out through tubing, and the initial portion of the emulsion, equivalent to the tubing's volume, was pumped with the annular valve open. Subsequently, the emulsion was injected into the formation, with water (60 °C) utilized as a displacement fluid.

For deep pumping wells, the emulsion was pumped via the annulus, and the initial portion of the composition, matching the annulus volume from the wellhead to the pump intake, was pumped while the pumping machine was operational. Following this, the composition was directed into the formation using hot water (60 °C) in a volume equivalent to the annulus volume plus the volume of the well from the pump intake to the upper holes of the perforation interval.

Subsequently, the wells were sealed and allowed to undergo a reaction period lasting from 4 to 12 hours before being put into operation. The outcomes of these treatments of the BHFZ of production wells of the Uzen field with an emulsion based on natural gasoline and ammonium nitrite are delineated in table 3.

The outcomes of treating the bottomhole zone with an emulsion based on gas gasoline and ammonium nitrite, as presented in table 3, demonstrate that this technology effectively removed ARPD from the bottomhole zone of oil wells and increased oil production in 5 out of 6 treated wells. The positive effect lasted 17-27 days, with oil inflow increasing by 17-174 %. This led to a total additional oil production of 1528 tons from the five wells.

Table 3

Results of treatment of the bottomhole formation zone of production wells of the Uzen field

No. of wells	Reservoir	Method of operation	Average parameters before processing			Average parameters after processing			Duration of effect, days	Additional oil production,%	Additional oil production, t
			Qw, t/day	Qo, t/day	%, water	Qw, t/day	Qo, t/day	%, water			
2495	XIV	SRP*	41.5	32	22.9	24.4	19	22.1	-	-40.6	-
3157	XIV	SRP	40	36	10.0	49	42	14.3	27	16.7	162
3112	XVI	SRP	31	19	38.7	72.5	52	28.3	27	173.7	891
4204	XVIII	SRP	5.3	4.1	22.6	9.4	7	25.5	17	70.7	49
5767	XVI	gas lift	74	47	36.5	153	61	60.1	27	29.8	378
1597		gas lift	53	12.7	76.0	64	15.4	75.9	18	21.3	48
											1528

**SRP – sucker rod pump*

Conclusion

The research findings can be summarized as follows:

1. The effectiveness of this technology is measured by several indicators: changes in the daily oil production rates of wells, the duration of the increased oil production period, and the changes in well productivity coefficient before and after treatment.
2. Laboratory experiments on the effectiveness of the developed composition for removing asphalt, resin, and paraffin deposits indicated that the optimal content of ammonium nitrite in an emulsion based on gas gasoline and nitrite solutions is 9-10%, with hydrochloric acid at 0.15%.
3. Based on laboratory research, an effective emulsion was developed to remove asphalt, resin, and paraffin deposits. The composition includes: ammonium chloride – 7%, sodium nitrite – 7%, hydrochloric acid – 0.15%, neonol – 2%, gas condensate – 30%, and water – the remainder. When mixed, ammonium chloride and sodium nitrite form ammonium nitrite. The density of the resulting composition is 0.932 g/cm^3.
4. Field tests on six production wells at the Uzen field showed that the developed technology effectively removed asphalt, resin, and paraffin deposits from the bottomhole zone of oil wells, resulting in increased oil production in 5 out of 6 treated wells. The positive effect lasted 17-27 days, with oil inflow increasing by 17-174 %, leading to an additional oil production of 1528 tons from the five wells.

The study was supported by the Science Committee of the Ministry of Science and Higher Education of the Republic of Kazakhstan (grant No. AP19679430).

References

1. Bai, M., Zhang, Z., Chen, Q., et al. (2021). Research on the enhanced oil recovery technique of horizontal well volume fracturing and CO_2 huff-n-puff in tight oil reservoirs. *ACS Omega*, 6(43), 28485–28495.

2. Zhao, X., Yang, Z., Liu, X., et al. (2023). Study on the flow characteristics of tight oil reservoirs with linear injection and production for volume-fractured horizontal wells. *Physics of Fluids*, 35(6), 063112.

