LECTURE 7
GAS, THERMAL AND MINE RECOVERY METHODS
GAS RECOVERY METHODS

1. Usage of dry hydrocarbon gas

Injection of gas into oil reservoir for the purpose of MFP and enhanced oil recovery was used much earlier than waterflooding. Air, exhaust or flue gas, hydrocarbon gas were used for this purpose. The usage of air has been discontinued due to many negative consequences (oxidation of oil in the reservoir, increase of its density and viscosity, decrease of commodity quality of oil gas, formation of stable water-oil emulsions, etc.). In the case of the use of liquefied hydrocarbon gases, as well as other liquid hydrocarbon solvents, there is a new and equally difficult problem of extraction expensive solvent from the bowels trapped in the pores, whose price is much higher than oil.

Nowadays, they are limited to the use of hydrocarbon dry gas, gas mixture, high pressure gas and enriched gas. Oil displacement can be both unmixed and mixed (without the avalibility of phase separation boundary). Miscibility of gas with reservoir oil under modern technical conditions is achieved only in the case of light crude oil (gas density less than 800 kg/m^3) at an injection pressure of dry hydrocarbon gas near or over 25 MPa, enriched gas - 15 ... 20 MPa (for comparison: liquefied gas - 8 ... 10 MPa). With improving displacement, oil recovery increases.

The usage of hydrocarbon gas was determined by difficulties or negative effects of water injection (the presence in the reservoir of swelling in water clay; low permeabil rocks and, as a consequence, insufficient acceptability of injection wells).

The main criteria for the efficiency of gas injection are the following:

a) The bedding angles: the angles over 15° gas injection is carried out into the attic zone, the smaller - pattern drive (in gently sloping structures gravitational separation of oil and gas is hinded);

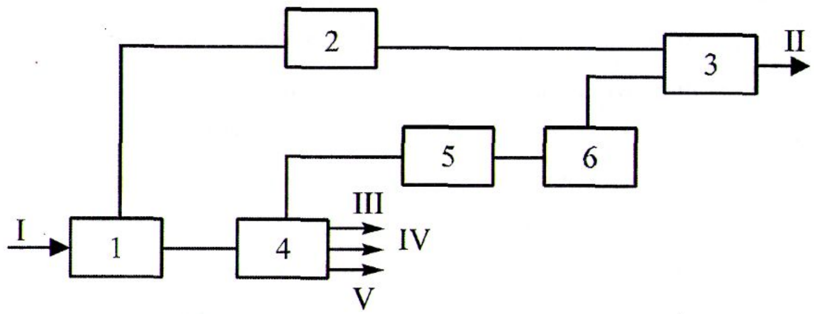
b) the depth of the layers bedding: the low depths and high injection pressures gas breakthroughs into upper layers are possible, and at greater depth it is necessary to secure high injection pressure by compressors that is not always feasible and economically justified;

c) layer permeability uniformity and low oil viscosity: permeability and viscosity displacement instability are manifested and premature gas breakthrough into production wells occurs;

d) hydrodynamic isolation of the reservoir that ensures no oil flow out from the deposits.

Oil gas, natural gas from adjacent gas fields, or gas from main gas pipelines can be used for injection into the reservoir.

The flow diagram of the injection and preparation of dry petroleum gas is shown in Figure 7.1.



I – production from oil wells; II – gas into injection wells; III – gas for local consumption; IV – oil for consumpotion; V - water;

1 – high-pressure separator; 2 – gas separator; 3 -compressor; 4 – oil treatment plant; 5 – gas plant; 6 – low-pressure compressor

Figure 7.1 – Technological scheme of dry hydrocarbon gas injection and treatment

Acceptance of wells is established experimentally or estimated by the gas well flow formula, multiplying the calculated value by the experimental coefficient. To maintain pressure at the existing level, the total discharge gas flow must be equal to the sum of the oil, gas, and water flow rates, which are reduced to reservoir conditions. By dividing the total cost of acceptance of one well, you can determine the number of gas injection wells. The downhole pressure is calculated taking into account the loss of friction pressure and pressure of the gas column. Typically, the discharge pressure is 15-20% higher than the reservoir pressure.

