

Review

Overview of Methods for Enhanced Oil Recovery from Conventional and Unconventional Reservoirs

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Abstract: In world practice, the role of reproduction of raw material base of oil production by implementing modern methods of oil recovery enhancement (thermal, gas, chemical, microbiological) on the basis of innovative techniques and technologies is rapidly growing and is becoming more important. It is concluded that at present, the priority of increasing oil reserves in world oil production is the development and industrial introduction of modern integrated methods of enhanced oil recovery, which can provide a synergistic effect in the development of new and developed oil fields. This article presents a review and comparative analysis of theoretical and practical methods of improving oil recovery of conventional and unconventional reservoirs. The paper examines in detail methods of improving oil recovery, taking into account the factors of enhanced oil recovery of oil reservoirs. Considered the main methods and technologies currently used to develop oil fields and recommendations for their effective use, taking into account the variety of external factors of oil production: the geological structure of the reservoir, its volume, and properties of oils. It is shown that there is no universal method of oil reservoir development, and it must be chosen after a thorough feasibility study among several proposed models. When describing the methods of enhanced oil recovery, special attention is also paid to the physical processes that occur as a result of applying the technology. In conclusion, the positive and negative characteristics of the presented methods included in EOR are presented, and recommendations that may influence the choice of practical solutions for engineers and oil producers are given. Conclusions are made that development systems, placement and choice of operating mode of wells essentially depend on the geological structure of the reservoir, its volume and properties of oils. An important role in this is the construction of a geological model of the production facility. The used hydrodynamic models of development are based on physical laws, about which oil producers sometimes don't even suspect, and the authors of the models are not always able to convey it to the real producers. The authors consider it reasonable to make a logical generalizing conclusion that understanding processes occurring in the reservoir

and taking appropriate measures for optimization and intensification of oil production will allow making oil production as effective as possible.

Keywords: EOR; oil reservoir; oil stimulation method; enhanced oil recovery method

1. Introduction

Since the 60s of the last centuries, issues related to the use of physico-chemical methods of enhanced oil recovery (PH EOR) in the development of oil fields have been of interest to oil specialists [1]. The structure of the reserves of developed deposits is changing; new fields with a more complex geological structure are being discovered, and new, more efficient technologies for developing oil fields are being introduced, but interest in reservoir stimulation technologies based on the use of various chemical compositions remains. This is due to the need to search for technical solutions “for tomorrow”, when drilling wells and regulating their operating modes, the introduction of new design approaches and optimization of the field development system as a whole will not be able to provide the required level of production and depletion of oil reserves [2]. Despite the large accumulated experimental and practical experience in the application of enhanced oil recovery methods, at present, there is a large gap between the needs of oilfield workers and the market supply of services for the implementation of these methods. The problem is also complicated by a significant reduction in the reagent base for PH EOR and, most importantly, the lack of a well-developed methodology for the use of certain compositions. When addressing these issues within the framework of the tender system for the provision of services, oil-producing enterprises are often guided by the accumulated practical experience in this area without the development and adaptation of new technologies.

Now, when almost all the world’s largest fields are at the advanced stages of development, a comprehensive study of the accumulated field experience in the implementation of PH-CH EOR and a reasonable classification of such methods are required to develop strategic approaches to their application and identify the most effective solutions for influencing certain groups of oil reservoirs [3]. In this paper, based on the analysis of information sources on the practical use of physico-chemical methods of enhanced oil recovery in recent years, as well as the experience of the authors, a classification of such methods is proposed. It takes into account different approaches, including the component composition of injected solutions (mixtures) and the direction of their action in relation to the reservoir and reservoir fluids [4].

This classification is largely based on the group division of generally accepted technical approaches using the terminology that has been developed in the industry, which, in fact, objectively reflects the chemical nature of the reagents used and the products of their interaction [5]. The authors do not claim the exclusivity and universality of the designated classification and the method of separation of technologies, but in the chosen format, there are specialists who consider a rational option for a single designation of various types of PH-CH EOR, showing their opinion on the directions and prospects for their use and further development [6]. When considering information sources, in most cases, the terminology and designations adopted by the authors of the original works were used.

In many old fields, the pressure filtration capabilities have almost exhausted their resource of possibilities. Further work on these deposits becomes economically unfeasible. Until now, this has been solved by increasing the price of oil and burning working capital from consumers of oil products. This, in turn, led to a crisis. The problem of extracting the maximum amount of geological reserves available in the reservoirs from oil-bearing reservoirs at acceptable costs, providing at least some profitability, is becoming urgent. The value of recoverable reserves varies widely (from 7–12% to 30–40%) and is determined not only by the geological conditions of the deposit but also by the technological method of field development, which provides certain values of oil recovery factors available for this

method. These values of the development of geological reserves are the limits of traditional methods of development. Until recently, it was believed that the extraction of residual oil was impossible at all due to its immobility in the reservoir and the lack of technologies for extraction, which was true. Therefore, in world practice, huge reserves (from 50 to 90%) of hydrocarbon raw materials remain inaccessible for development and have not been fully developed [7]. The implementation of projects for deeper development of geological reserves requires novelty, and high technological and economic efficiency, which consists of a fundamental change not only in the traditional approach to the development of oil-saturated reservoirs but also in the laws of filtration. The laws of hydraulics are far from the natural laws of oil filtration in the reservoir. This has been established by research experience [8]. The traditional method of development is based on the laws of macro-hydrodynamics, where the decisive role is played by the viscosity of the fluids and the geometry of the pore channels of the reservoir rock. Traditional technologies have exhausted their resources and are not able to solve the problem of extracting hard-to-recover reserves, even theoretically. The creation of new technologies is based on new, deep fundamental knowledge, which radically changes the idea of an oil reservoir. The collector is a complex energy system, where not only physical forces play a decisive role but also the forces of intermolecular and interatomic interactions, as well as the energies of dynamic processes of fluid movement. Additionally, these are already elements of nano-technologies that provide a qualitative leap in the level of knowledge and the efficiency of their use. New science-intensive technologies for the development of oil and gas fields are based on the complete theory of filtration. Such criteria are met by technologies of electrophysical impact on oil reservoirs, allowing not only increasing the productivity of wells and extracting residual oil from depleted structures to produce the synthesis of the necessary chemical compounds. Contributing to the complete extraction of hydrocarbons and associated rare earth elements, the authors show that their cost can exceed the cost of oil by dozens of times. In this case, it shows where the solution to oil recovery problems is at a new level of knowledge. The technology of electrophysical impact can be considered as a natural and necessary improvement in the technology of developing oil and gas fields as a technique for using the general sensitivity of the rocks of an oil reservoir to electrical energy. They are modulated and configured to use certain given physical, chemical and dynamic characteristics of the oil-bearing reservoir and the fluids in it to regulate and control the processes occurring in the oil-bearing formation to intensify the inflow and increase oil recovery. Along with the impact of electrical energy on the oil reservoir, it has a wide range of manifestations, both positive and negative. Without knowing them, it is impossible to obtain the desired result. With the availability of appropriate techniques and correctly established modes of action, it is possible to obtain the desired technological effects for intensifying production, controlling filtration flows in the reservoir, and increasing oil recovery. In this way, the oil recovery factor can be multiplied. For hard-to-recover oils, the value of which is low, several times, it allows extending the terms of a profitable development of oil fields, reducing the cost of oil production. These include relatively small additional capital investments, in comparison with other methods of increasing oil recovery, by which it is simply impossible to achieve such values. The implementation of technological solutions requires the appropriate qualifications of specialists and maintenance personnel and additional capital investments for the development and maintenance of equipment and wells. Today, this is the main method that allows you to extract residual oil, acceptable in technical, technological and economic terms [9], providing reducing the cost of oil production and obtaining additional oil production at the expense of the non-recoverable part of geological reserves. This increases the resource base of oil-producing companies at least two times. Increasing the terms of profitable field development, increasing the number of jobs in the “old” oil-producing areas with the developed infrastructure, and protecting the environment in the development area. Considering the fact that the actual reserves of hydrocarbons on Earth are limited and exhausted as they are consumed, the possibility of obtaining additional residual oil from depleted structures can postpone the time of the energy oil collapse. The

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Speaking about the importance of enhanced oil recovery and the current state of hydrocarbon development in different countries and large oil and gas fields, the use of additional EOR methods should be highlighted. Tertiary enhanced oil recovery (EOR) methods are enhanced oil recovery methods using complex technologies that change the original properties of reservoir fluids. They are used at the final stage of development but, in fact, can be applied at any time during the life of the field.

There are three most commonly used types of tertiary EOR: chemical, thermal and gas. The optimal application of each type depends on many factors: reservoir temperature, pressure, depth, permeability, residual oil and water saturation, porosity and properties of the formation fluids, such as density, viscosity and salinity.

Tertiary enhanced oil recovery (EOR) methods are more science-intensive and technologically complex than conventional EOR methods. When producing oil, energy must be expended to lift the crude oil from the deposit to the surface. At the beginning of field development, the natural reservoir pressure provides most of this energy, but then it decreases, and additional equipment must be used. The reservoir pressure can be increased by injecting water or gas to displace additional volumes of oil. However, even after applying these methods, a significant amount of oil remains in the reservoir. In this case, it becomes reasonable to use tertiary EOR methods; these include chemical methods, thermal methods and gas methods.

Tertiary EOR methods are becoming widespread in the world, which is due to the active extensive development of the industry and the reorientation of market players to shale projects, which are much faster profitable. Nevertheless, as the resource base for many countries, including Russia, depletes and becomes more complex, the use and improvement of these production methods will prolong the life of deposits in traditional production regions, where all the infrastructure is already in place, exploration has been conducted, and only additional field exploration activities are required, which means that companies will need to spend fewer resources compared to new projects, where all the infrastructure must be created from scratch, moreover, it will cause less harm to the environment.

The application of tertiary methods of oil recovery could also have a positive impact on the economy of traditional oil production regions. It will require the development of new technologies, creating a new market for oil service companies and prolonging the economic and tax life of fields.

If we talk about the methods of CO₂ injection methods, their undeniable advantages for companies are:

- Production of oil with a low carbon footprint. Reduction of CO₂ emissions using CO₂ capture technologies, which is one of the highest priorities of the modern global climate agenda;
- Development of new technologies in demand. Since technology capture and storage of CO₂ only develop, oil and gas companies have a huge competitive advantage in this niche because they have on hand as a source of CO₂ emissions and collectors, which can pump this CO₂. That is, in fact, oil companies can create a new niche for themselves in the market.

There are four stages of field development: the first three stages are the main development period, and the fourth is the final stage. In the first stage, oil is produced through natural processes (pressure in the reservoir). The oil recovery factor (ORF) does not exceed 15%. After some time, the reservoirs lose their energy, and the field passes to the second stage.

The second stage is characterized by compensation and artificial maintenance of reservoir pressure by injecting working agents in the form of water (flooding) or gas, which allows for maintaining production levels or even growth. The ORF at this stage reaches a

maximum of 30%. The first two stages together provide an oil recovery factor at the level of 25–30%.

Tertiary EOR methods are implemented at the third stage in the case of a mature development system when conventional geological and engineering operations can no longer ensure the maintenance of production levels. Tertiary EOR allows achieving ORF of 40–70%; their application significantly increases oil recovery in non-prospective mature fields. At the same time, the world average ORF is 35%.

Application of tertiary EOR changes the physical properties of hydrocarbons and formation water, which cardinally distinguishes this phase of production from the initial stages. Water floods displace oil by the injection front to the production wells, whereas tertiary EOR methods often use steam or gas to change oil viscosity.

The main advantage of tertiary EOR is the opportunity to increase the oil recovery factor at existing fields. The world ORF varies between 30–35%. In Russia, it is, on average equal to the global level, much depends on the oil-producing region (Figure 1, <https://www.equinor.com/en/how-and-why/increasing-valuecreation.html>, accessed on 1 March 2023). At the same time, in some countries, such as Norway and Saudi Arabia, the ORF averages 50–57%, respectively.

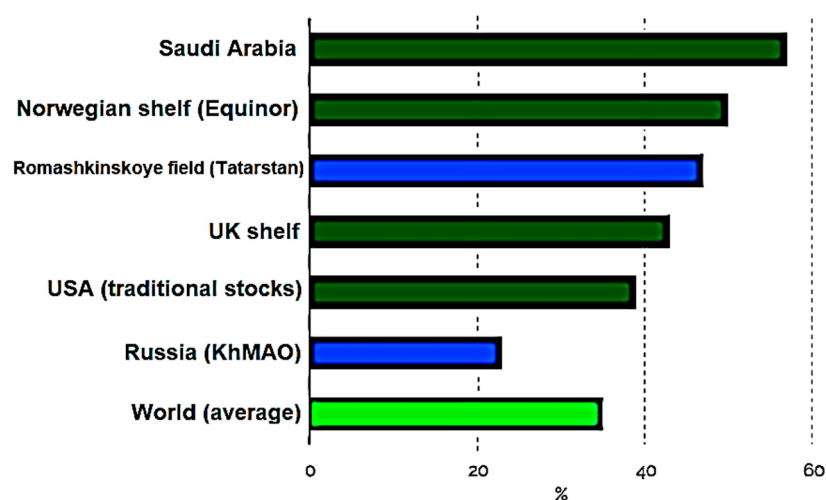


Figure 1. Average ORF by country of the world [9].

Therefore, even a small increase in it will make it possible to significantly increase the resource base without significant investments in the exploration and development of new projects. Thus, according to calculations of Shell, the growth of an oil recovery factor of only 1% in the world will increase the conventional oil reserves to 88 billion barrels, which is 2.5 times more than today is produced per year.

In the geological literature devoted to oil subjects, there are different understandings and interpretations of the term “natural reservoir”. The structure of natural reservoirs is determined by their type, the material composition of their constituent rocks, the type of void space of reservoir rocks and the aging of these rocks over the area. There are several types of natural reservoirs, five of which are basic:

1. Formation;
2. Lithologically confined;
3. Hydrodynamically open;
4. Catagenetic;
5. Massive;
 - 5.1. Carbonate massifs;
 - 5.2. Terrigenous strata-massive.

All the strata composing the body of the massif are usually hydrodynamically connected but may be of different ages. The fluid reservoirs are strata or strata of rock salt, clay

or sulfate rocks. Such a natural reservoir encompasses several tiers and may stand out in the volume of the entire formation.

The nature of the distribution of secondary minerals, their associations, and the number can be studied using traditional petrographic methods, including quantitative mineralogical counting of new formations in thin sections; the most typical features of minerals, their interchange and mineral associations either increase or decrease. Some clays are as highly porous as sandstones, but they are impermeable because their pore size is very small. The larger the pores, the higher the permeability. In general, there is no direct relationship between porosity and permeability, although rocks with low porosity (10–15%) usually have low permeability as well. If the permeability is low, oil will only ooze weakly from the rock and productivity will be less than economically viable. Therefore, it is difficult to recover oil from clays, although abundant signs of oil in them are found in many areas of the world.

Methods for recovering oil from clayey rocks are being developed. Prediction of changes in the reservoir properties of rocks during their subsequent burial can be made by statistical methods based on the study of physical and chemical processes that took place or on the results of quantitative petrographic studies, and each method has its limitations. The thickness of sand bodies, their area development and shape in plan, internal structure and nature of contacts with the surrounding strata are laid down by the sedimentation environment, which predetermines the reservoir volume and the well placement technique. At present, the problem of selecting rational good placement systems for prospecting non-anticlinal reservoirs is not fully solved due to the absence, as a rule, of reliable methods for identifying traps of this type. Most lithologically screened and lithologically confined deposits are discovered incidentally when searching and exploring for deposits in anticlinal traps, i.e., using well placement systems.

The shape (morphology) of a natural reservoir is determined by the ratio of reservoir rocks and cover rocks in the section and over the area. Variability of the productive formation shape is determined by its unequal thickness (total and effective), dissection, wedging of the whole formation and its constituent interlayers, and their lithological and facial replacement by impermeable differences. Formation natural reservoirs are reservoir beds bounded on a large territory at the top and bottom by impermeable rocks (fluids). Their thickness varies within a significant range (from 1–2 m to tens of m). In the lithological plan, they can be represented by both terrigenous and carbonate rocks; they may contain interlayers and interlayers of impermeable rocks in the reservoir bed. Formation natural reservoirs with lithologically wedging reservoirs are widely developed in the sediments of many geological systems. Reservoir wedging can occur in the case of monoclinical bedding of sedimentary formations in the direction of rock uplift.

The purpose of this paper is:

1. To expand the conceptual and categorical apparatus related to the predictive evaluation of the results of measures to increase oil recovery and to form a comprehensive methodological approach to the planning of these activities;
2. To propose the use of combined activities to enhance oil recovery, maximizing the volume of additional oil production.

