Some Possibilities of Increasing the Completeness of Oil and Gas Recovery

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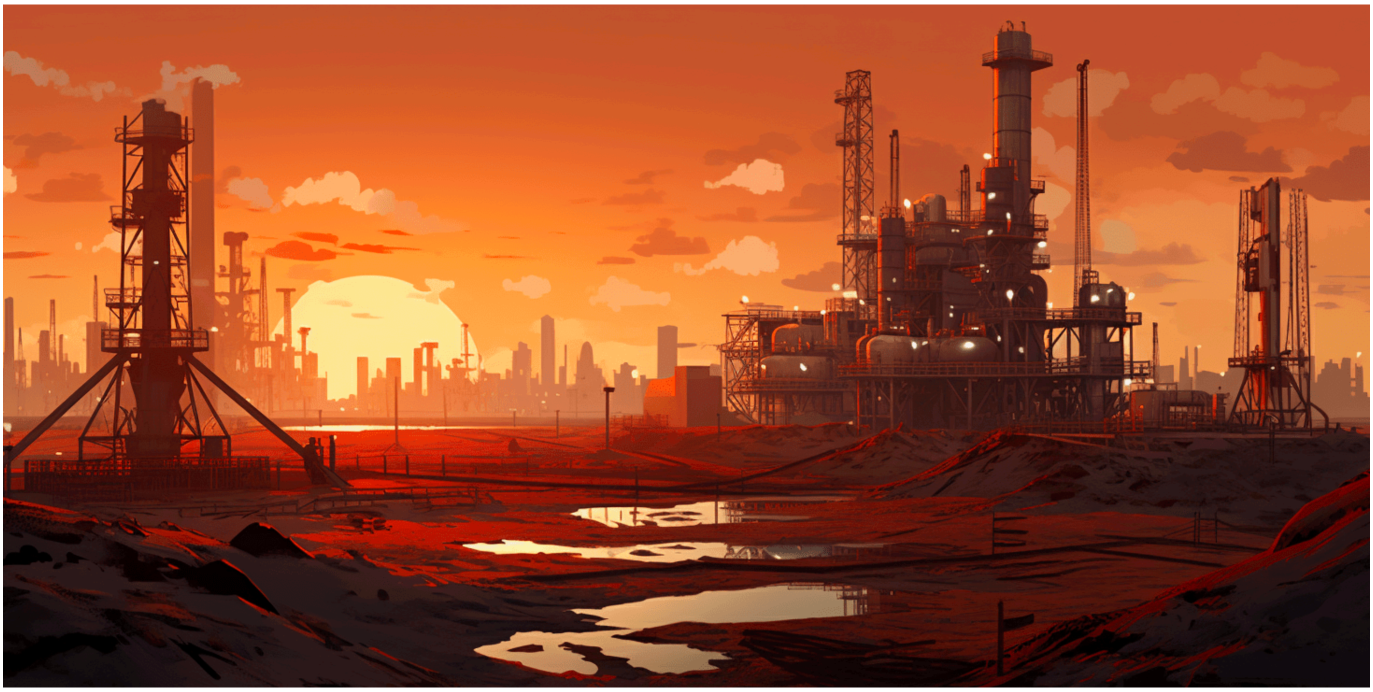

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Some **Possibilities** of **Increasing** the **Completeness** of **Oil** and **Gas Recovery**

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Abstract.

The purpose of this work is to focus the attention of specialists in the field of development and exploration of oil and gas fields on the possibilities of increasing the completeness of oil and gas recovery by taking into account natural phenomena that occur in pools, using existing methods development. Failure to take into account these natural phenomena causes low completeness of oil and gas recovery, as well as unjustified costs in the development of pools.

As a result of 60 years of research by a large group of specialists in various fields of knowledge, the presence of a number of natural phenomena in oil and gas pools was established, and taking into account them, the completeness of gas, condensate and oil recovery from a number of pools was increased. The following main natural phenomena have been identified:

1. Multi-scale block structure of all pools and the absence of hydrodynamic connection between different parts of each pool within the framework of Darcy's law.