3. Rubinstein, J. L., Mahani, A. B. (2015). Myths and facts on wastewater injection, hydraulic fracturing, enhanced oil recovery, and induced seismicity. *Seismological Research Letters*, 86(4), 1060–1067.

4. Barati, R., Liang, J. T. (2014). A review of fracturing fluid systems used for hydraulic fracturing of oil and gas wells. *Journal of Applied Polymer Science*, 131(16), 40735.

5. Yu, W., Lashgari, H. R., Wu, K., Sepehrnoori, K. (2015). CO2 injection for enhanced oil recovery in Bakken tight oil reservoirs. *Fuel*, 159, 354–363.

6. Koroviaka, Ye., Pinka, J., Tymchenko, S., et al. (2020). Elaborating a scheme for mine methane capturing while developing coal gas seams. *Mining of Mineral Deposits*, 14(3), 21–27.

7. Malik, M. A., Hashim, M. A., Nabi, F., et al. (2011). Anti-corrosion ability of surfactants: a review. *International Journal of Electrochemical Science*, 6(6), 1927–1948.

8. Al-Yaari, M. (2011). Paraffin wax deposition: mitigation & removal techniques. SPE-155412-MS. In: *SPE Saudi Arabia section Young Professionals Technical Symposium. Society of Petroleum Engineers.*

9. Suleimanov, B. A., Ismailov, F. S., Veliyev, E. F. (2011). Nanofluid for enhanced oil recovery. *Journal of Petroleum Science and Engineering*, 78(2), 431–437.

10. Suleimanov, B. A., Abbasov, H. F., Ismayilov, R. H. (2023). Enhanced oil recovery with nanofluid injection. *Petroleum Science and Technology*, 41(18), 1734–1751.

11. Efendiyev, G. M., Guliyev, H. H., Strekov, A. S., et al. (2017). Nanotechnologies and the problem of oil production intensification. In: *16th International Conference on Geoinformatics – Theoretical and Applied Aspects*, May, 1–5.

12. Suleimanov, B. A., Latifov, Y. A., Veliyev, E. F. (2019). Softened water application for enhanced oil recovery. *SOCAR Proceedings*, 1, 19–28.

13. Suleimanov, B. A., Veliyev, E. F., Naghiyeva, N. V. (2020). Preformed particle gels for enhanced oil recovery. *International Journal of Modern Physics B*, 34(28), 2050260.

14. Veliyev, E. F., Askerov, V. M., Aliyev, A. A. (2022). Enhanced oil recovery method for highly viscous oil reservoirs based on in-situ modification of physico-chemical properties. *SOCAR Proceedings*, SI2, 144–152.

15. Suleimanov, B. A., Veliyev, E. F. Naghiyeva, N. V. (2021). Colloidal dispersion gels for in-depth permeability modification. *Modern Physics Letters B*, 35(1), 2150038.

16. Borash, B. R., Biletskiy, M. T., Khomenko, V. L., et al. (2023). Optimization of technological parameters of airlift operation when drilling water wells. *Naukovyi Visnyk Natsionalnoho Hirnychoho Universytetu*, 3, 25–31.

17. Belsky, A. A., Dobush, V. S., Morenov, V. A., Sandyga, M. S. (2018). The use of a wind-driven power unit for supplying the heating cable assembly of an oil well, complicated by the formation of asphalt-resin-paraffin deposits. *Journal of Physics: Conference Series*, 1111, 012052.

18. Bissengaliev, M., Bayamirova, R., Togasheva, A., et al. (2022). Analysis of complications associated with the paraffinization of borehole equipment and measures to prevent them. *News of the National Academy of Sciences of the Republic of Kazakhstan. Series of Geology and Technical Sciences*, 3(453), 76–88.

19. El-Dalatony, M., Jeon, B. H., Salama, E. S., et al. (2019). Occurrence and characterization of paraffin wax formed in developing wells and pipelines. *Energies*, 12(6), 967.