The practical significance of the developed proposals is that they form the basis for practically acceptable tools to assess methods of increasing oil recovery in the late stages of field development. In particular, the proposed approaches allow choosing the most effective ones for oil and gas producing companies: in conditions of significant variation of geological and field parameters, increasing the possibility of forecasting the increase in oil production due to methods of oil recovery enhancement, thereby reducing the cost of oil production with an acceptable level of risk.

The emphasis in this work is placed both on the theoretical aspects of the application of enhanced oil recovery technologies and on the practical application of theirs.

2. Conventional and Unconventional Reservoirs

It is important to note that the distinction between traditional and non-traditional hydrocarbon resources is conditional in terms of a number of parameters. It is necessary to understand what sources of hydrocarbons create traditional and unconventional hydrocarbon deposits. A detailed consideration of the geological patterns of the formation of hydrocarbon accumulations shows that an understanding of these processes helps in the search for hydrocarbons (HC), assessing the number of hydrocarbons in deposits and methods for their extraction. Let us take traditional oil source strata. If these strata gave their hydrocarbon potential to the reservoir with a tire, then an oil and gas field or a traditional hydrocarbon field was formed. At the same time, the deposit of unconventional shale gas disappeared. Accordingly, the presence of residual hydrocarbons in shale makes it possible to extract them using modern methods, calling them an unconventional source of hydrocarbons. In addition, there is an inflow of hydrogen and hydrocarbon gases from deep horizons of the earth's crust and mantle. This flow can create both traditional and unconventional deposits. Non-traditional sources of hydrocarbons allow listing non-traditional sources of hydrocarbons. These are gas hydrates, coal methane, shale gas, tight reservoirs, and biogas. Let us add one more thing: coal-shale gas (the name given to us) as a kind of shale gas. Let us characterize these sources and show their relationship with traditional hydrocarbon sources, gas hydrates. This ice-like solid is formed when hydrocarbons are introduced into the space between water molecules at high pressure and low temperature. For example, at a pressure of 30 atm and a temperature of 0 °C, in the presence of water and hydrocarbon gases, mainly methane, gas hydrates are formed in bottom sediments. As the temperature increases, a higher pressure is required to form gas hydrates. For example, in the Sea of Okhotsk, at a bottom water temperature of +2.4 °C, gas hydrates were found at a minimum depth of 386 m. At a shallower depth at this temperature, gas hydrate cannot be formed due to insufficient pressure. The gas hydrate, which contains mainly methane, is characterized by structure I and II. If hydrocarbons with a large size of propane molecules are present in the gas hydrate, structure II is formed. Why are gas hydrates of interest? They are an important object of geological research. In bottom sediments in the zone of stability of gas hydrates, the latter occurs in the form of layers, interlayers, and fragments. 1 cm³ of gas hydrate contains 170 cm³ of gas (hydrocarbons, methane). Gas hydrate plays a very important role in the geological history of the Earth and the formation of oil and gas deposits. The gas hydrate preserves hydrocarbons that migrate to the surface from oil and gas deposits, mantle and other sources. In a gas hydrate, hydrocarbon gases are not subject to microbial oxidation. The gas hydrate loosens the bottom sediments, penetrating into them, changing the bottom surface topography, and forming rises and dips in the upper layers of the bottom sediments, which is important to know when solving engineering geological problems and building offshore facilities. An important geological feature of gas hydrates is their impermeability. They are a good tire under which free gases accumulate. During periods of seismotectonic activations, this seal is disturbed by fault zones, through which gas (methane, heavy hydrocarbons) moves through the layers of the sedimentary stratum, partially filling the reservoir, forming deposits, and partially migrating in the form of a flow of bubbles into the water column. At the same time, the concentration of methane in water increases 100–1000 times and partially enters the atmosphere, which contributes to global climate change (warming). The formation of oil and gas deposits is interconnected with gas hydrates [8]. In the geological history of the Earth, there were periods of cooling and warming; the levels of the seas and oceans changed, which means that pressure and temperature were disturbed (the gas hydrate stability zone changed), and the gas hydrate contributed to the formation of hydrocarbon deposits. The second side of the importance of studying gas hydrates is that gas hydrates contain trillions of cubic meters of hydrocarbons that can be extracted as unconventional deposits. Currently, the extraction of hydrocarbons from gas hydrates, which are found in bottom sediments in the upper layers at a bottom depth of 1–10 m, has not yet reached commercial efficiency. The authors proposed one of the methods [9]. The difficulty lies in the fact that gas hydrates are mainly distributed in

the bottom sediments of the seas, where it is difficult to extract hydrocarbons. However, it is important that gas hydrates are an indicator of the presence of hydrocarbons at depth; that is, they search for signs of oil and gas deposits. Traditional and unconventional hydrocarbon resources, gas hydrates and oil and gas deposits are gas hydrates that are found in the form of reservoirs in wells developed by conventional methods of operating oil and gas wells, with heating, pressure reduction and other methods.

Thus, it is necessary to understand in more detail what traditional and non-traditional sources of hydrocarbon production represent. It is not just about terminology. It must be understood that this is the same source of hydrocarbons. It is important to proceed from the history of the geological development of the studied region and basin in order to correctly assess the conditions for the formation of traditional and unconventional hydrocarbon deposits, the flow of hydrocarbons from the mantle, from the organic matter of shale, their mutual influence and accumulation in traditional reservoirs. All types of unconventional hydrocarbon sources: oil, gas hydrates, coal gas, coal gas shale gas, shale oil, biogas and tight reservoir gas, are all interconnected and create traditional oil and gas fields.

For a general understanding of the problem of enhanced oil recovery from traditional and unconventional reservoirs, it is necessary to compare the similarities and highlight the differences between traditional and unconventional oil production reservoirs. In the oil industry, reservoirs include rocks that can contain fluids and release them under pressure drop (with modern technologies). Reservoirs are characterized by filtration and capacitive properties of the formation (FES). Speaking of reservoirs, one should distinguish between reservoir rocks and their properties. Reservoir rocks have the ability to contain oil, gas, and water and release them during development. The vast majority of reservoir rocks are of sedimentary origin. Oil and gas reservoirs are both terrigenous (sands, silts, sandstones, siltstones and some clayey rocks) and carbonate (limestone, chalk, dolomite) rocks. Unconventional reservoirs are volcanogenic, metamorphic, igneous and intrusive rocks (White Tiger). Porosity is the volume of the pore space, which is estimated by the ratio of the pore volume to the rock volume. Expressed as a percentage, this value is called the porosity coefficient. Some pores communicate with each other. Such porosity is called open. A porosity in which the pore channels are large enough (>0.2 mm) to allow fluids to pass relatively freely through them and be relatively easily (economically) extracted is called effective porosity. It should be noted that there are also such concepts as heterogeneity and anisotropy of reservoirs [7].

Oil fields, as objects of nature, have a variety of properties. Oil can be found in sandstones, siltstones with intergranular porosity, as well as in limestones, dolomites, clay rocks with microcracks and caverns. The difference in reservoir properties in certain sections of the reservoir is correlated with lithological heterogeneity. The presence of fractures and lithological heterogeneity of reservoir rocks has a significant impact on the processes of oil and gas recovery [8].

3. Enhanced Oil Recovery Methods Used for Intensification of Oil Production

3.1. Structure and Main Destination of Methods for Enhanced Oil Recovery (EOR)

In order to increase the economic efficiency of field development, reduce direct capital investments and maximize the use of reinvestment, the entire period of field development is usually divided into three main stages. In the first stage, the natural energy of the reservoir is used as much as possible for oil production (elastic energy, energy of dissolved gas, energy of marginal waters, gas cap, potential energy of gravitational forces). In the second stage, methods of maintaining reservoir pressure are implemented by pumping water or gas. These methods are called secondary. In the third stage, enhanced oil recovery methods (EOR) are used to improve the efficiency of field development. Five main groups can be distinguished among them:

1. Physical and chemical methods involve flooding with the use of active impurities (surfactants, polymers, alkalis, sulfuric acid, carbon dioxide, and micellar solutions);

2. Hydrodynamic methods allow intensifying the current oil production, increasing the degree of oil recovery, as well as reducing the volume of water pumped through the reservoirs and the current water cut of the produced fluid. For example, there is cyclic flooding, changing the direction of seepage flows, and forced fluid withdrawal;
3. Gas and water–gas methods are based on the injection of air into the reservoir and its transformation into effective displacing agents due to low-temperature in situ oxidation processes. As a result of low-temperature oxidation, a highly effective gas agent is produced directly in the reservoir, containing nitrogen, carbon dioxide and NGLs (broad fractions of light hydrocarbons). For example, these are water–gas cyclic impact and displacement of oil by high-pressure gas;
4. Thermal methods are used to stimulate the flow of oil and increase the productivity of production wells based on an artificial increase in temperature in their wellbore and bottom hole zone. Thermal EOR is used mainly in the production of high-viscosity paraffinic and resinous oils. Heating leads to oil liquefaction, melting the paraffin and resinous substances that have settled during the operation of wells on the walls, lifting pipes and in the bottom hole zone. For example, they include steam-cycling treatment, in situ combustion, use of water as a thermal solvent for oil;
5. Combined technologies represent a combination of the first four components.

According to their properties, the methods of enhanced oil recovery can be divided into groups: the first one increases the coefficient of oil displacement by water; the second one increases the sweep efficiency of the reservoir by flooding, and the third group increases both coefficients and hence the oil recovery factor as a whole.

Unlike MIP, enhanced oil recovery methods affect the development object or its part, thereby allowing the involvement in the development of residual, unrecovered oil reserves that cannot be produced with the designed waterflooding system. The practice has shown that the use of EOR is several times more expensive than conventional flooding, so the profitability of their use depends on the cost of the oil produced. EOR includes [10]:

- physico-chemical methods using aqueous solutions: active impurities (surfactants (surfactants), polymers, micellar solutions, alkalis, acids), change or alignment of injectivity profiles (VPP);
- hydrodynamic methods, including cyclic flooding, changing the direction of filtration flows, creating high injection pressures, forced fluid withdrawal (FOL), combined non-stationary flooding;
- gas methods realizing the displacement of oil by high-pressure gas, water–gas treatment;
- thermal methods using the displacement of oil by heat carriers (hot water, steam), in situ combustion;
- other methods involve compaction of the good pattern, transition from one development system to another (local, selective flooding, creation of a block-closed system), hydraulic fracturing (HF), placement and operation of side and horizontal wells, microbiological, wave, and electromagnetic methods.

Enhanced oil recovery methods are based on the following changes in the physical characteristics and conditions of oil in the reservoir:

- reduction of interfacial tension at the boundary of the oil-displacing agent;
- decrease in the mobility ratio of the displaced and displacing fluids (due to a decrease in oil viscosity or a decrease in the mobility of the displacing agent);
- redistribution of oil, water and gas in the reservoir in order to consolidate oil reserves.

3.1.1. Forms of Existence of Residual Oil in the Reservoir

When developing oil fields in various ways, zones remain in the reservoirs in which residual mobile oil reserves are stored. The extraction of such reserves from developed deposits is a necessary condition for increasing oil recovery and contributes to the achievement of design development indicators [9].

According to expert estimates, the remaining oil reserves (100%) are quantitatively distributed as follows [10]:

1. Oil remaining in low-permeability interlayers (interlayers) and areas not covered by water is 27%;
2. Oil in stagnant zones of homogeneous reservoirs is 19%;
3. Oil remaining in lenses and at impenetrable screens not penetrated by wells is 24%;
4. Capillary-retained and film oil is 30%.

Residual oil (1)–(3), which is not covered by the flooding process due to the high macroheterogeneity of the developed reservoirs and stagnant zones formed by fluid flows in the reservoirs, is 70% of all residual reserves. It represents the main reserve for enhanced oil recovery. It is possible to increase the oil recovery of the reservoir due to this residual part of the oil because of improving existing systems and development technologies, as well as with hydrodynamic methods for increasing oil recovery from reservoirs.

The rest of (4) remains in flooded reservoirs due to their micro-heterogeneity and can be recovered due to exposure to various physical and physico-chemical methods.

The composition of the residual oil in the reservoir. The change in the properties of oil during the development process can occur both in the direction of weighting and in the direction of reducing the density of the produced oil. Oil weighting is associated with a decrease in reservoir pressure during development and the loss of light oil fractions during degassing, as well as oil oxidation when interacting with injected water due to the gravitational movement of weighted oils deep into the deposit. Lighter oils may remain in the upper parts of the anticlinal folds. The properties of the oil can change within small areas of the same reservoir [11].

Forces holding residual oil. The presence of residual oil reserves due to the macro-heterogeneity of the formations is due to the low oil filtration rate in low-permeability zones, layers, interlayers and lenses. Additionally, this is largely caused by pollution and clogging of the bottom hole formation zones during drilling and water injection [12]. The forces acting in a reservoir saturated with two or more mobile phases are subdivided into viscous, surface, gravitational, and elastic forces. Surface or capillary forces create a pressure of the order of 0.01–0.3 MPa at the interface between liquid phases. The magnitude of the surface forces is determined by the wettability of the rock and the microheterogeneity of the porous medium, the size of the pore channels.

Viscous forces (hydrodynamic drag) are proportional to oil viscosity. Having high dynamic viscosity coefficients, critical pressure gradients or an initial pressure gradient appear in the reservoirs, preventing oil filtration [13]. Gravitational forces create a constantly operating pressure gradient numerically equal to the difference in the densities of oil, gas and water. The value of this gradient can be 0.1–10 MPa/m. As a result, oil or gas in oil floats in water. Elastic forces arise because of a change in the stress–strain state of the reservoir due to a decrease in reservoir pressure; they cause blockage of pore channels, reduce microcracks and, therefore, contribute to the appearance of residual oil saturation.

Oil residual products, bitumens, oil binders, and coal ashes are a complex system that includes highly condensed carbo- and heterocyclic compounds and products of their compaction. They are characterized by instability of the chemical composition, thermal instability of the compounds that make up their composition, as well as the ability to destroy the colloidal structure when the temperature rises (stratification and precipitation). Petroleum bitumens and pitches differ from coal furnaces by a significantly higher content of oils and resins. The method for determining the group chemical composition of bitumens and pitches is based on the different relationships of the components that make up their composition to solvents and consists in dissolving a sample of substances in an organic solvent, followed by determining the mass of the filtered and dried residue. It is customary to distinguish three main groups of substances from the pitch:

α -fraction (carboids and carbenes), containing substances with a molecular weight of 800–850, insoluble in toluene;

β -fraction (asphaltenes), containing substances with a molecular weight of 500–550, soluble in toluene but insoluble in isooctane and petroleum ether;

γ -fraction (maltenes), containing substances with a molecular weight of 200–350, soluble in isooctane and petroleum ether. When using pitch as a binder in electrode and anode production, the α -fraction is divided into two components: α_1 -fraction insoluble in quinoline and α_2 -fraction soluble in quinoline but insoluble in toluene. The α_2 -fraction is understood as oligomers of asphaltenes and partially mesophase-liquid crystalline products of transformations of high-molecular-weight compounds of oil systems [12]. The group composition of oil pecks, to a large extent, determines their technological properties, namely: γ -fraction improves the plasticity of pecks; α_2 - and α -fractions give pecks the necessary binding and sintering properties.

3.1.2. Reasons for the Existence of Residual Oil in the Reservoir

The main reason for the impossibility of achieving complete displacement of oil by water from reservoirs during their flooding is the immiscibility of oil and water, because of which an interface is formed between these liquids and oil is retained in a porous medium by capillary forces. Incomplete displacement in flooded areas of the formation is due to the hydrophobization of reservoir rocks. This is due to the adsorption of heavy oil components on the surface of rock grains; the difference in viscosities of the displacing and displaced liquids, which leads to hydrodynamic instability of the oil–water contact; drops or globules of oil, accumulations of oil remain behind the displacement front [14].

Oil remains in the porous medium in the form of films on rock grains and globules located in dead-end pores or in places of the porous medium bypassed by water (Figure 2). If oil is displaced from the reservoir by a liquid that mixes with it, then as a result of molecular diffusion, the solvent liquid penetrates into the oil, oil hydrocarbons into the solvent, and over time, the oil is completely washed out of the reservoir. Solvents, having washed out the oil, will remain in the reservoir; therefore, they should be cheaper than oil [15]. Alcohols, ethers, and hydrocarbon sulfur can be used as solvents that displace oil from the formation, but these are expensive substances. Therefore, natural gas, water, carbon dioxide, and air are used to displace oil.