2. Changes in the filtration properties of the pool during development.

3. Influence of fractionation of hydrocarbons in pools on the properties of produced and residual oil during water flooding in sediments with different reservoir properties.

The following proposals are substantiated:

• Additions to the complex of exploration works;

• Some ways to increase the completeness of oil and gas recovery;

• The results of the industrial use of a comprehensive study of conventional and unconventional oil and gas pools.

Keywords: Completeness of oil and gas recovery; Multi-scale block structure of pools; Fractionation of oil and condensate; Initial pressure gradient.

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Introduction.

Most of the conventional pools are being developed on the assumption that the chosen development system will provide the maximum available oil and gas recovery at current prices. For a long time, in most cases, the oil recovery factor **ORF** was taken equal to **~0.3**, now on average **ORF~0.4.** Probably the most successful is the development of the Prudhoe Bay field. According to experts, by now, **ORF~0.6**; it is expected to reach **ORF~0.64** [59]. These **ORF**s also include oil production from parts of the field that were not previously developed and, therefore, were not taken into account in the previous stages of field development. These **ORF** estimates differ significantly from previous design indicators [35, 68], which were made mainly in the study of the efficiency of the field gravity drainage mechanism by means of laboratory experiments. They concluded: "The 'most likely' displacement efficiency, through the stochastic approach, was 0.**68** after three years and 0.**76** after 30 years of gravity drainage." This optimistic forecast was made at a time when oil production peaked from this pool. Despite the use of advanced reservoir development systems, insufficient consideration of its internal structure led to the selective recovery of oil from the part of productive deposits, which was noted in 1995. Core data from a sidetrack well 250 ft. from an old injection well revealed highly permeable rock intervals with $S_{or}\approx 0.05$ residual oil. In other intervals, the S_{or} values were higher, and in some intervals, oil displacement did not occur [47]. The data show that effective **EOR** methods that have only been tested on core samples may not be as effective in the field conditions if their application is carried out without taking into account the real larger-scale filtration heterogeneity of reservoirs [18]. The Prudhoe Bay field is located in a tectonically active zone, so a priori, it can be argued that there are numerous sub-vertical channels - **SVC**s and low-permeable barriers - **LPB**s in the pool. Under these conditions, the use of a traditional filtration model, which assumes the presence of a hydrodynamically connected reservoir within the framework of Darcy's law, leads to a decrease in the efficiency of the development systems used. The zone in which the gas cap has been identified is probably one or more tectonic blocks; they are separated by **LPB**s. The presence of other blocks within the pool is very likely. The boundaries between the blocks manifested during the development of the pool. During the injection of various fluids for enhanced oil recovery, unpredictable trajectories of their movement occurred, mainly through **SVC**s. Numerous subsequent adjustments to the development design using various methods to improve oil recovery: increasing well spacing (original distance of 320 acres per well was quickly reduced to 160 acres per well, and then reduced to 80 acres per well), drilling deviated wells, etc. d. allowed to increase the achieved current value of the **ORF**, but did not reach the calculated value of the **ORF** [35, 68]. The forecast estimates of the **ORF** turned out to be clearly overestimated, since the actual development of the pool continues to be carried out within the framework of the filtration model, which did not correspond to the actual internal structure of the pool and the processes that took place in it during oil recovery. Due to the lack of information, it is difficult to comment on the effectiveness of the use of **WAG** after water flooding. Taking into account the natural phenomena identified by us in pools would probably allow us to achieve greater completeness of HC recovery.

Part 1. Some natural phenomena that determine the completeness of oil and gas recovery and the possibility of taking them into account in the exploration and development of hydrocarbon pools.

The economic and organizational reasons for the current situation should be dealt with by appropriate specialists; in this work, it is proposed to consider the fundamental natural limitations in the systems of exploration and development of oil and gas pools. For many years, exploration, development and evaluation of hydrocarbon - **HC** reserves have been based on the assumption that the pool is a reservoir for which the following postulates apply [1, 44]:

1. There is a hydrodynamic connection within the entire reservoir; the fluid flow in it can be described in terms of Darcy's law.