2. *High-pressure gas injection*

In case of oil displacement by high-pressure dry gas (only methane practically) in conditions that provide mutual fluids miscibility in the reservoir miscible zone is formed as a result of (C_2 - C_4) components mass transfer from oil (where their content is greater) into the gas phase. This is achieved in the result of dry gas penetration in the reservoir zone that are saturated by oil. Flowing through layers and repeatedly contacting with the oil, gas becomes enriched by intermediate components that their concentration reaches an equilibrium value. In the case of appropriate thermal dynamic conditions enriched gas and oil form a critical mixture, i.e full mutual miscibility.

Application of this method is useful primarily for light oil reservoirs (density 850 kg/m^3) that lie at great depths and are associated with low permeable reservoirs, which can create high pressures required to achieve conditions of full mutual oil and gas miscibility.

3. *Enriched gas and LPG usage*

For layers that occur about 1500 m, with a relatively heavy oil gas with relatively high enough content (volume fraction of

30% or more) of intermediate components (usually propane-butane fractions) are used .

In case of enriched gas injection into the formation miscible zone between oil and gas is formed due to the transfer of volatile components from gas into oil. Fluids miscibility is achieved at very low displacement pressures.

Thermodynamic miscibility conditions of specific oil investigated and determined mainly by experimental researches.

In case of liquefied hydrocarbon gases usage, which are mainly compose a basis of transition zone of these methods, only slug of the agent is injected into the reservoir. For liquefied gases slugs injection thermodynamic conditions in the field must be such as to ensure their liquid state.

4. *Non-hydrocarbon gases injection*

Over the past 20 - 30 years in the practice of oil field development being nitrogen and gaseous products of combustion mixtures of different gases. The economic calculations, experimental and practical experience are entitled to consider these agents not only acceptable, but also beneficial to the oil displacement.

As in the case of hydrocarbon gases and carbon dioxide usage, the process of displacement will be most effective in case of in-situ agents mutual miscibility. The differences are determined by the different values of the pressure at which this process occurs.

Carbon dioxide usage

One of the widely used methods is the displacement of oil by injection of carbon dioxide (CO_2) into the reservoir. Carbon dioxide injection to increase oil recovery began to be used in the mid-fifties. During this time the mechanisms of physicochemical interaction of carbon dioxide with water, oil and rock were studied; features of oil displacement using carbon dioxide are determined; advantages and disadvantages of other methods of increasing oil recovery are considered. Unlike other gases, using CO_2 as a displacement agent a significant increase in the oil recovery factor can be achived. In laboratory conditions, with unlimited miscibility, the oil displacement coefficient can reach 100%.

In many ways, the productive effect of carbon dioxide injection technology is due to the fact that CO_2 is able to dissolve in oil and formation water to a greater extent than other gases. When dissolved in oil, carbon dioxide increases the volume of oil, which in turn contributes to the displacement of irreducible oil. On the basis of laboratory experiments it was found that with a mass content of 22.2% of CO_2 in oil, its volume ratio increases from 1.07 to 1.33. Carbon dioxide injection helps to reduce interfacial tension at the oil-water boundary. When dissolved in oil and water CO_2 improves the wettability of the rock with water, which leads to the washing of the oil film from the surface of the rock, transferring it from the film state into the droplet, thus increasing the displacement coefficient. The ability of carbon dioxide to dissolve in water allows part of the CO_2, which has better solubility in hydrocarbon liquids than in water, to convert into oil. When carbon dioxide is dissolved in water, the water viscosity increases slightly, but carbonic acid (H_2CO_3) is formed, which dissolves some types of cement and formation rock, increasing its permeability. According to the results of laboratory studies of BashNIPInaft, sandstone permeability can increase by 5-15% and dolomites by 6-75%. The more carbon dioxide contained in water, the more efficient the displacement of oil. The effect on the degree of solubility of carbon dioxide in water has a mineralization of water, with increasing the degree of mineralization decreases the solubility of CO_2 in water decreases.

Also an advantage of carbon dioxide injection is the ability to increase the mobility of oil. According to the laws of thermodynamics, at a high degree of oil expansion, part of the adsorption layer of oil in the pores is released, the viscosity under the influence of dissolved gas decreases, and oil becomes mobile. To a greater extent, this effect is manifested in the interaction with high-viscosity oils (more than 25 MPa · s). According to laboratory studies, the higher the initial value of viscosity, the greater its decrease (Table 7.1).

Table 7.1 – Changing the viscosity of oil when it is fully saturated with CO_2

The initial viscosity of the oil, мПа·с	Oil viscosity at full saturation CO_2, мПа·с
1000–9000	15–160
100–600	3–15
10–100	1–3
1–9	0,5–0,9

However, in practice, the viscosity of deposits using CO_2 injection does not reach such high values. According to the analysis of world projects concerning the injection of carbon dioxide, oil viscosity is in the range of 0.4-3.0 MPa·s.