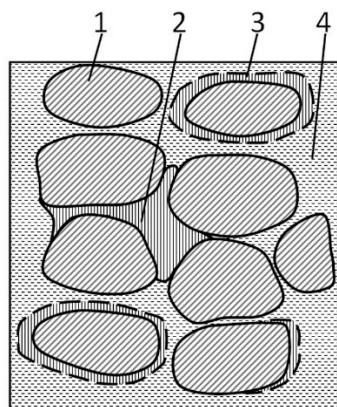


Figure 2. The structure of the porous medium of the rock: 1—hard rock grains; 2—residual oil in dead-end pores; 3—film oil; 4—water [14].

3.1.3. Conditions for the Effective Use of EOR

An important condition for the effective application of enhanced oil recovery methods is the correct choice of an object for a method or, conversely, a method for an object [16].

Methods applicability criteria determine the range of favorable physical properties of fluids and reservoirs, under which it is possible to effectively apply the method or obtain the best technical and economic development indicators. These criteria are determined based on a generalization of the experience of its application in various geological and

physical conditions, as well as the use of extensive theoretical and laboratory studies and analysis of technical and economic indicators of the method application.

There are usually three categories of criteria for the applicability of methods [17]:

Geological and physical: properties of reservoir fluids, depth and conditions of occurrence of an oil-saturated reservoir, reservoir properties and characteristics of an oil-bearing reservoir, and saturation of the pore space with reservoir fluids.

Technological: flooding rim size, the concentration of agents in the solution, well placement, injection pressure, selection of production well operation mode.

Logistics: availability of equipment, chemical reagents, and their properties.

The criteria of the first category are defining, most significant and independent. Technological criteria depend on the geophysical ones and are selected in accordance with them. Material and technical conditions, for the most part, are also independent and determine the possibility of fulfilling technological criteria [18].

4. Physical and Chemical Methods of Enhanced Oil Recovery

Physico-chemical methods provide an increase in displacement and sweep efficiency at the same time and are designed to extract slick and capillary-retained oil from waterflooded formations. The addition of special chemicals to water allows you to create solutions that reduce interfacial surface tension and change the ratio of the mobilities of the displacing and displaced phases. As a result, the displacement efficiency increases [19]. When oil is displaced from the reservoir by a reagent that mixes with it, the interfaces between the oil and the displacer are eroded, capillary forces “disappear”, and oil dissolves in the displacer. As a result, it can be completely or partially removed from the reservoir area covered by the displacement process.

4.1. Displacement of Oil by Aqueous Solutions of Surface-Active Substances (Surfactants)

From the very name “surfactants”, it follows that adding them to the injected water changes the physical and chemical properties of the aqueous solution—the oil displacer, reduces the surface tension at the “water–oil” interface, increases the hydrophilicity of the surface of the pore channels, i.e., rock grains become more wetted by water [20]. There is an increase in the coefficients of oil displacement by the aqueous phase during forced displacement and capillary impregnation, in a change in the relative phase permeabilities of porous media [21,22]. This is caused by surfactant adsorption on the surfaces of pore channels.

4.2. Surfactant Adsorption

Adsorption is the process of precipitation of a surfactant from an aqueous solution and its settling on the surface of pore channels under the action of forces of intermolecular interaction.

Film oil covers the hydrophobic part of the pore surface of the formation in the form of a thin layer or in the form of adhering droplets held by adhesion forces. The work of the adhesion forces W_a , required to remove film oil from a unit surface of pores into the aqueous phase that fills the pores, is determined by the Dupré or Dupré–Young equations [23]. It is better to wash the oil with water or solutions that wet the rock well.

The addition of surfactants to water leads to a change in the ratio of free surface energy values due to the adsorption processes of surfactants at interfacial interfaces. This process is largely determined by the specific surface of the collector and the adsorption activity of the surface of the porous medium [24].

The amount A of the surfactant adsorbed on the surface of hard rock grains is determined by Langmuir isotherms [25]:

$$A = \frac{c}{(a + bc)} \quad (1)$$

and Henry:

$$A = \frac{c}{a} \quad (2)$$

where c is the specific concentration of surfactants in water, kg/m^3 ; a and b are coefficients determined experimentally. Since the surfactant is added to the water injected into the formation to determine the amount of surfactant sorbed on the surface of the hard rock grains, equations for water filtration with surfactants and oil, equations for determining water saturation and calculating concentrations are used in the derivation of which Henry or Langmuir isotherms are used [26]. There are two physical models used to describe the processes occurring in the board: piston and non-piston displacement of oil by water. Moreover, in the second case, the models of Buckley–Leverett, Rapoport–Lees and others are used [27]. The solution of the formulated problems is carried out either by approximate or numerical methods. For rectilinear-parallel filtration with piston displacement of oil by water, an exact solution is possible [28]. Figure 3 shows a diagram of the piston displacement of oil by an aqueous solution of surfactants. The increase in oil in Region 2 compared to Region 1 (oil bank) is associated with additional oil displaced from Region 1 due to surfactant adsorption in Region 1.

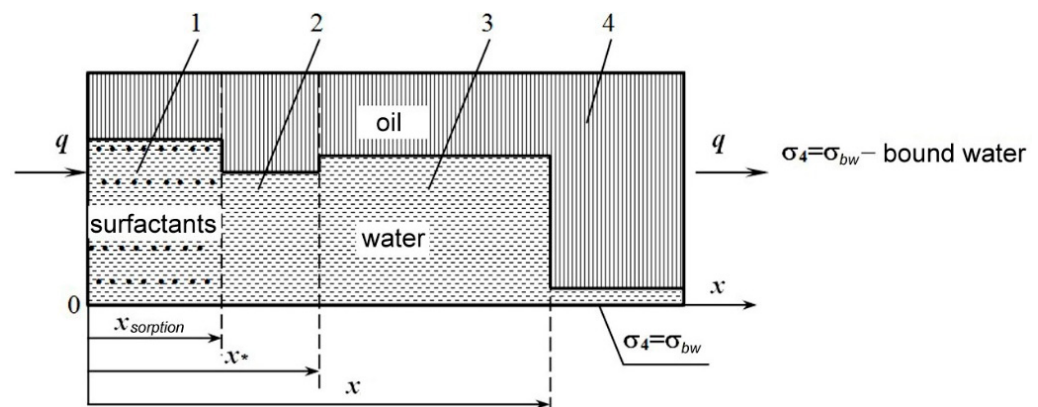


Figure 3. Scheme of the piston oil displacement by the surfactant solution: 1– $0 \leq x < x_{sor}$ is the area in which the surfactant is adsorbed; x_{sor} is the sorption front; 2 – $x_{cor} < x < x^*$ is an area occupied by oil displaced as a result of surfactant impact; x^* is the front of oil displacement by an aqueous solution of surfactants. 3 is the area of oil displacement by pure water $x^* < x < x_f$, where x_f is a coordinate of the front of oil displacement by water; 4 is an area of the reservoir not covered by development [28].

4.3. Surfactant Compositions

Surfactants are chemical compounds capable of changing phase and energy interactions on various interfaces due to adsorption: they are liquid–air, liquid–solid, and oil–water. Surface activity, which many organic compounds can exhibit under certain conditions, is due to both the chemical structure, in particular, the amphiphilicity (polarity and polarizability) of their molecules, and external conditions. They are the nature of the medium and the contacting phases, surfactant concentration, and temperature [29].

According to the ionic characteristic, all surfactants are usually divided into two large groups: nonionic compounds, which do not dissociate into ions when dissolved in water, and ionic compounds. Depending on which ions determine the surface activity of ionogenic substances, they are usually divided into anionic (AS), cationic (SCS) and ampholytic. Anionic surfactants are more active in alkaline solutions, cationic surfactants in acidic ones, and ampholytic surfactants in both [30].

The method of flooding with aqueous solutions of surfactants can be effectively used in strictly defined geological and physical conditions, as evidenced by many years of experience (since 1971) in the use of surfactants in Tataria to enhance oil recovery from terrigenous Devonian deposits, as well as the use of surfactants in the Samotlor field [31,32]. Numerous experimental studies carried out at «TatNIPIneft» have shown that the use

of concentrated surfactant solutions under conditions of primary oil displacement from models of terrigenous rocks significantly improves the process of oil displacement. The maximum increase in displacement efficiency compared to water was 2.2–2.7% [33]. A somewhat larger increase in displacement efficiency, equal to 3.5–4%, was obtained using models of low-permeability porous media. Among nonionic surfactants, OP-10, AF9-4, AF9-6, AF9-10, and AF9-12 are the most widely used, mainly due to the large volumes of their industrial production. Ionic surfactant compounds include NChK, sulfonic acid, NP-1, and isolates A and B [32].

4.4. Displacement of Oil from the Reservoir by Polymer Solutions

The coefficient of mobility is the ratio of the phase permeability to the viscosity of the liquid. For oil and water, the mobility coefficients are as follows [34]:

$$K_o = \frac{k_o}{\mu_o}, K_w = \frac{k_w}{\mu_w}. \quad (3)$$

Darcy's law for water and oil has the form:

$$v = -\frac{k}{\mu} \text{grad} p. \quad (4)$$

With an increase in the pressure gradient, the filtration rate of the polymer solution increases by a smaller amount than that when filtering pure water (Figure 4 [35]).

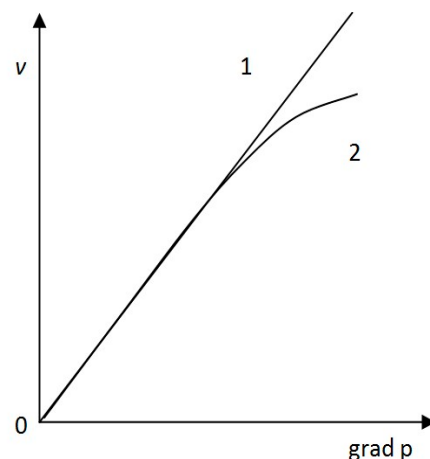


Figure 4. Dependence of the filtration rate of (1) Newtonian and (2) dilatant fluids on the pressure gradient [35].

Along with surfactants, adsorption is observed during filtration of an aqueous solution of PAA. At low concentrations of PAA in water, the amount of the sorbed substance corresponds to the Henry isotherm (4).

PAA is available as a gel, solid granules or powder. The PAA concentration in water is 1–5% for gel and 0.08–0.4% for solid polymer. Due to the high sorption of PAA, the concentration of PAA is adjusted to a value at which the dynamic viscosity of an aqueous solution increases by a factor of 5–6 [33].

It is believed that it is expedient to use an aqueous solution of PAA at an oil viscosity of (10–30) MPa. As a result of PAA sorption by a porous medium, when oil is displaced, a sorption front is formed, as well as when oil is displaced by aqueous surfactant solutions (Figure 5).

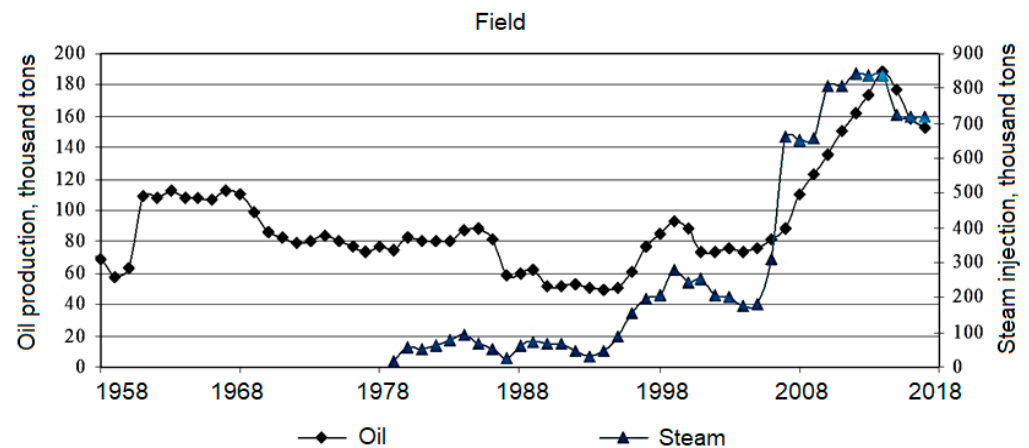


Figure 5. Change in the current oil production due to steam injection [36].

It has been experimentally established that with an increase in the concentration of polymers, the phase permeability of the wetted phase decreases, while the permeability of hydrocarbon liquids increases even at the same saturation [36].

4.5. Micellar-Polymer Flooding Method

The method of complex impact on the oil reservoir by pumping a mixture of surfactants, alcohols, oil solvents, an aqueous solution of PAA and water into it is called the micellar flooding method. When the concentration of surfactant in the solution is higher than the critical one for micellization, the surfactant is present in the solution in the form of clumps (micelles), which are capable of absorbing liquids constituting their internal phase [37]. At a high concentration of surfactants, together with oil and water, they form oil–water aggregates—micelles 10^{-5} – 10^{-6} mm in size (Figure 6).

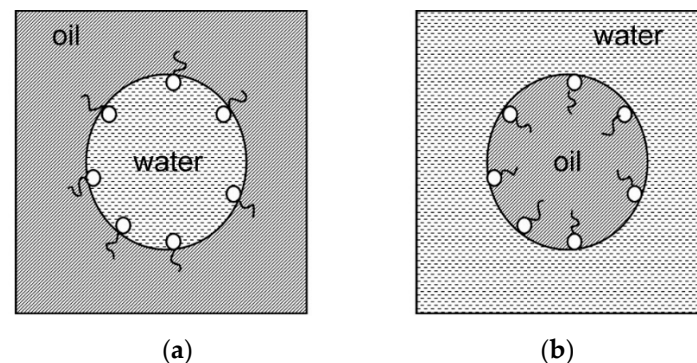


Figure 6. Schemes of the structure of micelles on (a) oil-based and (b) water-based Micellar solutions with an aqueous external phase mix well with water [38].

Externally, micellar solutions are transparent or translucent liquids; they belong to Newtonian liquids [38].

When using a relatively small amount of hydrocarbons—oil solvents—alcohol, sulfides, or other surfactants, at the complex solution–oil contact, a region of complete mixing of oil with such solution is created. At the oil–solution contact, the surface tension drops sharply. An area of low surface tension is created between water and oil. As you move away from the contact (displacement front) towards the injection wells, the proportion of water in the solution increases until it turns into pure water. Near the injection line, the solution passes into the water, the viscosity of which is less than the viscosity of the solution. In this case, a less viscous liquid (water) should displace a more viscous one (micellar solution). The displacement ratio is reduced.

The compositions of micellar solutions are different: for example, sulfonates—6%, surfactants OP-4—1.2%, isopropyl alcohol—1.2%, kerosene—51.6%, and water—40%. On the other hand, there are sulfonates—8%, surfactants OP-4—2%, oil or hydrocarbons (C5+)—30%, and water—60% [39].

4.6. Change or Alignment of the Injectivity Profile (RWY)

To improve reservoir coverage by waterflooding, flow-diverting technologies are often used, which change the direction of the flow of injected fluids. This is achieved by increasing the filtration resistance of the flooded sections of the formation by pumping into it such reagents that form various plugging plugs in the washed zone when mixed with formation water. At the same time, a waterproofing screen is created in the highly water-cut interlayer, which deflects the flows of water injected into the reservoir into the oil-saturated layer, increasing the oil recovery factor [40]. Flow diverting technology is based on the injection of limited volumes of special reagents into injection wells, designed to reduce the permeability of highly permeable reservoir layers (up to their blocking) in order to equalize the good injectivity along the reservoir section and, thereby, create a more uniform displacement front and reduce water breakthroughs to producing well. Flow-diverting technologies allow the creation of strong barriers to water filtration and increase oil recovery by increasing sweep efficiency. These technologies are used at the final stage of development or when solving problems related to repair and insulation works [40].

A review of existing diversion technologies showed that there are more than 100 technologies today. From 2010 to 2020, more than 30,000 operations were carried out in Russian fields only due to the use of flow-diverting technologies, which made it possible to obtain an additional 53 million tons of oil. So in 2020, about 9 thousand operations were performed, while additional oil production per well amounted to 0.3 to 1.6 thousand tons. Due to flow-diverting technologies, companies produced over 9.5 million tons of oil, which is about 8% of the total share of additional cash income for 2020 [31,41].

All main methods of flow-diverting technologies can be divided into the following groups: polymeric, gel-forming and viscoelastic compositions; dispersed systems; sediment-forming compositions; microbiological impact.

Changing or increasing (leveling) the injectivity profile of injection wells is sometimes called flow-diverting technologies [40], which is not correct in our opinion since the direction of the injected water flows may not change. However, an increase in the injectivity interval into which the injected water enters occurs. Alternatively, it should occur with the correct selection of chemical reagents and reliable geophysical data on the injectivity interval.