2. Productive deposits in conventional oil and gas pools are hydrophilic.

3. During the reservoir development, its filtration parameters are practically unchanged.

4. Hydrodynamic connection is absent between reservoirs in different tectonic blocks.

5. Properties of reservoir fluids are the same in different parts of the pool. The properties of residual oil when using water flooding are identical to the properties of the produced oil.

Filtration models of reservoirs, which are based on these postulates, hereinafter **FM1**, are the basis for designing systems for the development of oil and gas pools, as well as for applying **EOR** methods. This model underlies the requirements for the results of exploration work on the identified accumulations of oil and gas. However, these postulates do not correspond to the experience of developing almost all oil and gas pools. After establishing the absence of hydrodynamic connectivity between different parts of the pool, first of all, the well spacing pattern of development wells is densified. These wells are mostly drilled blind; local development of the pool is practically starting. When using the newest methods, **EOR** also focuses on the traditional reservoir **FM1** model, which reduces their efficiency and causes unjustified high costs. This is clearly seen in the relatively successful application of Polymer Flooding in China's largest oil field, Daqing [28].

The limited applicability of these postulates is most obvious in the development of gas pools and unconventional oil and gas pools, which contain huge resources and are actively barbarously developed in many countries. Only in the deposits of the Bazhenov formation within the West Siberian oil and gas province, according to the latest estimates, oil resources exceed 100 billion tons. At the same time, more than 60 years of pilot development of a number of fields, including the participation of specialists from the largest oil companies in the world, did not allow choosing a development system that is economically suitable and can provide rational oil recovery [30, 42]. It is usually assumed that barriers between different parts of the pool arose during the period of sedimentation; many use the term compartmentalization [38], which, according to the dictionary of the firm Schlumberger, is: "The geological segmentation of once continuous reservoirs into isolated compartments. Reservoirs that have become compartmentalized require different approaches to interpretation and production than continuous reservoirs. The degree of compartmentalization may vary as a consequence of production".

The low completeness of oil and gas recovery is due to not taking into account the complex influence of the following natural factors:

• Features the internal structure of pools and fluid flow in them;

• Limited accounting for the influence of interactions of hydrocarbons with the pore surface of various production deposits.

1.1. The internal structure of pools and features of fluid flow in them.

Conventional and unconventional **HC** pools contain thin (in most cases no more than a few meters), laterally extended (up to 10 km and more) sub-vertical channels – **SVC**s. **SVC**s appear during neo-tectonic movements before and after **HC** migration into reservoirs. Part of **SVC**s contains country unconsolidated low-permeable rocks. A significant part of **SVC**s is oriented across the bedding. In extension zones, **SVC**s are practically fractures with anomalously high permeability. Beginnings of **SVC**s cause periodic overflows of gas and oil into **HC** traps. On the territory of the West Siberian oil and gas basin, some fields have been identified that contain up to 40 gas, gas-condensate and oil pools, as well as the presence of residual oil in gas pools, for example, in the crest of the Cenomanian gas pool at the Urengoyskoye field [18, 31, 55, 77] (see Appendix 1).

SVCs can partially be identified based on the results of complex studies of aero-space methods, 3D seismic surveys and hydrodynamic studies, as well as field observations for the development of the pool. They are not recorded according only to 2D seismic data due to their physical limitations (see Appendixes 1 and 2). The length of channels, in most cases, is established by the injection of various indicators. The results of the injection of indicator solutions in the Bazhenov formation at the Em-Yogovskoye oil field showed that the tracer left after 12 km was recorded in a nearby area. In one of the highly productive wells in the Bazhenov formation, after the production in the depletion drive and the cessation of production, a tracer was injected, which identified the presence of a filtration channel between highly productive wells with a length of more than 4 km and a permeability of 37–50 D. The volume of the channel is ~28 m^3. When developing **HC** pools while maintaining formation pressure by injecting various fluids for a complete **HC** recovery, the presence of **SVCs** in the pool causes uneven well production in the initial period of development, unpredictable trajectories of the injected fluids, breakthroughs of injected fluids into producing wells; selective displacement of oil from only part of the pool. **A**t the Mamontovskoye field, the development of light oil pools is carried out by water flooding, according to the results of the injection of indicators into Cretaceous terrigenous deposits (average values of porosity m~0.2, permeability K~100 md), it was found that 42% of the injected water enters through anomalous filtration channels. The permeability of such channels in the reservoirs of the Samotlor field (average values of m ≥0.2, K ≥100 md, oil viscosity in reservoir conditions <4 mm^2/s) is 30–50 D. The presence of such highly permeable channels was recorded in all oil fields where various indicators were injected during oil displacement by water [18, 30].