Under reservoir conditions, depending on temperature and pressure, carbon dioxide may be in a gaseous, liquid, and supercritical state. The critical point is characterized by a temperature of 31.2 ° C and a pressure of 7.2 MPa. At temperatures below 31.2 ° C, carbon dioxide may be in the liquid phase. The temperature at which the carbon dioxide will be in the liquid state can raise to 40 ° C if the composition will contain hydrocarbons. At temperatures above 31.2 ° C, CO_2 will be in a gaseous state at any pressure. In the supercritical state, the density of carbon dioxide corresponds to the density of the liquid, and the viscosity and surface tension - to gas. In this state, CO_2 will displace oil with a decrease in the coverage of inhomogeneous layers, which is characteristic for a low viscosity agent.

It has been experimentally determined that it is more efficient to pump carbon dioxide in the liquid state, and the optimum formation temperature should be close to the critical value. The greatest effect in the displacement of oil by carbon dioxide is achieved by mixed displacement, which is possible at formation pressure above the pressure of miscibility.

Mixing pressure depends on the oil composition and saturation pressure. With increasing saturation pressure, as well as in the presence of methane or nitrogen in the composition of oil, the mixing pressure increases. High molecular weight hydrocarbon gases, including ethane, help reduce miscible pressures. The CO2 miscibility pressure is much lower than the hydrocarbon gas miscibility pressure. If the displacement of light oil by carbon dioxide, the miscibility pressure will be in the range of 9-10 MPa, then for the mixed displacement of hydrocarbon by gas it should be from 27 to 30 MPa. In the case when the pressure in the reservoir does not reach the miscibility pressure, the interaction of carbon dioxide with oil produces CO_2 with a light oil phase content and oil without light fractions.

The displacement of oil by carbon dioxide is a rather complicated process in which the effects of mass transfer, capillary and gravity are manifested. With partial or complete miscibility of carbon dioxide with oil, its rheological properties change, this contributes to the involvement of previously unused oils in the development. The process of oil displacement of oil by carbon dioxide is affected by saturation conditions and pre-displacement.

During the period of studying the technology of carbon dioxide injection into the reservoir in order to increase the oil recovery, different approaches to its application were distinguished:

- Carbonated water injection;
- continuous injection of CO_2;
- injection of the CO_2 slug with subsequent injection of water;
- Oil displacement alternates with CO_2 and water injection;
- the displacement of oil by the injection of combined boundaries of chemical reagents and CO_2.

The main advantage of pumping carbonated water is the relatively low consumption of carbon dioxide when pumped into the reservoir compared to other uses. The optimum concentration of carbon dioxide in water is 4-5%. During laboratory experiments in determining the efficiency of carbonated water use, it was found that the displacement of oil with carbonated water at concentration of CO_2 of 5.3% allows increasing oil recovery by 14% compared to the displacement by water.

The advantage of continuous carbon dioxide injection is to achieve a higher displacement rate than other technology applications. This is due to the fact that before the CO_2 is formed by an oil bank inherent in the processes that occur under mixed displacement. The disadvantages of continuous carbon dioxide injection can be attributed to viscosity instability, which in some cases can significantly reduce the coverage ratio and lead to early carbon dioxide breakthroughs.

Compared with continuous displacement by carbon dioxide, the version with alternating CO_2 and water injection is more economical on the account of reducing the volume and therefore the cost of carbon dioxide. Also, the advantages of alternating injection can be attributed to the fact that alternating injection of carbon dioxide and water can be effective for inhomogeneous layers, depending on the ratio of CO_2 to H_2O. The results of the laboratory experiments are cited in the literature, but it is also emphasized that the effectiveness of each particular project should be based on experimental experience in which the conditions were as close as possible to real conditions. There are different thoughts of experts relating to the carbon dioxide injection. When the results of laboratory experiments were published, as a result of which it was concluded that for a homogeneous formation with limited miscibility, the option of pumping a solid border would be a better option compared to alternating injection. It is also emphasized that alternating injection of carbon dioxide and water reduces the final oil displacement ratio as compared to continuous injection. According to the results of other experiments, it is determined that for a homogeneous formation alternating injection is effective, and the optimal volume of the slug is from 9 to 12% of the pore volume. According to the authors of this article, after the analysis of laboratory and field experiments, including in the Radayev field, as well as the study of scientific works on the subject, the effectiveness of alternating pumping technology was proved. And the application of this option will be effective for heterogeneous layers, although the degree of efficiency may be different.