The reservoir, consisting of several interlayers of different permeability and thickness due to the dissection, is developed unevenly, the Kazemi or Serra model [40]. Oil is displaced along highly permeable interlayers (IP), and consequently, rapid watering of products occurs. Low-permeability interlayers practically do not work; oil is not displaced from them. For isolation, cutting off highly permeable interlayers with larger pore channels, specially selected chemical solutions are pumped into the pore space of these channels. The sizes of molecules of the selected chemical compounds are comparable with the sizes of high permeability channels. Under the influence of temperature and interaction with the surface of the pore channels, they form a viscous immobile or inactive substance, which, with an increase in pressure at the bottom of the injection well, practically does not move and does not allow water to move along them [41]. This solution does not penetrate into low-permeability channels. During subsequent injection, water begins to flow into the formation with low filtration properties, and oil is displaced from layers that were not previously covered by flooding. This increases the sweep efficiency of the reservoir by waterflooding and, consequently, oil recovery. The scheme for changing the injectivity profile is shown in Figure 7.

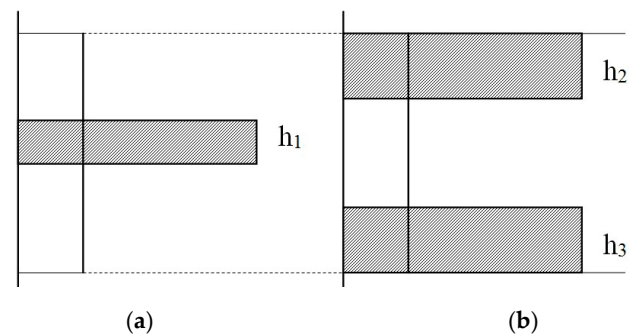


Figure 7. Scheme of changing the injectivity profile: (a) h_1 —the thickness of the high-permeability interlayer before applying the technology; (b) h_2 , h_3 —the thickness of the low-permeability interlayers after isolation of the high-permeability interlayer [41].

In the Samotlor field [31], the widespread use of FFP technologies began in 1995. Over the entire period of development, the accumulated volume of additional oil production due to FFP methods amounted to more than 14 million tons. However, in the whole field, their efficiency is declining. In some cases, the use of the same technologies gives diametrically opposite results [42].

At the same time, over ninety different compositions have been used in the Samotlor field in recent years, including the most effective Bright Water™ [31]. Additionally, if the range of the compositions used in terms of their physical and chemical properties is already adapted to the thermobaric conditions of the reservoirs, then approaches to the selection of areas, the order of impact on wells, determination of injectivity volumes, frequency of work, selection of reagent compositions depending on geological conditions of the reservoirs require further improvement.

The used chemical reagents are divided into three main types of compositions: dispersed (according to the principle of the prevailing role of the dispersed phase); precipitate (gelling solutions that form gels or precipitates; and complex compositions, consisting, for example, of gel-forming and precipitate-forming compositions), as well as a mixture of gel-forming and dispersed compounds. Complex compositions imply a combination (injection into the reservoir) in a certain sequence of individual compositions, different in their rheological and dispersed properties, the main purpose of which is a complex effect on the near and remote zones of the reservoir [42].

4.7. Selection of Sites and Wells for the Application of Technology for Increasing the Injectivity Profile

The priority prerequisites for the application of this technology in areas with a significant degree of depletion of reserves and high water cuts are [43]:

1. The presence of a pronounced geological filtration heterogeneity of the reservoir section (a prerequisite for the advanced development of reserves in individual interlayers). First of all, areas with the most pronounced heterogeneity are processed.
2. Correspondence of the degree of recovery of oil reserves to the water cut of the products: the lower the correspondence, the need for work is dictated first (this indicates the presence of pinched residual recoverable reserves).
3. The ratio of the degree of pumping (as a percentage of the pore volume of the site) and the selection from the NIH (the efficiency of the RPM system). The larger this ratio, the lower the current efficiency of the reservoir pressure-maintenance system and the more volumes of water are injected and extracted without doing useful work on the frontal oil displacement. This fact also indicates the relative value of artificially pinched residual recoverable reserves. Therefore, first of all, attention should be paid to areas that have the highest ratio of pumping and selection from NIH.
4. *Ceteris paribus*, the sections of the production facility corresponding to the Kazemi model are processed first. That is, they have high and low permeability interlayers.

5. Under conditions of a homogeneous geological structure, for example, in monolithic deposits, the permeabilities determined for production and injection wells are compared, respectively, according to pressure build-up and efficiency.

Differences in the direction of greater permeability around injection wells indicate how the reservoir “breathes”, i.e., how the properties of the reservoir depending on the deformation processes that occur in the reservoir because of changes in reservoir pressure. The greater this difference, the more prone the formations from the side of injection wells are to stratification and flushing, which leads to the formation of rill filtration. An indirect confirmation of the existing difference in the filtration properties of such formations is the average specific indicators per $1 \text{ m}^3/(\text{day MPa})$ for the injectivity of injection wells and for the specific production rate of surrounding production wells [18].

4.8. Hydrodynamic Methods for Enhanced Oil Recovery

Hydrodynamic methods are used at the third and fourth stages of the development of production facilities; they are secondary methods of oil production and are among the most economical methods of enhanced oil recovery. Hydrodynamic EORs are subdivided into changing the direction of filtration flows, cyclic waterflooding, and forced fluid withdrawal. Their combined application should be defined as combined non-stationary waterflooding since each of these methods is based on non-stationary fluid filtration [28].

4.8.1. Changing the Direction of Filtration Flows

The technology of the method lies in the fact that at the production facility, the injection of water into injection wells periodically changes [31]. In the first stage, some injection wells are working; others are not working (Figure 8a). In the second stage, injection into these wells is stopped and transferred to others (Figure 8b). As a result, the direction of filtration flows changes. Figure 8 shows one of the possible schemes for changing filtration flows.

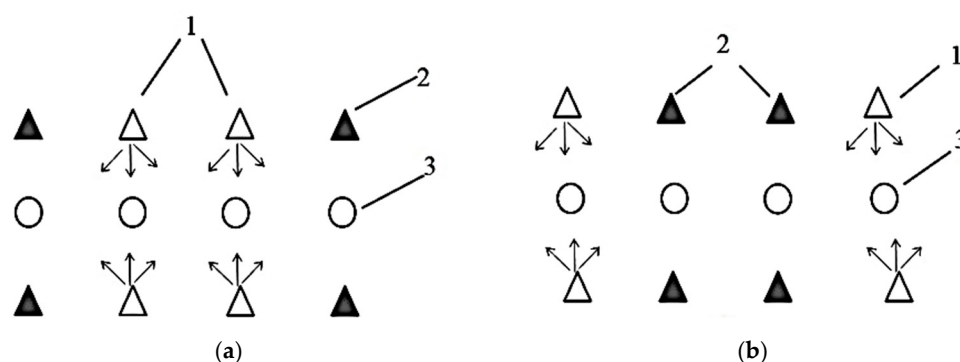


Figure 8. Scheme of changing the direction of filtration flows: (a) operation of the first group of injection wells; (b) shutdown of the first group of wells, operation of the second group of injection wells, 1—working injection wells, 2—idle injection wells, 3—production wells [12].

The method is technological; it requires only a small reserve of power of pumping stations and the presence of an active waterflooding system. For its application, transverse cutting rows are used, including a combination of near-contour and intra-contour flooding. The application of this method makes it possible to maintain the achieved level of oil production, reduce the current water cut and increase the coverage of reservoirs by flooding [12].

4.8.2. Forced Liquid Withdrawal (FOL)

Forced fluid withdrawal consists of a gradual increase in production well production rates. The essence of the method is to create high-pressure gradients by increasing the drawdowns, therefore, reducing the bottom hole pressure in production wells and increas-

ing the injection pressure. At the same time, in heterogeneous, heavily watered reservoirs, residual oil pillars, lenses, dead-end and stagnant zones, and low-permeability interlayers are involved in development [39]. Method applicability conditions are as follows:

1. Water cut of products of not less than 90–95% (beginning of the final stage of development);
2. High well productivity factors at the beginning of the operation;
3. when the bottom hole pressure decreases, the reservoir is stable (does not collapse), and the discharge pressure should not exceed the tensile strength of the rock;
4. The casing is in good condition; there are no water flows from other horizons;
5. The throughput of the system for collecting and preparing products is sufficient for the use of FOL.

Fluid flow rates are assigned according to the maximum oil flow rate of each well selected for the application of the method. When applying forced fluid withdrawal, it is necessary to compare various options for the development of oil deposits with oil of different viscosities. These options differ in the dynamics of forcing (increasing) fluid withdrawal at a constant rational maximum bottom hole pressure of injection wells and a rational minimum bottom hole pressure of production wells [17].

In order to increase the inflow and injectivity profiles, before the application of the VLF, work is carried out to change the injectivity profiles (RIP) at injection wells and the inflow profiles at production wells (Section 4.6. Change or alignment of the injectivity profile). It is recommended to carry out acid treatments, repair and insulation works (RIW) to eliminate fluid overflows from overlying formations [22].

4.8.3. Cyclic Flooding

The main criteria for the application of cyclic waterflooding are as follows [43]:

1. The presence of layered heterogeneous permeability or fractured porous hydrophilic reservoirs;
2. High residual oil saturation of low-permeability interlayers;
3. The technical and technological possibility of creating a high amplitude of pressure fluctuations (flow rates), which can reach 0.5–0.7 of the average pressure drop between injection and production wells (average flow rate).

Cyclic flooding is used for reservoirs corresponding to the Kazemi model [11]. A layered reservoir consists of at least two interlayers: high permeability (HP) and low permeability (LP). There is a hydrodynamic connection between VP and NP. The cycle is divided into two half cycles. In the first half-cycle, when the displacing fluid is injected, part of the water flows from the VP to the NP. Another part of the water is filtered along the VP in the direction of the production well, while the oil is displaced by water from the VP. Figure 9 shows the operation of the first half cycle. In the second half-cycle, when the pressure on the injection well decreases, or the injection is stopped, the pressure in the high-permeability layer drops and becomes lower than the pressure in the OP. As oil is more compressible than water, due to the hydrophilicity of the reservoir, water is retained in the OR by capillary forces; oil flows from the OR to the VP. During the first half-cycle of the second cycle, the injection well starts working again, the pressure in the reservoir increases, and the oil that enters the VP from the bottom hole of the production wells is displaced [16].

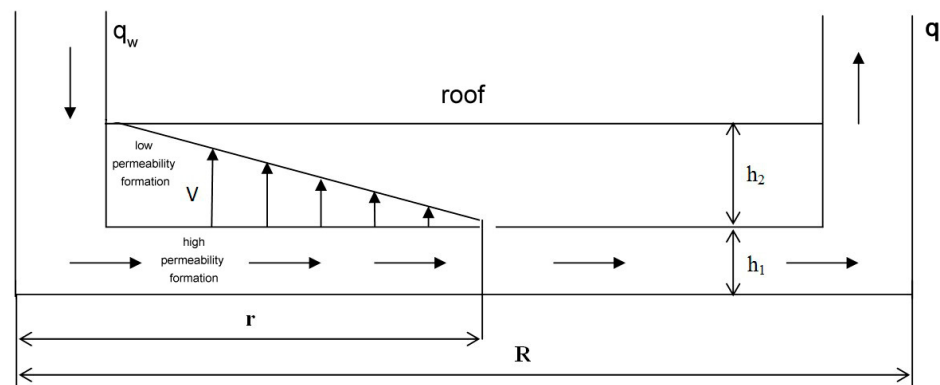


Figure 9. Scheme of displacement of oil by water. First half-cycle: R is the distance between injection and production wells; h_1 and h_2 are the thicknesses of the VP and NP; V is the flow rate from the VP to the NP; r is the coordinate; q_w is the water flow rate; q is the liquid flow rate [22].

Let P_0 be the reservoir pressure in a low-permeability interlayer; P_h is the pressure at the bottom of the injection well; $P_1(r, t)$ is the current pressure in VP; r is the coordinate; t is time. During the first half-cycle, the relation [10] is fulfilled:

$$P_0 \leq P_1(r, t) \leq P_h. \quad (5)$$

The flow rate from VP to NP is determined by:

$$V = 2\lambda_2(P_1(r, t) - P_0) \text{ for } t \leq t_2, \quad (6)$$

$$V = 2\lambda_2(P_1(r, t) - P_0)e^{-3\lambda_1(t-t_2)} \text{ for } t > t_2. \quad (7)$$

where $t_2 = \frac{h_2^2}{12\chi_2}$ —time to reach the top of the formation; χ_2 —coefficient of piezoconductivity NP.

For each fixed r , the flow rate V first changes according to (6), then when the upper boundary of the reservoir h_2 is reached, relation (7) is satisfied and the flow rate decays. Parameters λ_1 and λ_2 are characteristics of the NP.

$$\lambda_1 = \frac{\chi_2}{h_2^2} \quad (8)$$

$$\lambda_2 = \frac{\varepsilon_2}{h_2^2} = \frac{k_2}{h\mu_w} \quad (9)$$

where ε_2 is the coefficient of hydraulic conductivity of NP; k_2 is NP permeability; μ_w is the dynamic viscosity of water. Here, changes in porosity with pressure and flow rate with saturations are not taken into account.

4.8.4. Combined Non-Stationary Flooding

The considered technologies are changes in the direction of filtration flows and cyclic waterflooding; FLC is a non-stationary physical process. Pressures and pressure gradients depend on time. The use of cyclic waterflooding is based on the existence of a hydrodynamic connection between interlayers of different permeability. The extraction of oil from a low-permeability reservoir, the flow of oil in the second half-cycle from OP to EP, does not formally increase the sweep efficiency. However, it allows involving low-permeability differences in the effective thickness of the opened interval in the development [43]. Therefore, the thickness coverage ratio increases. Over time, the amount of oil flowing from OR to WP decreases, and the sweep efficiency also decreases. However, it allows involving low-permeability differences in the effective thickness of the opened interval into the de-

velopment. Therefore, the thickness coverage ratio increases. Over time, the amount of oil flowing from OR to WP decreases, and the sweep efficiency also decreases. However, it allows involving low-permeability differences in the effective thickness of the opened interval in the development [44]. Therefore, the thickness coverage ratio increases. Over time, the amount of oil flowing from OR to WP decreases, and the sweep efficiency also decreases.

Combined non-stationary flooding should include the use of technology for changing the direction of filtration flows in the presence of a hydrodynamic connection between interlayers of different permeability, that is, the possibility of joint implementation of two technologies: changing the direction of filtration flows and cyclic flooding. In this case, the sweep efficiency of the formation by flooding increases both due to an increase in the drainage area and due to the influx of oil from low-permeability interlayers [43]. As the fluid inflow increases, it is necessary to replace the pumping equipment with a more productive one, which is selected in accordance with the increased well productivity factor. However, the replacement of the ESP with a higher flow, in this case, is not a direct method of the FLC since the water cut does not approach the critical one, and the operational facility is at the second-third stage of development. Combined non-stationary flooding is possible only in hydrodynamically connected interlayers [45].

5. Gas and Water–Gas EOR

5.1. Displacement of Oil from the Reservoir by Carbon Dioxide (CO₂)

To displace oil from the reservoir, carbon dioxide CO₂ can be used, which mixes with oil at a temperature of 300–310 °K and pressure above 10 MPa. However, resins and asphaltenes contained in the oil are slightly soluble in CO₂ and may precipitate. Critical values are CO₂ P = 7.38 MPa, T = 305 °K. For complete solubility of CO₂, it is necessary to increase the temperature and pressure above critical values, for example, P = 30 MPa, T = 360 °K [46].

Another way to use CO₂ is as follows. Water is pumped into the formation with carbon dioxide dissolved in it (carbonized water). Due to the greater chemical “affinity” of oil and CO₂, upon contact with carbonized oil water, CO₂ molecules diffuse, loosen heavy oil films on the surface of rock grains, and make these films mobile, which leads to an increase in the amount of oil to be recovered [47].

Of the considered technologies, the displacement of the CO₂ slug by pushed water has an advantage; it allows you to extract more oil from the reservoir since it is unreliable to rely only on the separation of heavy oil films from rock grains. Such films can make up a very small fraction of the residual oil [48]. To apply this method, it is necessary to have a sufficient amount of cheap CO₂ to ensure profitable production.

5.2. Displacement of Oil by Hydrocarbon Gases

Currently, much attention is paid to the utilization of associated petroleum gas. One of the ways to use associated gas is to use it as a reagent injected into injection wells in order to increase the oil displacement efficiency [49].