SVCs that are oriented predominantly across the bedding, with a decrease in formation pressure in developed pools, determine the water encroachment of producing wells with bottom water, which leads to a significant decrease in the completeness of gas and oil recovery (see Appendix 1). In pools that are composed of carbonate deposits, the influence of **SVC**s is especially strong. This manifested itself, in particular, in the development of the giant Orenburg oil-gas-condensate field, where a large part of producing wells was practically water encroachment as formation pressure decreased during gas recovery. When drilling wells in gas and oil pools with abnormally high formation pressures, for example, in Western Uzbekistan, a large number of emergency fountains occurred until, according to seismic survey data, vertical fracture zones could not be localized [18].

In the compression zones, **SVC**s turn into low-permeable barriers are designated as **LPB1**s. Compression zones, in many cases, are due to the influence of low-amplitude horizontal shifts of the basement [31, 33]. Fluid flow through **LPB1s** occurs only at pressure gradients above some initial value – **IPG** [18]. Studies of core samples from such **LPB1**s, predominantly fixed in outcrops, showed that the gas permeability of dry samples is in the range of 10 ND to 1 md [27, 74]. These are very approximate estimates of barrier permeability, since these rocks could be subject to repeated compaction and erosion, but they are close to the results of permeability determinations on dried core samples from formations in which **IPG** was recorded in natural conditions when they contained gas and irreducible water.

The low permeable rocks that are traced between the barriers oriented across the bedding are lithological barriers and are named **LPB2**s. These barriers differ from the more common **LPB1**s barriers in their orientation within the pool and in the fact that they are composed of compacted, low-permeable rocks. These differences determine the features of the fluid flow through **LPB2**s during the development of pools (see below).

The **IPG** values for fluid flow through low permeable porous media in **LPB1s** and permeability of **SVC**s are determined by the following factors:

- Petro-physical properties of composing rocks;
- The physicochemical properties of the fluids that are contained in them and move through them;
- The changes in the stress state.

The influence of these factors on the filtration properties of **LPB1**s and **SVC**s is shown below.

For the first time, the presence of an initial pressure gradient during gas flow through low-permeable porous media with irreducible water was established on artificial samples [4]. The presence of barriers in pools, through which the gas flow occurs only at pressure gradients above a certain initial value, was established from the results of observations of the dynamics of formation pressure at different stages of the development of some pools of the Gazli field [10].

1.1.1. Residual formation pressure difference in a non-producing gas pool in horizon IX of Gazli field after uncontrolled gas blowout.

The pool is situated at an anticline on an area of about 14x40 km with an amplitude of ~250 m (see Fig. 1). The pool is composed of highly porous and highly permeable Upper Cretaceous terrigenous deposits, the permeability of individual core samples >1 D. Initial formation pressure ~7.3 MPa. The development of the pool was started in 1963 [10, 13].