With all the obvious advantages of using technology to increase oil recovery by pumping carbon dioxide, it has some disadvantages. Compared to flooding, CO_2 injection has a reduction in coverage efficiency. Alternative injection of water and carbon dioxide, as well as selective insulation, may be used to reduce this effect. In turn, the use of water successivly with CO_2 can lead to a significant complication, which is possible when carbon dioxide is pumped - corrosion of the equipment of injection and production wells. Another disadvantage of this technology is that with incomplete miscibility with oil, CO_2 extracts light hydrocarbons from it, and heavy fractions remain in the oil, resulting in the oil becoming immobile, and it will be much more difficult to recover it in the future.

Another disadvantage of this technology is that carbon dioxide refers to gases that, when saturated with their water vapor, can form crystalline hydrates.

In the process of dissolving CO_2 in water and oil, a decrease in temperature will be observed. The degree of decrease in temperature increases with increasing concentration of carbon dioxide. Such a temperature effect during carbon dioxide dissolution can affect the formation of asphaltene-tar-paraffin deposits.

According to some estimates of the investigated technology, if it is not possible to secure the supply of carbon dioxide at an affordable price within the required time, there is a high probability of losing the possibility of increasing the final oil extraction. Ensuring supply at a later date, when the deposit is at a later stage, and there is a decrease in reservoir pressure only unmixed displacement is available, the effect of which is several times lower than in mixed displacement. For some reservoirs such an estimate is quite justified. The lack of an available source is a significant limitation to the application of carbon dioxide injection technology. For many fields, producing and transporting CO_2 to a site it may not be economically viable.

According to 2014 data, 136 carbon dioxide injection projects are being implemented in the world by 30 operators. Of these, 88 are considered successful, 18 are related to remaining promising projects, 20 have recently started. Ten projects failed to be implemented effectively. Most of them, 128 out of 136, are being implemented in the USA. The latest carbon dioxide projects include projects started in 2014 at Slaughter (Smith Igoe), located in Texas, USA, and operated by the large US oil company Occidental. Despite the short term, the project is already considered to be successful, and the flow rate is 2.65 m3 / day / day. The CO_2 injection projects at Charlton 19 and Chester 16, located in Michigan, USA, developed by Core Energy, also began in 2014.

Nitrogen usage

Nitrogen is the preferred alternative to methane among hydrocarbon gases. Huge reserves of nitrogen are in the air, and the methods of obtaining it are quite simple, cheap and well-studied. Nitrogen has a low corrosive activity, which is very important for the smooth operation of downhole equipment. The physicochemical properties of N_2 are also well compatible with the properties of reservoir fluids. The disadvantages of using nitrogen are poor miscibility with oil, but using it with the right approach to development management is technologically and economically justified.

The possibility of using hydrocarbon gases to increase oil and condensate recovery has been actively considered by foreign oil and gas companies since the early 1970s. In industrial practice, nitrogen is used as:

- blowing agent when pumping portions of carbon dioxide, natural gas and other components with mixed displacement. CO_2 and natural gas are characterized by high oil displacement rates, but given their increasing cost and possible lack of required volumes, the use of additional volumes of nitrogen is considered an acceptable way of improving recovery;

- an alternative to natural gas while maintaining reservoir pressure by pumping oil into the gas cap. The essence of this method is to replace the production of hydrocarbon gas produced in the field with cheaper nitrogen. In addition, due to intrathecal segregation, nitrogen gradually becomes a barrier between the oil and gas portions of the reservoir, resulting in, due to poor miscibility with oil, minimizes the risk of breakthroughs to bottomhole of producing wells and provides the so-called "gravitational" displacement;

- displacement of the "whole" of high-viscosity by-pass oil in the implementation of flooding. In a situation when there is a trapping of low-grade oil in structural uplifts, the drilling of additional production wells poses serious risks to the cost of the project. In this case, nitrogen is used to reduce oil viscosity and gravitational displacement when injected into a separate well;

- gas cap gas displacement. In the presence of significant reserves of gas in the gas cap and significant production of the oil from significant part of the reservoir, nitrogen can be used to further recovery of natural gas volumes by pumping additional amount of nitrogen;

- mixed displacement of oil. This method can be applied in the presence of a reservoir with low oil viscosity capable of mixing with nitrogen at formation pressure and temperature;

- maintaining reservoir pressure in gas condensate reservoirs.