To increase oil recovery, the following gases are used: dry hydrocarbon gas, high-pressure gas, enriched gas and gas–water (water–gas) mixture. When using liquefied hydrocarbon gases and other liquid hydrocarbon solvents as displacing agents, another problem arises in extracting the solvent remaining there, the price of which can significantly exceed the cost of oil [50].

Oil displacement by the reagent can be immiscible or miscible (without the existence of a phase boundary). The miscibility of gas with oil in reservoir conditions is achieved only in the case of light oils (the density of degassed oil is less than 800 kg/m³). The injection pressure of dry hydrocarbon gas is 25 MPa or more, and the pressure of enriched gas is 15–20 MPa. When mixing (dissolving) gas with oil, the viscosity of oil decreases, the mobility of oil increases, including flow rates (Dupuy’s formula [51]), and, ultimately, oil recovery.

The main criteria for the effectiveness of the hydrocarbon gas injection process are as follows [52]: Formation dip angles; Reservoir depth; When the reservoir is homogeneous; Hydrodynamic isolation of the formation.

The injectivity of wells is established empirically or according to the formula for the flow rate of a gas well, multiplying the calculated value by the experimental coefficient. To maintain the pressure at the existing level, the total flow rate of the injected gas must be equal to the sum of the oil, water and gas flow rates, reduced to reservoir conditions. The bottom hole pressure is calculated, taking into account pressure losses due to friction and pressure of the gas column. Typically, injection pressure is 15–20% higher than reservoir pressure [53].

For a layered formation consisting of interlayers of different permeability, premature gas breakthroughs through high-permeability interlayers are possible, which sharply reduces the displacement efficiency. Gas breakthroughs are determined by monitoring the GOR and changing the chemical composition of the gas. To prevent a gas breakthrough, liquid withdrawal from wells is reduced, and up to their shutdown, the volume of injected gas is reduced, and liquid is pumped together with gas [54].

5.3. Water–Gas Cyclic Impact

The technology of cyclic water–gas treatment consists of the fact that gas and water are injected into the reservoir alternately by rims or simultaneously in a mixture into the same or separate injection wells [55].

Physically, the oil displacement mechanism is as follows. Water fills small pores and narrows the pore channels, thereby increasing the sweep efficiency. The gas injected into the reservoir, due to its greater mobility, occupies large pores, and the upper part of the reservoir partially dissolves in oil, increasing its mobility and thereby increasing the displacement efficiency. Thus, gas increases one of the factors of the oil recovery factor, and water increases the other [56].

Joint displacement of oil from heterogeneous reservoirs by water and gas is more effective for ultimate oil recovery than the separate displacement of oil only by water or gas. By choosing the optimal operating mode, reservoir recovery can be increased by 7–15% compared to conventional waterflooding. The main condition for the optimality of the water–gas treatment process is to ensure a uniform distribution of the injected gas over the water-flooded volume of the reservoir, in which there is a simultaneous breakthrough of gas and water into production wells. The duration of injection cycles for each agent is 10–30 days [57,58]. By choosing the optimal operating mode, reservoir recovery can be increased by 7–15% compared to conventional waterflooding. The main condition for the optimality of the water–gas treatment process is to ensure a uniform distribution of the injected gas over the water-flooded volume of the reservoir, in which there is a simultaneous breakthrough of gas and water into production wells. The duration of injection cycles for each agent is 10–30 days [57]. By choosing the optimal operating mode, reservoir recovery can be increased by 7–15% compared to conventional waterflooding. The main condition for the optimality of the water–gas treatment process is to ensure a uniform distribution of the injected gas over the water-flooded volume of the reservoir, in which there is a simultaneous breakthrough of gas and water into production wells. The duration of injection cycles for each agent is 10–30 days [58].

Disadvantages of water–gas cyclic impact: the injectivity of the injection well for each working agent decreases after the first cycle: for gas 8–10 times, for water 4–5 times due to a decrease in the phase permeability of the BFZ [58]. Depending on the structure and heterogeneity of the reservoir, the gravitational separation of water and oil can reduce the efficiency of the technology by 10–20%.

Ongoing laboratory studies show that the effect of changing the ratio of the proportions of injected water and gas is insignificant. The sample sizes are small, almost uniform, and, therefore, it is practically impossible to create an environment close to the real reservoir under laboratory conditions. There are two options left: computer modeling, or experimen-

tal fieldwork, depending on good knowledge of the geological and physical structure of the reservoir [59].

6. Thermal Methods of Enhanced Oil Recovery

Thermal methods are promising methods of enhanced oil recovery. In the literature, terms are used to describe such actions on the formation: thermal methods [60,61].

Thermal methods are subdivided into thermophysical ones: injection of hot water, steam, injection of hot water containing chemical reagents, steam-cycling treatment of wells, and thermochemical: in situ combustion. Hot water and steam are called heat carriers. Thermal methods are used for deposits containing high-viscosity oils; for reservoirs with reservoir temperatures close to the saturation temperature of the oil with paraffin; for deposits of bituminous clays [62].

6.1. Physical Processes Occurring When Oil Is Displaced by Heat Carriers

The initial value of reservoir temperature and its distribution in the reservoir is determined by the geothermal conditions in which the field is located. Typically, reservoir temperature follows a geothermal gradient. During the development of the field, the reservoir temperature may change. Thus, the water injected into the reservoir has a different temperature. Processes associated with the release or absorption of heat occur in the reservoir. The temperature change will occur due to the hydraulic resistance of the filtering fluids due to the Joule–Thomson effect [63].

The distribution of reservoir temperature and its change is called the temperature regime. The change in the temperature regime occurs mainly due to thermal conductivity and convection (warm fluids have a lower density, they are lighter) [11,64].

A feature of the use of thermal methods is that along with the hydrodynamic displacement of oil, the temperature in the deposit increases. An additional thermal front of oil displacement by hot water is formed. Moreover, the hydrodynamic displacement front is ahead of the thermal displacement front since the transfer of heat from the coolant to warm up viscous oil does not occur immediately; it is delayed (Figure 10). An increase in oil, water and rock temperature leads to a decrease in oil viscosity, a change in the ratio of oil and water mobility, a change in relative permeability, residual oil saturation, to evaporation of light fractions, thermal expansion of the reservoir occurs (porosity changes, the volume of fluids filling it, i.e., saturation) [65].

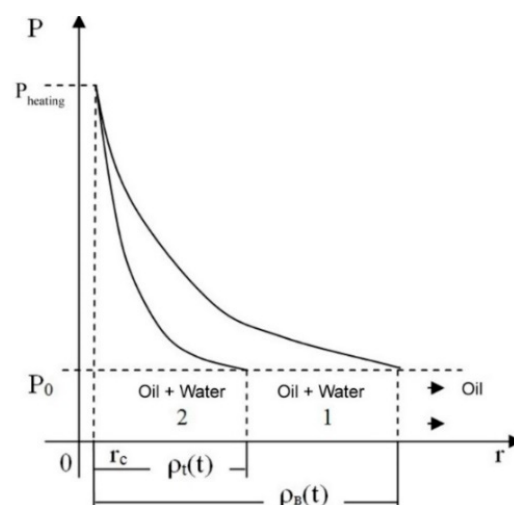


Figure 10. Scheme of oil displacement by hot water. 1—zone of displacement of cold oil by water, 2—zone of displacement of heated oil by hot water, $p_b(t)$ —radius of the hydrodynamic displacement front, $p_t(t)$ —radius of the thermal displacement front [65].

6.2. Displacement of Oil from the Reservoir by Hot Water and Steam

Hot water and steam, otherwise coolants, are produced in high-pressure steam generators (boilers) and pumped into the formation through injection wells of a special design and with special equipment designed to operate at high temperatures [66]. The disadvantage of using surface steam generators is large losses of heat (temperature) in surface communications and in the wellbore. When the coolant moves along the formation, heat losses occur through the roof and bottom of the formation. To reduce heat loss, layers with a thickness of more than 6 m are chosen, and areal grids of wells are used at a distance of up to 100–200 m between injection and production wells. The perforation interval is chosen in the middle part of the formation; the pipes are insulated, and the steam generator is brought as close as possible to the wells [67].

When steam is injected into the formation, depending on the thermodynamic conditions, it can turn into hot water. Therefore, when designing and implementing the injection of hot water and steam into the reservoir, it is necessary to know in what thermodynamic state the water is: liquid, in the form of steam or a mixture of water and steam [68], which is determined using the P–T diagram (Figure 11). The critical point—dew point C—corresponds to the state of water, in which the physical properties of the liquid and gas phases coincide. For water:

$$P_{cr} = 22.12 \text{ MPa}, T_{cr} = 647.30 \text{ }^{\circ}\text{K} (374.120 \text{ }^{\circ}\text{C}), \text{ density } \rho_{kp} = 317.76 \frac{\text{kg}}{\text{m}^3}.$$

If the pressure and temperature correspond to the point on the OS saturation line, then the water is both in the liquid and vapor state, the steam is called saturated, and above the OS saturation line, the water is in the liquid state, below the OS saturation line in the form of superheated steam [69].

Under atmospheric conditions, water and oil are insoluble. In 1960, laboratory research by academician Nadirova N.K. (Kazakhstan) [70] established that the solubility of oil in water is achieved at a temperature of 320–3400 °C and pressures of 16–22 MPa, that is, for thermobaric conditions close to critical. When the temperature of the oil–water solution drops to 18–200 °C, oil is completely released from the water. If the density of water under normal conditions is 1000–1020 kg/m³, then the density decreases with increasing temperature, and at a pressure close to the critical one, complete mixing of water and oil occurs, and the phase boundary is blurred [71].

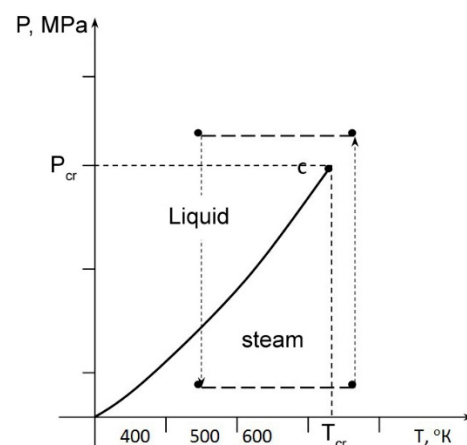


Figure 11. P–T diagram of pressure–water temperature, C—critical point [71].

Saturated steam acts as a thermal solvent for oil in the temperature range of 100–3700 °C and pressures from atmospheric to 22 MPa. The hot water sweep factor is higher than that for steam. Steam, as a low-viscosity working agent, usually moves near the top of the formation,

the sweep coefficient in thickness does not exceed 0.4, and in the area, it is 0.5–0.9. As a result, the recovery factor is 0.3–0.35 [71,72].

According to Yu. P. Zheltov, when displacing oil with hot water for additional extraction of 4000 m³ of oil, it is required to burn 1770 m³ of oil obtained from this amount. Conventional oil combustion is understood as the consumption of an equivalent amount of energy for heating water [32].

6.3. Thermal Rim Method

According to this technology, instead of continuous injection of the coolant after its penetration into the formation, after a certain time, water is pumped at the formation temperature. A heated region (thermal rim) is created in the reservoir, which moves from the injection well to the production wells under the influence of cold water injection into the reservoir [73].

In this case, when oil is displaced by a thermal rim, three displacement fronts are formed in the reservoir: 1—hydrodynamic-displacement of unheated cold oil by water; 2—thermal front-displacement of heated oil of low viscosity with hot water; 3—hot oil displacement front with cold water. Moreover, the 3rd front of hot oil displacement by cold water will lag behind the previous two. The heat of the hot oil will be transferred to the cold water, i.e., the reverse process of heat transfer will take place in the direction of the injection well. The viscosity of the displaced oil will increase, and the mobility coefficient will decrease. Unrecovered oil reserves will remain in the reservoir [74].

The use of thermal slug injection reduces oil recovery compared to continuous coolant injection, but much less energy is spent on steam or hot water preparation. To select the optimal sizes of thermal rims, special methods have been developed that take into account various geological and physical conditions of occurrence of reservoirs, the rate of injection of coolant rims into the reservoir, their parameters and forecasting of technological development indicators [75].

7. Combined Technologies for Enhanced Oil Recovery in Deposits with High-Viscosity Oils

As mentioned above, the use of injection of heat carriers into the reservoir is associated with high-energy costs and therefore increases the cost of production. Professor V. I. Kudinov and his collaborators have developed and implemented in Udmurtneftegaz software (v2.0) improved methods of thermal action along with changing time cycles and using chemical reagents to increase oil recovery in complex reservoirs [13,76].

The technology of pulse-dosed thermal treatment (IDTV) consists of cyclic variable injection of coolant and cold water into the reservoir in certain proportions. An effective temperature T_{ef} is created in the reservoir; this is the limiting temperature above which the viscosity of the oil decreases slightly [76,77]. Heating the reservoir above this temperature does not lead to an increase in oil recovery. The advantage of IDTV lies in limiting the coolant injected into the reservoir to the effective temperature. It is used for fractured-porous reservoirs (Warren–Root model [77]). Having multiple repetitions of steam injection cycles, steam penetrates into porous blocks and, after condensation, displaces heated oil into cracks.

For areal waterflooding systems, V.I. Kudinov proposes thermal cyclic stimulation of the formation. In this case, in addition to the central injection wells, alternate production wells are used for coolant injection, which work either as production wells or as injection wells. Thus, the sweep efficiency of the formation is increased by the impact of the area of production area [32].

7.1. Thermopolymer Formation Stimulation (TPV)

The TST technology is based on the injection of a PAA solution with a concentration of 0.05–0.1%, heated to a temperature of 90–950 °C, into the reservoir [78]. The viscosity of a heated aqueous solution of polyacrylamide is 1.5–2 mPa·s. The viscosity of oil in the

fracture system decreases, and part of the hot solution, mainly hot water, impregnates the blocks, improves the hydrophilicity of the rock, increases the mobility of the oil, and thereby leads to its displacement. The same happens in layered reservoirs (models of Kazemi and Serra [40]). Having this technology, a combination or simultaneous physical impact of three methods is carried out: hydrodynamic, physico-chemical and thermal. As you move along the reservoir, the aqueous solution of the polymer cools down, its viscosity increases, and it becomes comparable to the viscosity of the displaced oil. The displacement efficiency increases [78].

A modification of the considered technology is cyclic in situ polymer thermal treatment. A coolant (hot water, steam) is pumped into the reservoir, including a cold aqueous solution of PAA. Several cycles of sequential injection of coolant and polyacrylamide are performed [79]. Additionally, similarly to the TPV technology, the simultaneous physical action of three methods is carried out: hydrodynamic, physico-chemical and thermal. Let us note that the technologies discussed above are applicable to fractured-porous reservoirs, as well as to formations consisting of hydrodynamically connected interlayers of different permeability [80].

7.2. Steam-Cycling Treatment of Production Wells

Steam-cycling treatment of production wells refers to the methods of intensification of inflow (MIP). During steam cycling treatments, steam is pumped into a production well for 15–20 days in a volume of 100–300 tons per 1 m of formation thickness [81]. Then the well is closed for 10–15 days to redistribute heat and countercurrent capillary displacement of oil from low-permeability interlayers (LP) into a high-permeability interlayer. Further, the well is operated until the maximum profitable production rate is reached within 2–3 months.

The physical essence of the process is as follows: steam liquefies high-viscosity oil and increases the oil mobility coefficient [82]. Depending on the change in temperature and pressure, the steam first passes into a two-phase state of steam-water, then after condensation, into hot water, which, invading low-permeability layers, reduces the viscosity of the oil located there. After the well is stopped, as well as during cyclic waterflooding, water begins to displace oil from the OR to the WP [83]. At the third stage of the good operation cycle, the pressure in the bottom hole zone drops, and the oil recovery increases due to its greater mobility. Thus, the technology implementation cycle consists of three stages. A full cycle lasts 3–5 months. Usually, 5–8 cycles are carried out over 3–4 years, along with increasing the duration of each cycle. If the layer is shallow, then the density of the grid of wells should be no more than 1–2 ha/well. For 1 ton of injected steam, on average, 1.5–2 tons of oil is produced for all cycles (with a decrease from 10–15 tons to 0.5–1 tons) [84]. The equipment used includes a steam generator, pipelines, thermal expansion joints, wellhead and downhole equipment.

When coolant is injected, complications may arise in good operation: sand production, emulsion formation, premature steam breakthrough, and heating of the casing string and production equipment. To prevent complications, the BHP is fixed, and the withdrawals are limited up to the shutdown of the wells [85].