20. Togasheva, A., Bayamirova, R., Sarbopeyeva, M., et al. (2024). Measures to prevent and combat complications in the operation of high-viscosity oils of Western Kazakhstan. *News of the National Academy of Sciences of the Republic of Kazakhstan. Series of Geology and Technical Sciences*, 1(463), 257–270.

21. Chi, Y., Daraboina, N., Sarica, C. (2017). Effect of the flow field on the wax deposition and performance of wax inhibitors: cold finger and flow loop testing. *Energy & Fuels*, 31(5), 4915–4924.

22. Borash, A. R., Nurshakhanova, L. K., Arshidinova, M. T., et al. (2023). Improving the efficiency of PDC bits in oil and gas drilling. In: *SGEM International Multidisciplinary Scientific GeoConference EXPO Proceedings.*

23. Ratov, B., Borash, A., Biletskiy, M., et al. (2023). Identifying the operating features of a device for creating implosion impact on the water bearing formation. *Eastern-European Journal of Enterprise Technologies*, 5(1(125)), 35–44.

24. Wang, W., Huang, Q. (2014). Prediction for wax deposition in oil pipelines validated by field pigging. *Journal of the Energy Institute*, 87(3), 196–207.

25. Souas, F., Safri, A., Benmounah, A. (2020). A review on the rheology of heavy crude oil for pipeline transportation. *Petroleum Research*, 6(2), 116–136.

26. Rehan, M., Nizami, A.-S., Taylan, O., et al. (2016). Determination of wax content in crude oil. *Petroleum Science and Technology*, 34(9), 799–804.

27. Bayamirova, R., Togasheva, A., Zholbassarova, A., et al. (2020). Selection of effective demulsifying agents for oil-water emulsions breakdown. *Studia Universitatis Babeș-Bolyai Chemia*, 65(4), 53–61.

28. Ratov, B. T., Chudik, I. A., Fedorov, B. V., et al. (2023). Results of production tests of an experimental diamond crown during exploratory drilling in Kazakhstan. *SOCAR Proceedings*, 2, 025–031.

29. Wenda, W., Qiyu, H., Jun, H., et al. (2014). Study of paraffin wax deposition in seasonally pigged pipelines. *Chemistry and Technology of Fuels and Oils*, 50(1), 39–50.

30. Ihnatov, A. O., Haddad, J., Stavychnyi, Ye. M., Plytus, M. M. (2023). Development and implementation of innovative approaches to fixing wells in difficult conditions. *Journal of the Institution of Engineers (India): Series D*, 104, 119-130.

31. Ismailova, J., Abdukarimov, A., Delikesheva, D., et al. (2023). Application of fusion property estimation within the multisolid wax prediction model on Kazakhstani crude. *Heat Transfer*, 53(2), 533–557.

32. Wang, R., Du, T., Cao, J., Wang, G. (2024). The paraffin crystallization in emulsified waxy crude oil by dissipative particle dynamics. *Frontiers in Heat and Mass Transfer*, 22(1), 1–10.

33. Koilybayev, B. N., Karazhanova, M. K., Efendiyev, G. M., et al. (2022). Analysis and assessment of accuracy of the oil recovery factor calculations by using the fuzzy clustering algorithm. In: *11th International Conference on Theory and Application of Soft Computing, Computing with Words and Perceptions and Artificial Intelligence – ICSCCW-2021. Lecture Notes in Networks and Systems, Springer, Cham.*

34. Suleimanov, B. A., Veliyev, E. F. (2017). Novel polymeric nanogel as diversion agent for enhanced oil recovery. *Petroleum Science and Technology*, 35(4), 319-326.

35. Mcelfresh, P. M., Olguin, C., Ector, D. (2012). The application of nanoparticle dispersions to remove paraffin and polymer filter cake damage. SPE-151848-MS. In: *SPE International Symposium and Exhibition on Formation Damage Control. Society of Petroleum Engineers.*

36. Wang, H. (2019). A non-isothermal wellbore model for high pressure high temperature natural gas reservoirs and its application in mitigating wax deposition. *Journal of Natural Gas Science and Engineering*, 72, 103016.