A wide range of nitrogen applications is associated with the positive results of numerous laboratory studies. Experiments on contact evaporation (CVD) of hydrocarbon liquid during N_2 injection have shown that when nitrogen fills with 50% of the reservoir pore volume, evaporation of up to 16% of the liquid phase from the mixture occurs. The analysis of experiments on the pumping of nitrogen through the core, saturated with "heavy" oil, shows that the mixing of hydrocarbons with the agent does not occur, but at equivalent reservoir pressure and temperature, the nitrogen is quite inert, and its properties can be compared with the properties of the reservoir fluid, which is positive during the filtration process in the pore space.

Nitrogen injection was carried out at a cluster of fields in Wyoming, USA. The already mentioned oil and gas condensate deposit Rocky Moutains is a sandy layer with a high degree of layered heterogeneity and low permeability (2 mD). The depletion of the deposit at the time of implementation was 40%, simultaneously the dew point pressure was reached. Pumping the mixture with 35% of nitrogen and 65% of methane allowed maintaining constant condensate production for several years, but after pumping nitrogen over 0.6 of pore volume, the proportion of liquid hydrocarbons began to decline sharply. This fact coincided with an increase in the concentration of nitrogen in the production of wells up to 90% by gas phase. After that, the nitrogen injection was stopped and the pressure was maintained by dry natural gas.

5. Water-gas mixtures injection into the oil reservoir

Injection of gas into the reservoirs to maintain reservoir pressure began to be used much earlier than flooding. Prior to the application of artificial flooding, the injection of gas into the reservoirs was considered economically justified, since it allowed to increase the oil production by 5 - 10%, and in the reservoirs with steep deposits - by 15 - 25%. Then it became clear that the use of gas (without mixing with oil) is less efficient than water. Here, the main role is played by the low viscosity of the gas (10-15 times lower than the viscosity of water).

Unlike water, which in the hydrophilic layer, when it is pumped, occupies small pores, gas in the contaminated zone occupies large pores (phase that does not wet the rock). This made it possible to conclude on the feasibility of combining the positive qualities of water and gas. It was found that the combined action on the reservoir by gas and water (gaseous action) is more effective than the injection into the reservoir only one of these agents. With optimal use of this process, oil recovery can be increased by 7 - 15%.

The gaseous action on the reservoir can occur with various modifications of the injection of working agents:

1) sequential injection (water - then gas, or gas - then water);

2) simultaneous at different ratios in the mixture;

3) cyclic (alternating) injection;

4) a combination of these modifications. The process is possible under conditions of equilibrium of gas and when mixed with oil.

Injection gas together with water led to the development of a gas-cycle method of action as a more efficient method of enhancing oil recovery than used separately on a large scale flooding and, as an experiment, pumping gas (under immiscibility conditions). In this case, the displacement factor increases due to the presence of free gas in the amount of marginal gas saturation (10-15%), in which the gas is motionless. It is most advisable not at the same time, but intermittently to pump gas and water, providing the total content of one of the agents by 25-75% in the gas mixture. The duration of the injection cycles of each agent is 10...30 days. Joint injection is difficult to carry out for technical reasons (formation of hydrates, gas ingress into water pipelines, etc.).

Gas methods were implemented at the Bitkivsky field (injection of dry gas in the absence of phase mixing, gas-water action at pressures of 18-20 MPa).

Control questions

1. What is the essence of using dry hydrocarbon gas to increase oil recovery?

2. What are the main criteria for the efficiency of the process of dry hydrocarbon gas injection to enhance oil recovery?

3. What is the technological scheme of pumping and treatment of dry petroleum gas?

4. What is the technology of dry hydrocarbon gas pumping and treatment in order to enhance oil recovery?

5. What are the features of using high pressure gas to increase oil recovery?

6. What are the features of using enriched and liquefied gas to enhance oil recovery?

7. What are the features of using non-hydrocarbon gases to enhance oil recovery?

8. What technologies of carbon dioxide injection are used in practice?

9. What are the advantages and disadvantages of using carbon dioxide to enhance oil recovery?

10. How is nitrogen used to enhance oil recovery in practice?

11. What is the supply of gas-gas mixtures to enhance oil recovery?

12. What are the modifications of the injection of working agents into the reservoir under gas-water action to increase oil recovery?