7.3. In Situ Combustion

In situ, combustion (IG) is based on the ability of hydrocarbons (in this case, oil) to chemically react with oxygen. As a result of combustion, a large amount of heat is released in the reservoir; the temperature rises, and the physical properties of reservoir fluids and rock change. Unlike other thermal methods of enhanced oil recovery, HSV eliminates technical problems and heat losses that occur when it is generated on the surface and delivered to the reservoir by injecting heat carriers into it [13,86]. The call of combustion is carried out at the bottom of the well—the incendiary. An oxidizing agent (usually air) is pumped into the injection well while simultaneously heating the bottom hole formation zone using a downhole electric heater, gas burner, incendiary chemical mixtures, etc. As

a result, exothermic oil oxidation reactions are accelerated, which ultimately leads to the creation of a combustion process in the bottom hole formation zone [87,88].

During combustion, the heaviest oil fractions, called coke, are burned. The rest of the oil is heated the viscosity and density decrease, and the mobility of the oil increases. Lighter fractions pass into the vapor phase and participate in the displacement of liquid-heated oil. For various geological and field conditions, the concentration of coke can be 10–40 kg per 1 m³ of the reservoir. This important parameter of the combustion process is recommended to be determined experimentally in the laboratory. It has been established that with an increase in the density and viscosity of oil, the concentration of coke increases, and at high values of rock permeability, it decreases. It is believed that the combustion of coke releases heat in the amount of 29–42 MJ/kg [89]. To date, publications indicate that there are three main types of in situ combustion: dry, wet, and ultra-wet [90,91].

7.4. Dry In Situ Combustion

In dry in situ combustion, only air is injected to sustain combustion. The main part of the heat generated in the reservoir (80% or more) remains in the area behind the combustion front and is gradually dissipated into the rocks surrounding the reservoir. This heat has a certain positive effect on the process of displacement from adjacent parts of the reservoir not covered by combustion [60,92].

It has been established that in the case of maintaining in situ combustion by injecting only a gaseous oxidizer (air) into the formation, heat loss from the rock heated as a result of combustion occurs more slowly due to the low heat capacity of the airflow than when the rock is heated by a moving combustion front. When the combustion front moves, a part of the oil that remains in the reservoir after its displacement by combustion gases, water vapor, water, and evaporated light fractions of oil ahead of the combustion front is consumed as fuel [93].

Air consumption for oil production during dry in situ combustion, according to the results of field tests, varies in the range of 1000–3000 m³ (under normal conditions) per 1 m³ of oil [94].

The transfer of heat to the area ahead of the combustion front will bring the heat generated in the reservoir closer to the zones where oil is being displaced from the reservoir. Such heat transfer is associated with the acceleration of heat transfer in the reservoir due to the addition of water to the injected air [95].

7.5. Wet In Situ Combustion

The combination of in situ combustion and flooding is called wet in situ combustion. The essence of wet combustion lies in the fact that water injected along with the air in certain quantities, evaporating in the vicinity of the combustion front, transfers the generated heat to the area in front of it, as a result of which extensive heating zones develop in this area, formed by zones of saturated steam and condensed hot water (Figure 12). The process of in situ steam generation is one of the most important distinguishing features of the wet combustion process, which determines the mechanism of oil displacement from reservoirs [11,96,97].

The values of the ratios of the volumes of water and air injected into the reservoir are within the limits of 1–5 m³ of water per 1000 m³ of air (under normal conditions), i.e., the water–air factor should be (1–5)·10^{−3} m³. The specific values of the water–air factor are determined by various geological and field conditions for the implementation of the process. However, with an increase in oil density and viscosity (more precisely, with an increase in coke concentration), the required water–air factor decreases [98]. If the values of the water–air factor are less than those indicated, then the transfer of heat to the area ahead of the combustion front decreases. When water is injected in a larger amount, the wet burning method turns into other modifications of the combined stimulation of the formation by burning and waterflooding. It is important to emphasize that increased values of the water–air factor do not lead to the termination of oxidative exothermic processes in the reservoir,

even in the case of the termination of the existence of a high-temperature combustion zone. At the same time, its underestimated values cause a decrease in the efficiency of the thermal effect on the reservoir and the oil recovery process. Therefore, it is advisable to carry out the wet combustion process with the maximum possible values of the water–air factor. The temperature distribution in the reservoir during wet combustion is schematically shown in Figure 12 [99]. Therefore, it is advisable to carry out the wet combustion process with the maximum possible values of the water–air factor. The temperature distribution in the reservoir during wet combustion is schematically shown in Figure 12 [99]. Therefore, it is advisable to carry out the wet combustion process with the maximum possible values of the water–air factor. The temperature distribution in the reservoir during wet combustion is schematically shown in Figure 12 [99].

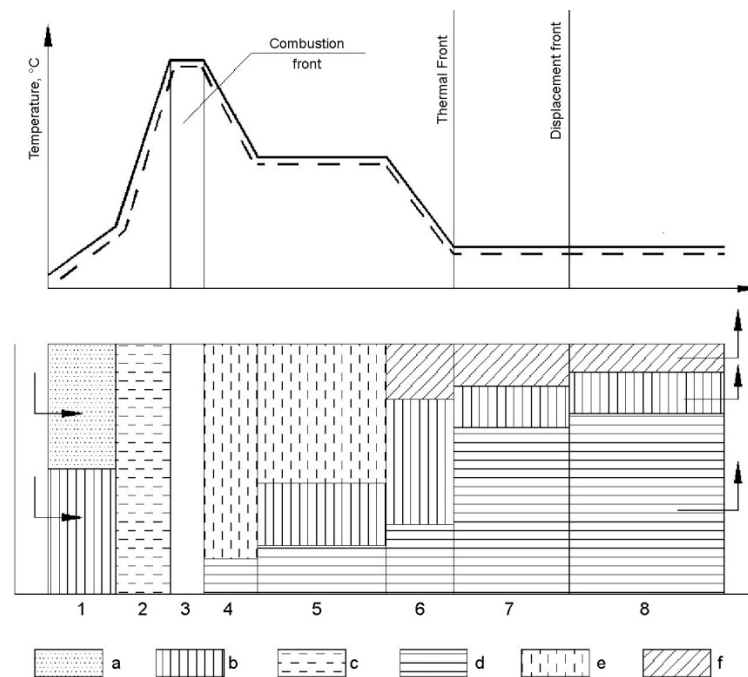


Figure 12. Scheme of the wet combustion process: a—air; b—water; c—a mixture of steam and air; d—oil; e—a mixture of steam and combustion gases; f—combustion gases. 1—filtration of injected water and air; 2, 4—superheated steam; 5—saturated steam; 6—displacement of oil by hot water; 7—displacement of oil by water at reservoir temperature; 8—oil filtration under initial conditions; 3—combustion front [96].

The combustion front is characterized by the highest temperature—here, it reaches 370 °C and above. As the combustion front moves in the reservoir, several characteristic, distinct temperature zones are formed [100]. In the scorched region behind the combustion front, two temperature zones are distinguished. In the transition zone, the temperature changes from the temperature of the injected working agents (water and air) to the evaporation temperature of the injected water. Directly adjacent to the combustion front is a zone of superheated steam formed as a result of the evaporation of water injected together with air in the rock, heated to a high temperature by the combustion front moving ahead [101].

Heat transfer to the area ahead of the combustion front is carried out during wet combustion mainly by convective transfer by flows of evaporated injected water and combustion products, as well as by heat conduction. As a result, several temperature zones are formed ahead of the combustion front [102]. A zone directly adjacent to the combustion front has superheated steam, within which the temperature drops from the temperature of the combustion front to the temperature of condensation (evaporation) of the steam. The size of this zone is relatively small because heat losses in the rocks surrounding the reservoir led to rapid cooling of the gaseous water vapors filtered here and

combustion products, which are characterized by low heat capacity [103]. The main share of the heat transferred to the area ahead of the combustion front is concentrated in the zone of saturated steam—the zone of the steam plateau. There is heat loss to the surrounding rocks, accompanied by steam condensation in the transitional temperature zone. A hot water zone formed as a result of the complete condensation of saturated steam. The temperature in the saturated steam zone depends mainly on the level of reservoir pressure, taking into account the proportion of steam in the gas flow. Usually, within this zone, it varies insignificantly and is approximately 80–90% of the saturated vapor temperature [104]. The temperature in the transition zone varies from the steam condensation temperature to the initial reservoir temperature [105]. Usually, within this zone, it varies insignificantly and is approximately 80–90% of the saturated vapor temperature [104]. The temperature in the transition zone varies from the steam condensation temperature to the initial reservoir temperature. Usually, within this zone, it varies insignificantly and is approximately 80–90% of the saturated vapor temperature [104]. The temperature in the transition zone varies from the steam condensation temperature to the initial reservoir temperature [105]. Finally, in front of the transition zone, there is an area not covered by thermal action corresponding to the initial reservoir temperature. The size of the formation heating area ahead of the combustion front is largely determined by the rate of heat generation at the combustion front (and, consequently, by the rate of air injection) and the water–air factor [106]. An increase in the latter leads to the size increase of the formation heating area. If the process of wet combustion is carried out at the maximum possible value of the water–air factor or close to it, then almost all the heat accumulated in the reservoir will be located in the area ahead of the combustion front, and the size of this area will be maximum [107].

The distribution of the temperature field during wet combustion is mainly determined by the generation of steam at the combustion front and the heating of the reservoir area ahead of the combustion front by this steam [108]. Therefore, during wet combustion, the temperature situation ahead of the combustion front is in many respects similar to the temperature distribution during steam injection into the reservoir (Figure 13).

Thus, during wet combustion, the same oil displacement mechanisms will be implemented as during steam injection into the formation, namely, the mechanism of oil displacement by steam and hot water, the mechanism of miscible displacement by light oil fractions evaporated in the steam zone [109]. At the same time, since air and water are injected into the reservoir to implement *in situ* combustion, the mechanism of oil displacement by water–gas mixtures also manifests itself. In addition, the oil recovery process can be affected by the products of combustion and oxidation of oil in a porous medium, as well as by the physico-chemical transformations of the reservoir rock itself [110]. During combustion, a significant amount of carbon dioxide is formed, which creates conditions for the manifestation of the mechanism of oil displacement by carbon dioxide. This mechanism can be significantly enhanced in the case of the implementation of the process of *in situ* combustion in carbonate-type reservoirs due to the appearance of additional amounts of carbon dioxide due to the thermal and chemical decomposition of carbonates. Carbon dioxide, together with oil and water, can form foam, which has a positive effect on the oil displacement process [111]. During combustion, surface-active substances (surfactants), alcohols and other chemical compounds are also formed, which can cause the manifestation of the mechanism of oil displacement by emulsions [112], which has a positive effect on the oil displacement process [111].

Thus, during the implementation of *in situ* combustion, most of the currently known processes that increase oil recovery from reservoirs are manifested: gas, physico-chemical, and hydrodynamic. This explains the high rates of oil recovery observed during *in situ* combustion under laboratory and field conditions [113].

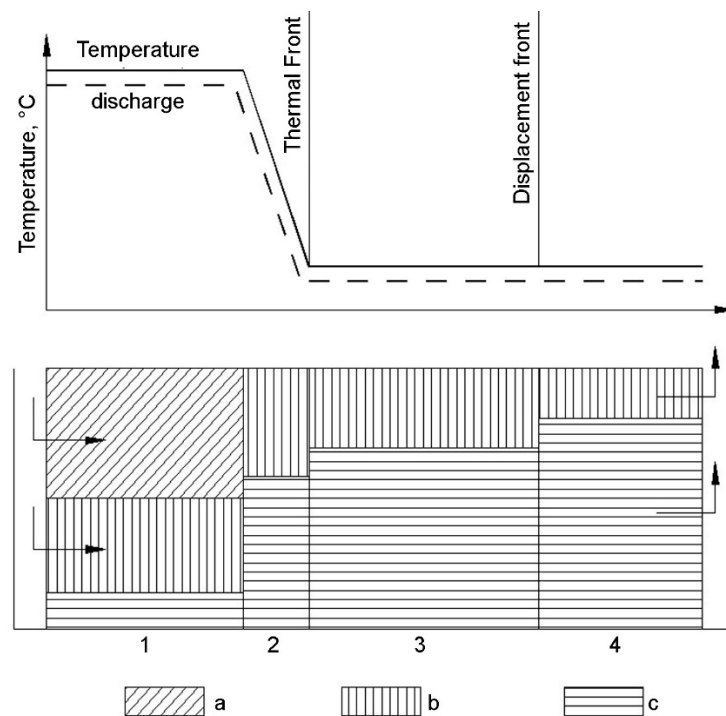


Figure 13. Scheme of oil displacement by steam: a—steam; b—water; c—oil. 1—saturated steam; 2—displacement of oil by hot water; 3—displacement of oil by water at reservoir temperature; 4—oil filtration under initial conditions [111].

The size of the formation heating area ahead of the combustion front during wet combustion is of the same order as the burnt zone and, in most cases, can reach 100–150 m or more. Therefore, on the one hand, it becomes possible to use the wet combustion method with relatively rare well placement patterns ($0.16\text{--}0.20\text{ km}^2/\text{well}$ and more), and on the other hand, there is no need to bring the combustion front to production wells, as a result of which air consumption for oil production is reduced [114]. Only due to the development of the formation heating area ahead of the combustion front the air consumption can be reduced 1.5–2.0 times. Additional savings in air consumption for oil production can be achieved by moving through the reservoir by injecting unheated water created as a result of wet combustion of the thermal rim. In general, it is believed that with wet combustion, the air consumption for oil production is reduced 2.5–3 times or more than when using dry combustion. A significant reduction in the cost of exposure to oil production during wet combustion is an important prerequisite for expanding the scope of thermal exposure to deeper layers [115].

The method of wet combustion is feasible for objects with a significant range of changes in geological and physical conditions. It becomes possible to develop oil fields of medium and low viscosity by this method, including after flooding [116].

With increased values of the water–air factor, varieties of combined technology arise based on a combination of waterflooding with in situ oxidative reactions. In this case, the combustion front, as well as adjacent zones of superheated steam, will cease to exist, and the injected air will enter the saturated steam zone, where it enters exothermic reactions with oil [117].

We note that the rate of oxidative processes is quite high, even at temperatures typical of the steam zone ($2000\text{ }^{\circ}\text{C}$ and above). This process is called ultra-moist combustion. In ultra-moist combustion, cold water invades the combustion zone even before the moment when all the oil remaining in the form of fuel is burned. In this case, heating and evaporation of water, heat recovery and its formation as a result of oxidative reactions are concentrated in a single zone. The rate of movement of water is determined by the rate of injection. Additionally, it will be significantly higher than the velocity of the combustion front [118].

The main disadvantages of oil displacement methods using in situ combustion include [119]:

- The need to apply measures for environmental protection and disposal of combustion products;
- The need to take measures to prevent corrosion of equipment;
- The possibility of manifestation of gravitational effects and, as a result, a decrease in the coverage of the formation by thermal exposure.

7.6. The Method of Thermal Gas Exposure

The method of thermal gas exposure (TGT) refers to thermal methods [120]. It is used in light oil fields with elevated temperatures above 650 °C and high reservoir pressures; similarly to in situ combustion, nitrogen, carbon dioxide, and light oil fractions act as displacing gaseous agents that mix with oil and provide an increase in its mobility. This contributes to an increase in the oil recovery factor, especially when developing deposits with hard-to-recover reserves [121].

The TGW technology was used in the pilot area of the Sredne-Nazymnskoye field, Yu0 reservoir, and Bazhenov formation [122]. According to the results of laboratory studies, the density of reservoir oil is 711–767 kg/m³; saturation pressure is 15.4 MPa, the reservoir pressure is $P_{pl} = 33.7$ MPa, and depth is 2720–2740 m. In well 219, the average water-to-air ratio varies from 0.0001–0.01. The cyclic nature of injection allows you to combine the properties of thermal and hydrodynamic effects on the formation. The volume of air injection is 24,000 thousand m³/day; water is 2.4–240 m³/day. At the mouth, the injection pressure of gas was 10–35 MPa, and that of water was 15–40 MPa. The total withdrawal of liquid from 4 producing wells, 401, 3000, 3001, and 3002, amounted to 150–400 m³/day. The thermal gas impact is recommended to apply to deposits with AHFP in bituminous reservoirs [122].

8. Other Methods of Enhanced Oil Recovery

8.1. Hydraulic Fracturing (HF)

One of the commonly used methods of enhanced oil recovery is hydraulic fracturing. Hydraulic fracturing technology and well development after hydraulic fracturing are discussed in detail in [123,124].