37. Xu, X., Bao, T. (2020). Research on the removal of near-well blockage caused by asphaltene deposition using sonochemical method. *Ultrasonics Sonochemistry*, 64, 104918–104918.

38. Vishnyakov, V., Suleimanov, B., Salmanov, A., Zeynalov, E. (2019). Primer on enhanced oil recovery. *Gulf Professional Publishing*.

39. Suleimanov, B. A., Veliyev, E. F., Vishnyakov, V. (2022). Nanocolloids for petroleum engineering. *John Wiley & Sons.*

40. Rashid, Z., Wilfred, C. D., Gnanasundaram, N., et al. (2019). A comprehensive review on the recent advances on the petroleum asphaltene aggregation. *Journal of Petroleum Science and Engineering*, 176, 249–268.

41. Akhmetov, D. A., Efendiyev, G. M., Karazhanova, M. K., Koylibaev, B. N. (2019). Classification of hard-to-recover hydrocarbon reserves of Kazakhstan with the use of fuzzy cluster-analysis. In: *13th International Conference on Theory and Application of Fuzzy Systems and Soft Computing – ICAFS-2018. Advances in Intelligent Systems and Computing, Springer, Cham.*

42. Tiwari, S., Verma, S. K., Karthik, R., et al. (2014). In-situ heat generation for near wellbore asphaltene and wax remediation. IPTC-17681-MS. In: *IPTC 2014: International Petroleum Technology Conference, Doha, Qatar.*

43. Lim, Z. H., Al Salim, H. S., Ridzuan, N., et al. (2018). Effect of surfactants and their blend with silica nanoparticles on wax deposition in a Malaysian crude oil. *Petroleum Science*, 15(3), 577–590.

44. Suleimanov, B. A., Suleymanov, A. A., Abbasov, E. M., Baspayev, E. T. (2018). A mechanism for generating the gas slippage effect near the dewpoint pressure in a porous media gas condensate flow. *Journal of Natural Gas Science and Engineering*, 53, 237–248.

45. Togasheva, A. R., Bayamirova, R. Y., Zholbassarova, A. T., et al. (2023). Pilot field tests of shock-wave treatment of wells at the fields of JSC "OZENMUNAIGAS." In: *SGEM International Multidisciplinary Scientific GeoConference EXPO Proceedings.*

46. Biletskiy, M. T., Ratov, B. T., Khomenko, V. L., et al. (2022). Increasing the Mangystau peninsula underground water reserves utilization coefficient by establishing the most effective method of drilling water supply wells. *News of the National Academy of Sciences of the Republic of Kazakhstan. Series of Geology and Technical Sciences*, 5(455), 51–62.

47. Khomenko, V. L., Ratov, B. T., Pashchenko, O. A., et al. (2023). Justification of drilling parameters of a typical well in the conditions of the Samskoye field. *IOP Conference Series: Earth and Environmental Science*, 1254(1), 012052.

48. Biletskiy, M. T., Ratov, B. T., Khomenko, V. L., et al. (2024). The choice of optimal methods for the development of water wells in the conditions of the Tonirekshin field (Kazakhstan). *Naukovyi Visnyk Natsionalnoho Hirnychoho Universytetu*, 1, 13–19.

49. Salmanov, A. M., Ahmadov, E. H., Rahimov, F. V. (2019). Geological assessment of reservoir factors of the Umid-Babek area. *SOCAR Proceedings*, 3, 8–14.

50. Efendiyev, G. M., Kuliyev, R. H., Karazhanova, M. K., et al. (2021). Decision-making in the production of hard-to-recover oil reserves under uncertainty. In: *11th World Conference «Intelligent System for Industrial Automation» (WCIS-2020). Advances in Intelligent Systems and Computing, Springer, Cham.*