We consider the process of crack formation. It is known from continuum mechanics that in an elastic medium, a crack is formed in the plane of the highest normal stress, that is, in the plane in the direction of the rock stress [78]. Therefore, the crack is vertical. It propagates in the direction of the minimum normal stress, that is, in the direction radial from the well. Fracture opening occurs in the direction perpendicular to the well radius, Figure 14, $r = x$. A crack is a violation (rupture) of the continuity of the medium, in our case, the formation. The injection rate of the fracturing fluid is selected in such a way that the dynamic stresses that occur at the bottom hole exceed the tensile strength of the rock. To determine the technological parameters of hydraulic fracturing, mini-fracturing is carried out [125].

The choice of a good operation mode is determined by the results of hydrodynamic studies of wells after hydraulic fracturing. The performance of the ESP unit size should correspond to the good productivity factor determined after hydraulic fracturing [126].

The fracture created in the reservoir is filled with proppant, which does not allow it to close. Thus, a two-capacitive system formation–fracture is created in the reservoir. A fracture filled with proppant is a fictitious reservoir since the diameters of the proppant particles are the same [127].

When operating a well after hydraulic fracturing, the system “reservoir-fracture-well” is involved in the filtration. Through the side surfaces of the fracture, the fluid flows from the reservoir into the fracture. Then it moves along the fracture to the bottom of the well. The pressure in the fracture is distributed unevenly; the lowest pressure is at the bottom hole. Typically, a crack is modeled by two half-cracks, which is true only for a homogeneous

medium (Figure 14). The volumetric fluid inflow through the side surfaces of the crack is defined as [128].

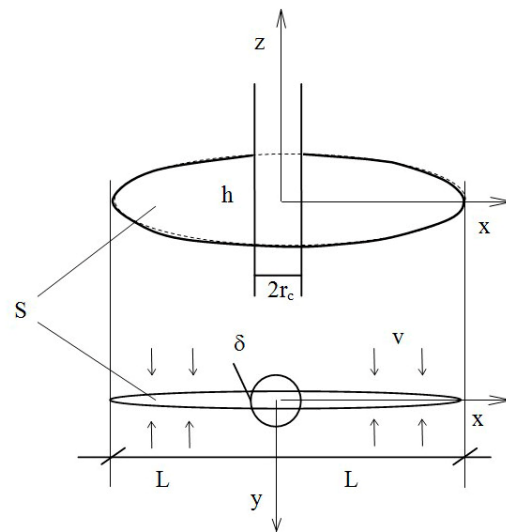


Figure 14. Hydraulic fracturing method with the scheme of oil displacement by steam: h is the fracture height at the bottom of the well, δ is the fracture opening at the bottom, L is the length of the half-crack, S is the area of the lateral surface of the half-fracture, v is the rate of fluid filtration from the reservoir into the fracture [125].

Thus, according to the parameters of the filtration parameters of the reservoir and the viscosity of the fluid, the optimal drawdown on the reservoir and the pressure at the pump intake are determined. Features of good operation after hydraulic fracturing in complex reservoirs are considered in [129–131].

Let us note that in the general case, not the entire side surface of the crack is a filtration surface. The presence of clay interlayers that are not identified by geophysical studies can significantly reduce the filtration area and, consequently, the well flow rate [132].

8.2. Operation of Wells with Horizontal Completion

The development of engineering, technology and new scientific methods in drilling contributed to the construction and operation of horizontal wells [133]. In the literature, an incorrect definition of such wells is used: horizontal wells (HW), implying that only the horizontal part of the well that has penetrated the productive formation is in operation. A large number of works have been devoted to determining the mining capabilities of HS. There are several hydrodynamic models that describe the flow of fluid from the reservoir to the horizontal part of the well, the length of which can reach 600 m or more. As a rule, horizontal wells are used to extract oil from low-permeability differences that are not involved in development [16,94,134].

Let us consider the main thing: why is the flow rate of a well with a horizontal ending greater than that of a deviated or vertical well? It follows from Darcy's law [40] that the flow rate is equal to the filtration area multiplied by the filtration rate.

$$q = vS = S \frac{k}{\mu} \text{grad} p \quad (10)$$

where q is the good flow rate, S is the HW filtration area, $\frac{k}{\mu}$ is the mobility coefficient, and $\text{grad} p$ is the pressure gradient. The area of HS filtration is equal to the area of the lateral surface of the cylinder, the product of the length of the horizontal part L and the circumference of the radius r_c :

$$q = 2\pi r_c L \frac{k}{\mu} \text{grad} p \quad (11)$$

Thus, the flow rate of the HW is obviously greater than the flow rate of a vertical well at the same pressure gradients and mobility factors. From (16), it follows that the flow rate of a horizontal well depends significantly on the length of the horizontal part. Since the large one can reach several hundred meters, at first glance, the flow rate of a horizontal well should be many times higher than the flow rate of a vertical or deviated well. However, not every length L is working [135]. The formations penetrated by the horizontal wells are heterogeneous and anisotropic; there are clayey impermeable interlayers. Consequently, the geological structure of the reservoir and its physical properties significantly affect the production rate. To determine the yielding zones and areas exposed by the horizontal wells, geophysical studies are carried out, according to which the yielding intervals are distinguished. The effect of anisotropy is considered in [115,136].

To increase oil recovery in horizontal wells, hydraulic fracturing is carried out. There may be several intervals scheduled for hydraulic fracturing, depending on the design of the horizontal well completion. In addition, chemical treatments of the BFZ are also carried out in the HS [137]. So far, in practice, hydrodynamic EOR is not used in HS, although the prospects look tempting.

8.3. Acoustic Methods

According to the technology of their use, acoustic methods can be divided into MIP and EOR. The former has an impact on the bottom hole zone, improving reservoir properties and well productivity. The latter affects the element, part of the production facility, involving the development of uncovered areas and capillary-retained oil [138]. Recently, the development of technology has allowed various technologies to aim at the development and improvement of acoustic methods of influencing the BFZ. In this section, the authors consider two of today's most popular technologies related to MIP: ARSiP and RCD [139].

The technology of acoustic rehabilitation of wells and formations (ARSIP) allows for improving the filtration properties of low-permeability oil-saturated interlayers of production and increasing the injectivity of injection wells [140].

An acoustic wave is an oscillation of tensile and compressive pressure of a given frequency. Moreover, the acoustic pressure gradient exceeds the stationary gradient used in the practice of oil production. As a result, there are forces applied to the fluid, which contribute to an increase in filtration in the BFZ [141].

The mechanism of the impact of an acoustic field on an oil reservoir is described in [142–144]. Under the influence of a longitudinal wave, the liquid tends to move in the direction of pressure drop, flowing into neighboring pores, while the shear stresses of the solid skeleton of the reservoir impart torque to the liquid.

It is known that most reservoir fluids, which behave like Newtonian fluids in volume, exhibit viscoplastic properties when moving in low-permeability reservoirs, characterized by plastic viscosity and structural strength, which depends on the ultimate shear stress [90,124,145]. The smaller the diameter of the pore channel, the greater the force must be applied to the fluid to entrain it in motion. As a result, at a certain ratio of the size of the pore channel and the current pressure gradient in the reservoir, complete or partial “locking” of oil occurs, and under the existing parameters of the development, oil remains unextracted [146].

The main task of injection well treatment was to redistribute (change) the injectivity profile in such a way that, according to geophysical surveys, it was noted that water was predominantly injected into the interlayers lying in the bottom part of the perforated productive horizon, and, as a result, insufficient coverage of the interlayers lying in the roof parts of the layer. A typical example of an uneven injectivity profile is the profile of injection wells 377/4 of the Kustovoye field. After carrying out work on the ARSiP technology, the injectivity profile increased significantly [147].

Method of ultrasonic processing (UZO) PZP. Works on PPP processing are given in [148]. The use of ultrasonic impact on the PZP with a frequency of 15–59 kHz allows:

- Reducing the surface tension at the boundaries of the solid phase and the fluid under the influence of vibrational energy generated in the elastic field by ultrasound;

- Changing the physical and mechanical properties of high-viscosity fluids containing asphalt and resinous compounds to make them more mobile;
- Involving interlayers with low filtration properties in the development, thereby increasing the sweep coefficient in thickness. The tests carried out at the Samotlor field showed that, on average, the oil production rate increased from 3.5 to 7.8 tons/day and the productivity coefficient from 0.143 to 0.23 m³/(day atm) [31,32].

The advantages of the UZO method are short processing time (average processing time for one well is about 15 h), the use of mobile small-sized equipment, low processing costs, and maintaining the integrity of the production string and cement sheath. This is a technically, physiologically and environmentally safe exposure process; the success of processing, with the correct selection of wells, reaches 80%; the duration of the effect is from 3 to 12 months [149].

Thus, the prospects of using acoustic methods to increase the productivity of production wells and the injectivity of injection wells are confirmed by field tests. The scope of these methods is quite wide and covers both low-permeability reservoirs and deposits with high-viscosity oil. It should be noted that acoustic methods for processing the BFR are compatible with other SCR methods [150,151].

9. World Experience in Using MIP and EOR

In this section, we have formulated the existence of a clear classification of methods for oil production and enhanced oil recovery—MIP and EOR. This classification is based on physical principles and approaches to in situ oil production processes [152,153]. Therefore, it is difficult to agree with many modern publications in which these principles are rejected and, for example, horizontal wells with multi-stage hydraulic fracturing are classified as basic EOR.

As it was presented, in the modern world, often all geological and technical measures (GTO) at wells can be attributed to EOR [154].

After analyzing a number of publications [155–157], the authors came to the conclusion that today only, less than 5% of the world's oil production is accounted for by projects to increase oil recovery by tertiary methods. At the same time, EOR is one of the methods of oil production that increases the productivity of oil wells. It is carried out with artificial maintenance of reservoir energy or artificial change in the physical and chemical properties of oil [158]. Annual production through the use of such methods in the world is estimated at about 150 million tons. Additionally, with the help of EOR, you can obtain much more, hundreds of billions of barrels of oil [159].

As described in detail above, EOR traditionally includes thermal, gas, physico-chemical (or simply chemical) and other (experimental, not reached the industrial stage of application) technologies—microbiological, wave, electrical, etc. [160,161].

The same can be said about the injection of hydrocarbon gases, which is EOR only in cases of targeted oil displacement through the reservoir, and the usual injection into the gas cap through single wells to maintain reservoir pressure or utilize excess associated gas has always been a secondary development method, which is quite natural from physical principles [162].

The global enhanced oil recovery market size was valued at USD 38.83 billion in 2021 and is expected to expand at a compound annual growth rate (CAGR) of 7.8% from 2022 to 2030 (GVR Report Cover Enhanced Oil Recovery Market Size, Share & Trends Analysis Report by Technology (Thermal, CO₂ Injection, Chemical), By Application (Onshore, Off-shore), By Region, And Segment Forecasts, 2022–2030) is shown on Figure 15. An increasing number of aged wells, along with decreasing production from existing oilfields, is expected to drive the market demand over the forecast period.

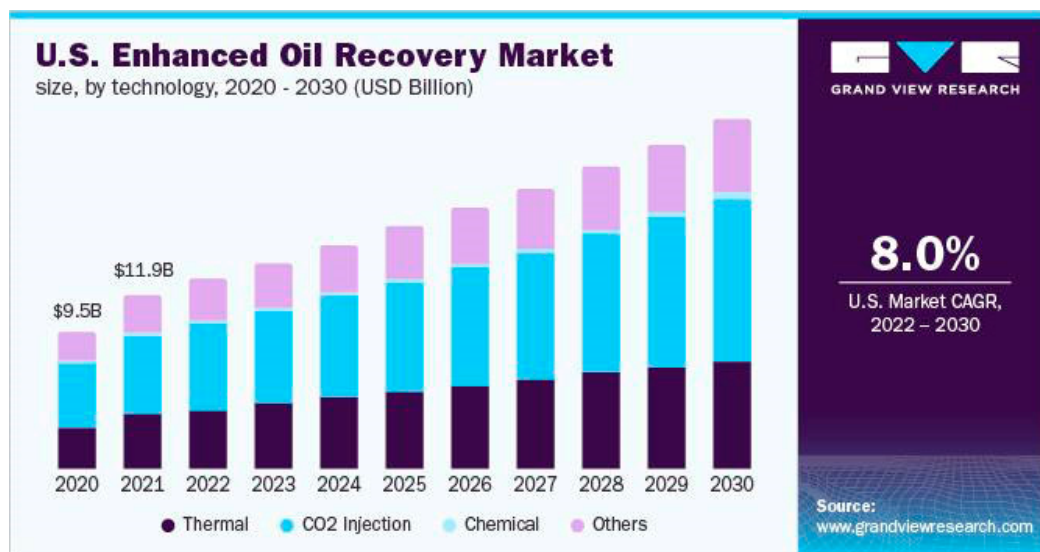


Figure 15. The global enhanced oil recovery market 2020–2030.

Enhanced oil recovery (EOR) technology enhances oil production from mature and aged oil fields by almost 10 to 20 percent when compared to conventional oil extraction methods. Mature wells are those oil reserves where production has reached its peak and have started to decline to owe to poor permeability or exhibiting heavy oil. Technically, EOR increases the permeability of the reservoir so that hydrocarbons can flow through the pathways easily and into the targeting-producing well.

Today, such boundary definitions have become vague, largely due to opportunistic considerations, and many authors allow free terminology and definitions. For this reason (different positions towards the EOR classification), different statistical sources contain radically different data on the number of EOR projects and the volume of oil production in them [163].

It should also be noted when studying the data on EOR projects that in many cases today, all oil production in the area of the EOR project is related to the EOR effect, which overestimates the result and is clearly unreasonable since the comparison should be made with the comparison base (option without EOR) [164].

The very number of projects in the world today is estimated approximately and with great discrepancies. Summarizing sources that are trustworthy, it can be argued that the number of EOR projects in the historical period has significantly decreased. The peak was in the eighties when there were about 700 of them (data from Shell) [165]. It seems that the most objective is the conservative assessment of global EOR projects (Figure 16).

In general, it can be stated that the general trend is an increase in the share of EOR gas projects, moreover, due to the use of carbon dioxide injection technologies while reducing projects for the injection of other gases [166]. At the same time, almost all growth was provided by the development of CO₂ projects in the USA, the number of which reached 133. In general, it should be noted that the share of EOR projects in the USA (about 220) is exceptionally large and amounts to 60% of the global number of operating EORs in the world [167].

Differences in estimates of the number of EOR projects are primarily associated with different approaches to projects for the production of heavy (heavy oil) and extra-heavy (extra-heavy oil) oil, as well as with the allocation of production due to thermal technologies from all heavy oil production in the project (often all production, including the stage of “cold” production by horizontal wells, is attributed to EOR) [168]. This approach, in our opinion, is more objective and correct since, in most cases, these are not tertiary EOR but primary methods for the production of extra heavy oil and bitumen, and they should belong to a separate category of reserves and technologies for their development [169].

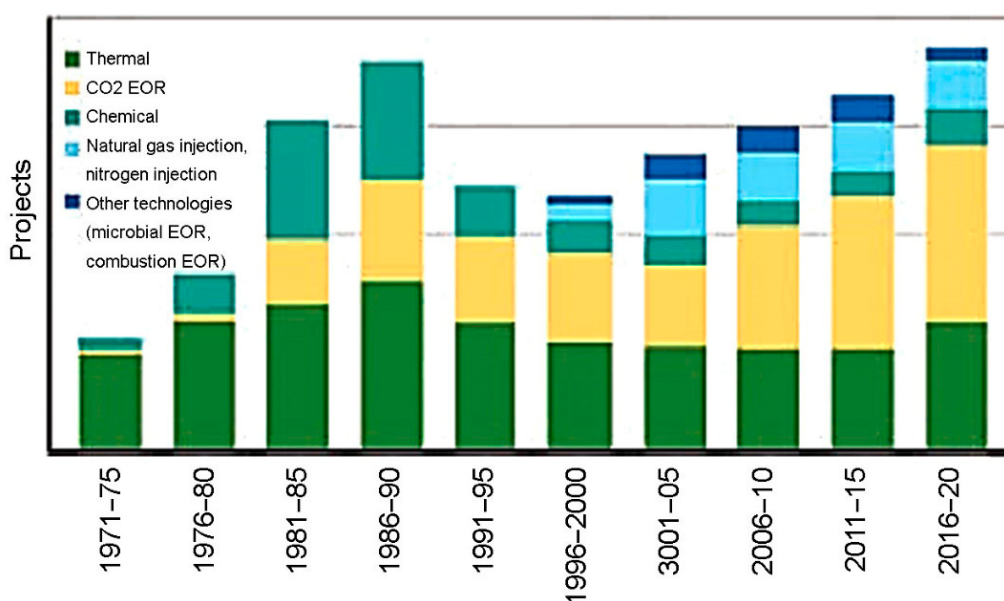


Figure 16. IEA evaluation of global EOR projects [165].

A conservative assessment implies the exclusion of projects with extra-viscous oil (density less than 10° API, which is directly indicated in the primary sources of publications), considering them as a separate category of hydrocarbons together with bitumen, more strict consideration of additional production in projects of heavy oil and gas methods [170]. It should be noted here that in the United States, throughout the entire historical period, conservative estimates in EOR production have been consistently used [171].

It can be stated that EOR, despite the huge production potential and all previously made forecasts, has not become an important factor in the development of world production, remaining an auxiliary source. At the same time, in a number of countries—the USA, Canada, Venezuela, China, and Oman—EOR play a significant role [172].

A conservative summary of production data by different EOR groups is presented in Table 1.

Table 1. Annual Oil Production with EOR.

Years	1984	1994–2000	2006–2010	2014–2018
Annual production according to EOR estimate, mln t, of which:	56.1	93–103	101–94	94–88
Thermal EOR	35.4	51–60	40–52	36–49
Gas EOR	18.7	25–33	25–33	27–32
Chemical and other EOR	2	2.4–4	11–12	14–17

The share distribution of oil production volumes due to different EOR groups differs from the structure of the number of EOR projects; thermal EOR continues to play the first role, although there is a downward trend [173]. The share of production through chemical technologies is growing noticeably, reaching 17–19%, significantly exceeding their weight share in the number of projects. This is due to the large-scale implementation of polymer and ASP flooding in China [174]. Production volumes due to gas EOR are not growing. The increase in production due to CO₂ is offset by a decrease in production due to other gas EORs, primarily due to the lack of large new projects [175].

In technological terms, the unrealized potential of EOR in all oil-producing countries is large. However, the general situation with EOR in the world indicates that in the context of globalization of the economy, and even more so at the time of the transformation of the world economy (multi-vector development of the fuel and energy complex, “energy turn”),

EOR has no real prospects for large-scale development. First of all, due to large initial capital investments and long payback periods for projects, moreover, with increased technological risks of errors in forecasting the achieved levels of oil production. Statements about the need for special economic mechanisms for the implementation of EOR technologies have become commonplace. However, specific and effective solutions have not been developed or adopted in almost any country in the world today, perhaps with the exception of China [176].

It is also important to note that over the past thirty years, there have been no fundamental successes in the development of EOR technologies in the world. All technological foundations of EOR are known, and it can be argued that there is only some modernizing development of them “in breadth” towards an evolutionary expansion of the conditions of applicability in terms of temperature and permeability of the formation, in terms of salinity of formation water. This is determined by the immutability of the scientific foundations of EOR and the lack of new fundamental research on capillary—chemical and rheological—in situ processes of oil displacement.

Over the past thirty years, there has been no fundamental development in EOR technologies. All technological foundations of EOR are known, and it can be argued that there is only some modernizing development of them “in breadth”, towards an evolutionary expansion of the conditions of applicability in terms of temperature and permeability of the formation, in terms of salinity of formation water.

As can be seen from the graph, about 60% of known EOR technologies are still insufficiently studied for reasonable and large-scale commercial applications. Additionally, among those noted as a high level of readiness, such technologies as polymer flooding and especially flooding of “low salinity” cannot be considered well studied.

Modern trends in digitalization, smart wells, and smart and digital fields are mainly focused on big data mathematical algorithms (in fact, long-known methods of mathematical statistics, enhanced today by computer capabilities). Inadmissibly little attention is paid to the physical chemistry of the processes that determine the efficiency of oil displacement and, ultimately, oil recovery. The lack of large-scale statistical studies, generalizations of field development experience and identification of factors that determine the achieved oil recovery factor depending on geological and physical conditions have become an urgent problem in world practice, although modern computerization allows this to be performed at a higher level. The reason is clear—the disunity of oil and gas companies and the hypertrophied understanding of trade secrets are often associated with the need to exaggerate the real state of affairs in terms of achieving design oil recovery factors for specific fields [177].

According to the analysis, the openness and availability of geological and field information in many countries are increasing, which allows the scientific community to perform qualified analysis, including through independent examination by scientists and university graduate students.

A new “danger” for the future of EOR may be a “digital core”; a relevant and promising direction, but under one condition that is not fulfilled today. Today there is nothing to fill and saturate this digital model with except for outdated research data and approaches (there is no data for three-phase filtration of real oil and gas mixtures, and not primitive “oil models” from yesterday; there is not enough data and theory about the rheology of reservoir systems in a porous medium; no geochemical data processes that accompany real long-term filtration of water in a porous medium; there are no sufficient data on electrokinetic and capillary phenomena, energy competition of surface interactions of oil and a displacing agent; there are no data and a full-fledged capillary—chemical theory of oil and water filtration under conditions of real reservoir wettability with a transfer methodology to the scale of the entire reservoir and much more). The creation and use of digital cores without such data, based on “old scientific baggage”, will inevitably lead to erroneous technological solutions and developments that further undermine the investment attractiveness of EOR [178].

Regarding the future of EOR, it can be stated that at present conservative, cautious forecasts prevail in the world, and the intensive development of EOR is regularly pushed further today—beyond the horizon of 2025. So, for example, if IEA in 2006 predicted EOR production by 2030—35 million barrels per day or 22% of global oil production, then in 2009, it was already only 6 million barrels per day (Figure 17).

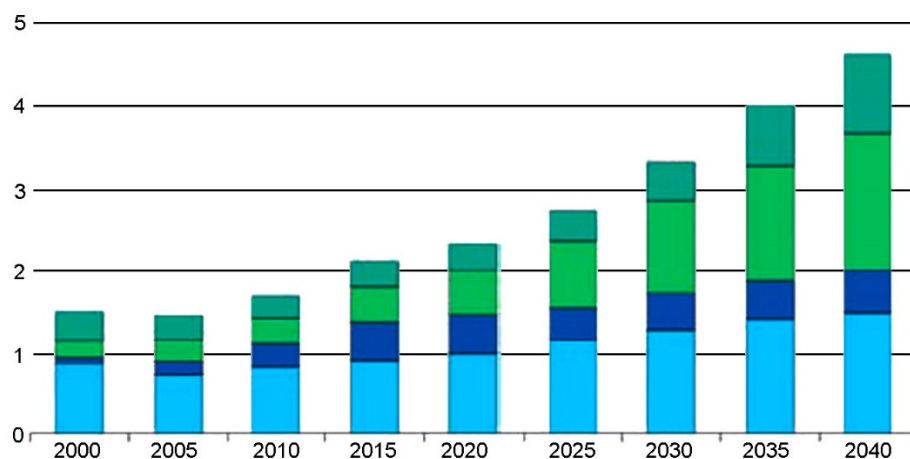


Figure 17. Dynamics of actual (until 2015 inclusive) and predicted EOR oil production in the world, million barrels per day IEA2018. Designations sequentially from bottom to top: thermal, chemical, CO₂ and other gas EOR [178].

The lack of large-scale statistical studies, generalizations of field development experience and identification of factors that determine the achieved oil recovery factor depending on geological and physical conditions has become an urgent problem in world practice, although modern computerization allows this to be performed at a higher level [179].

The level of oil production achieved today in the world due to tertiary EOR can be estimated at the level of only 2–3% of the total oil production. The world continues to be dominated by the policy of postponing EOR “for later”, after the selection of the main oil reserves, with the condition of continuous expectation of high oil prices, forgetting (or not taking into account) the periodically occurring but passing oil price crises.

Regarding the future of EOR, it can be stated that currently, conservatively cautious forecasts prevail in the world; the intensive development of EOR is regularly pushed further and further.

One cannot but agree with Shell [180], who is confident in need to change the conceptual approaches to EOR, that one should not think of EOR as a simple addition to traditional methods of production, something that can be considered later in the life of the field for recovery of falling production. The use of EOR must be taken into account from the very beginning of the life of the field.

As a positive trend, we can note the emergence of a new term, “EOR 2 + 3”, which we met in the annual report of the Chinese company CNPC, which means the recommendation to apply EOR as early as possible, simultaneously with secondary development methods. EOR should be less and correspond less to their original definition as tertiary mining methods and more as high-tech technologies [181].

In matters of classification and analysis of EOR technologies, the task of more rigorous systematization of technologies and projects for the effective development of hard-to-recover hydrocarbon reserves has become relevant. In modern professional literature, in our opinion, the correct trend has been to separate (systematize) technologies not only according to the physical principle of operation (thermal, gas or chemical) but also according to the conditions of applicability (separate categorization for traditional oil, including heavy oil, and separately for extra-viscous and bitumen or for “shale oil” reserves-ultra-low-

permeability “semi-reservoirs”). Moreover, for super viscous oils and bitumens, thermal EOR is rather not a tertiary but a primary development method.

EOR should be less and correspond less to its original definition as tertiary mining methods and more as high-tech technologies [182–184].

10. Discussion

It is possible to make the generalizing conclusions that the potential possibilities of enhanced oil recovery by various methods in the world are as follows: thermal methods-15–30%, gas methods-5–15%, chemical-25–35%, physical-9–12%, hydrodynamic-7–15%. However, production costs of oil and gas production are constantly growing; at the same time, oil prices are dropping, which leads to the fact that the economic attractiveness of EOR methods is decreasing. At the same time, the application of modern methods of oil recovery enhancement of reservoirs results in an average oil recovery factor of 30–70%, out of which 20–25% is achieved by primary methods of development (using reservoir energy potential) and 25–35%—by secondary methods (waterflooding and gas injection for reservoir energy maintenance). Physico-chemical methods allow us to determine the low content of components in the analyzed objects. They reduced the detection limit to 10–5–10–10% (depending on the method of analysis). Chemical methods of analysis (titrimetric and gravimetric) do not allow the detection of such quantities of a determinable component. Their detection limit is 10–3%. Physico-chemical methods allow you to carry out the analysis quickly enough. The rapidity of these methods makes it possible to adjust the technological process. Instrumental methods of analysis allow to automate the process of analysis, and some devices allow to carry out the analysis at a distance. It is possible to carry out the analysis by means of physical and chemical methods without destroying the analyzed sample at a certain point. The advantage of physico-chemical methods of analysis is the use of computers both for calculating the results of analysis and for solving other analytical issues. The disadvantages of the physical-chemical methods of analysis are that the error of analysis is 2–5%, which is higher than the error of classical chemical methods. Physico-chemical methods require expensive instruments, standards and standard solutions.

The advantages of thermal EOR are the reduction of viscosity of water and oil; they are practically the only alternative method for bitumens and high-viscosity oils. The disadvantages are high capital intensity due to the high cost of special equipment and the need to use a fairly dense screen of wells, which is inefficient at large depths of the formation. The disadvantages are:

- The short duration of the effect;
- The probability of failure to achieve the planned effect of treatment;
- The High cost of chemical reagents.

Hydrodynamic EOR has a lot of advantages: reduction of volume of water pumped through the reservoir; reduction of water cut of produced fluid; easy implementation; applicability in a wide range of reservoir conditions; high economic and technological efficiency; lack of high economic costs for implementation. Disadvantages: temporary reduction of flow rate by responding wells (due to stoppage of influencing injection wells); probability of not achieving the planned effect when implementing the measure. The advantages of gas methods are as follows: application of inexpensive agent—air; use of natural reservoir energy-increased reservoir temperature (over 60–70 degrees Celsius) for spontaneous initiation of reservoir oxidation processes and formation of the highly efficient displacing agent. An important condition for the effective application of enhanced oil recovery methods is the correct choice of an object for a method or, on the contrary, a method for an object. Criteria of methods applicability define the range of favorable fluid and reservoir properties, under which effective application of a method or obtaining the best technical and economic indicators of development is possible. These criteria are defined on the basis of analysis of technical and economic indicators of method application, generalization of experience of its application in various geological and physical conditions,

as well as the use of extensive theoretical and laboratory research. Usually, there are three categories of method applicability criteria: Geological and physical (properties of formation fluids, depth of occurrence and thickness of oil-saturated reservoir), parameters and features of the oil-bearing reservoir (saturation of pore space with formation fluids, conditions of occurrence) and others; Technological (size of the rim, the concentration of agents in solution, placement of wells, injection pressure, etc. The first category of criteria is determinative, the most important and independent. Technological criteria depend on geological-physical criteria and are selected in accordance with them.

Material and technical conditions, for the most part, are also independent, remain unchanged and determine the possibility of meeting the technological criteria. Thermal EOR is mainly used in the production of highly viscous paraffinic and resinous oils; chemical methods are used in reservoirs with low oil viscosity (not more than 10 mPa·s), low water salinity, productive formations are represented by carbonate reservoirs with low permeability. Hydrodynamic methods of oil recovery enhancement function inside the development system, more often when oil reservoirs are flooded, and are aimed at further intensification of natural processes of oil recovery. Gas EOR methods are applied in impermeable reservoirs, highly watered and deep formations with viscous oil, in under-gas zones. Thus, the methods of oil recovery enhancement increase the recoverable world oil reserves by 1.5 times, which is up to 65 billion tons. According to experts, the use of modern methods of oil recovery enhancement leads to a significant increase in the oil recovery factor. Additionally, its increase, for example, only by 1% in the world will allow it to produce more than 60 million tons per year additionally. Consequently, we can state that the demand for modern EOR methods is increasing, and their potential to increase the recoverable reserves is impressive.

11. Conclusions

Thus, we have considered the main methods and technologies currently used for the development of oil fields. As can be seen from the presented review, the choice of a development system, placement and selection of a good operation mode significantly depend on the geological structure of the reservoir, its volume and the properties of oils.

In international practice, the role of reproduction of the raw material base of oil production through the introduction of modern methods of enhanced oil recovery (thermal, gas, chemical, microbiological) based on innovative techniques and technologies is growing rapidly and becoming more and more a priority.

Currently, the priority direction for the growth of oil reserves in world oil production is the development and industrial application of modern integrated methods for enhanced oil recovery (EOR), which are able to provide a synergistic effect in the development of new and developed oil fields.

It should be noted that the construction of a geological model of a production facility plays an important role in this. The hydrodynamic development models used are based on physical laws, which oil producers sometimes do not even suspect, and the authors of the models cannot always convey this to real producers. Each model has its own scope, and what is suitable for one object may not correspond to another. As you can see, there is no universal way to develop an oil deposit. Additionally, it is necessary to choose it after a thorough feasibility study among several proposed models. This will be the subject of a separate article by the authors.

When describing the methods of enhanced oil recovery, special attention is also paid to the physical processes that take place as a result of the technology. What happens in a real reservoir when it is affected by injected reagents, a change in the operating mode, or a violation of the initial reservoir properties? Their change over time can be predicted and predicted. The main methods and technologies for enhanced oil recovery were developed in the middle of the 20th century. Their use at that time was limited by the imperfection of the necessary technical means and materials. However, the physical processes occurring in a porous or fractured medium have not changed. Their description, the boundaries of

the scope and the possibility of achieving the ultimate goal, namely, enhanced oil recovery, were clarified.

Prospects of oil recovery enhancement methods can be concretized in the following points:

1. The transition from rigid methods of influence on stratum for receiving big volumes in short terms to regimes sparing the internal system of a field promotes prolongation of operation of a field and, accordingly, increase in the volume of produced oil. The application of the suggested methods of oil recovery increase will allow using fields at the final stage of development and those which can still give big flow rates for many years with maximum efficiency.
2. Application of one method is not enough for more effective development of a deposit; application of a complex of methods ensures maximum oil recovery factor. It is necessary to understand that the mode of deposit changes with the time of operation of a field, as well as production conditions should change. Oil field works must mean not only the development of reserves with the aim of getting a quick income but also professional field development, research of the maximum possible quantity of hydrocarbons, preservation of the environment and the deposit's internal system [2].
3. Cooperation between the state and oil-producing companies is an integral part of a successful oil-producing complex. First, it is necessary to think about the perspective of the decisions made, about the responsibility for the conduct of development and reasonable exploitation of the field.
4. Expanded the conceptual and categorical apparatus related to the predictive evaluation of the results of measures to improve oil recovery and to form a comprehensive methodological approach to the planning of these activities.
5. Proposed the use of combined activities to improve oil recovery, maximizing the amount of additional oil production.

The practical significance of the developed proposals lies in the fact that they form the basis for practically acceptable tools for assessing methods of improving oil recovery in the late stages of field development. In particular, the proposed approaches allow choosing the most effective ones for oil and gas producing companies: in conditions of significant variation of geological and field, parameters increase the possibility of forecasting oil production increment due to oil recovery enhancement methods, thereby reducing the cost of oil production at acceptable risk level.

The authors consider it appropriate to make a logical generalizing conclusion that understanding the processes occurring in the reservoir and taking appropriate measures to optimize and intensify oil production will save millions of tons of oil.

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