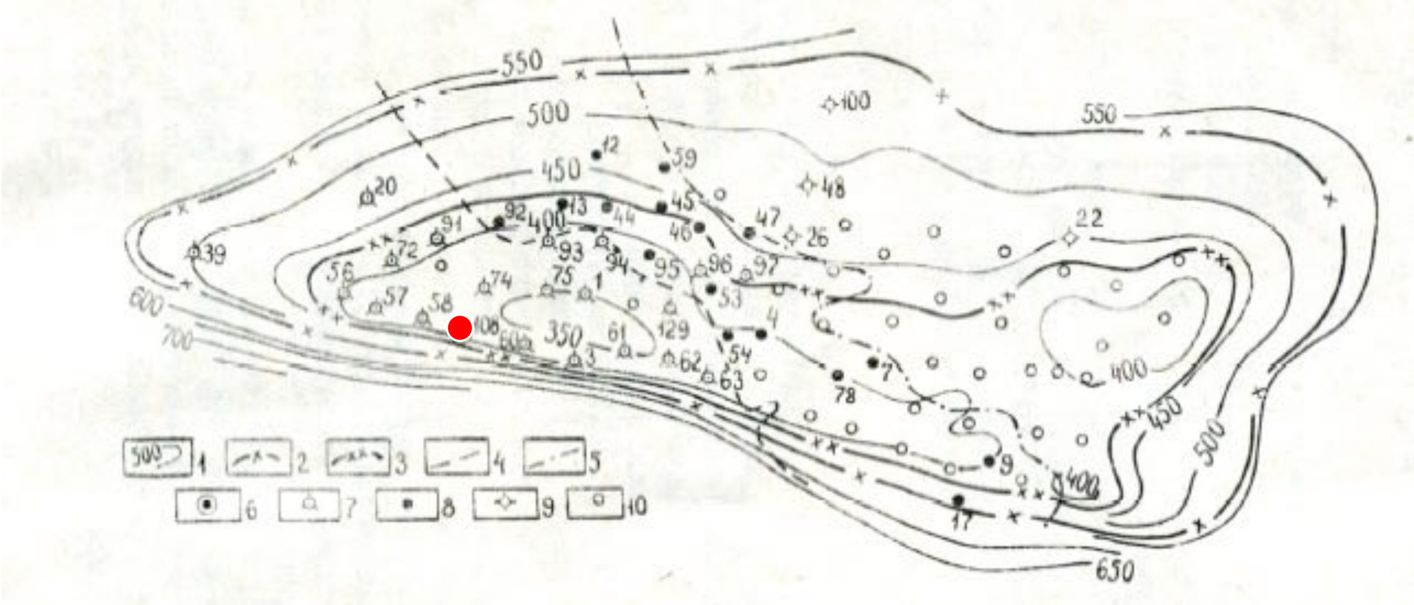


Figure 1: Structural map on the roof of the horizon IX of the Gazli field:
1-isohypses along the roof of the horizon IX; 2, 3- external and internal contours of gas pool, respectively; 4, 5 - an approximate position of **LPB1**s between the blocks, respectively, I – II and II - III; 6- the position uncontrolled gas blowout in well No.108; 7-9 - observation wells located in the blocks I, II and III, respectively; 10 - producing wells drilled after the uncontrolled gas blowout was killed.

The reservoir development project was drawn up as part of **FM1** and provided for the drilling of more than 80% of producing wells with a density of 1 well per 2 km^2 within the so-called dry field - a zone of lack of bottom water within the horizon. Approximately 70% of the initial gas reserves are confined to this zone. During the drilling of producing well No. 108, an uncontrolled gas blowout occurred that lasted 21 months, and gas losses formed ~2% of initial reserves. Within this period and after stopping uncontrolled gas blowout during the following two years before the beginning of industrial gas production, the measurements of formation pressure were performed repeatedly in **39** wells situated at distances from 1.3 to 18.4 km from well No. 108. In the period, the formation pressure decreased in all the observation wells; an exception is in the well No. **100** (see Fig 1).

In according with classical theory for the disturbance, the formation pressure distribution may be described by the equation of linear gas flow from a well:

$$P_{f0}^2 - P_{fi}^2 = Q^*\cdot\mu\cdot P_a\cdot(2\pi Kh)^{-1}\cdot\ln \chi\cdot t\cdot R_f^{-2} \qquad (1);$$

Where: $2\chi\cdot t\cdot(r_o)^{-1} >> R_f > 3\,(\chi\cdot t)^{0.5}$; $\chi = K\cdot P_{f0}\,(\mu\cdot m)^{-1}$; P_{f0} – initial formation pressure, P_{fi} – current formation pressure in observation well, P_a – atmospheric pressure, R_f - the distance from observation well to the damaged well; r_0 - well radius; Q* – gas losses; μ - gas viscosity; K, m, h – pool permeability, porosity and thickness, respectively; t – time elapsed from the beginning of the uncontrolled gas flowing.

In the period, the formation pressure distribution in observation wells was described by equation 1 with an error of about 10% (see Fig. 2).

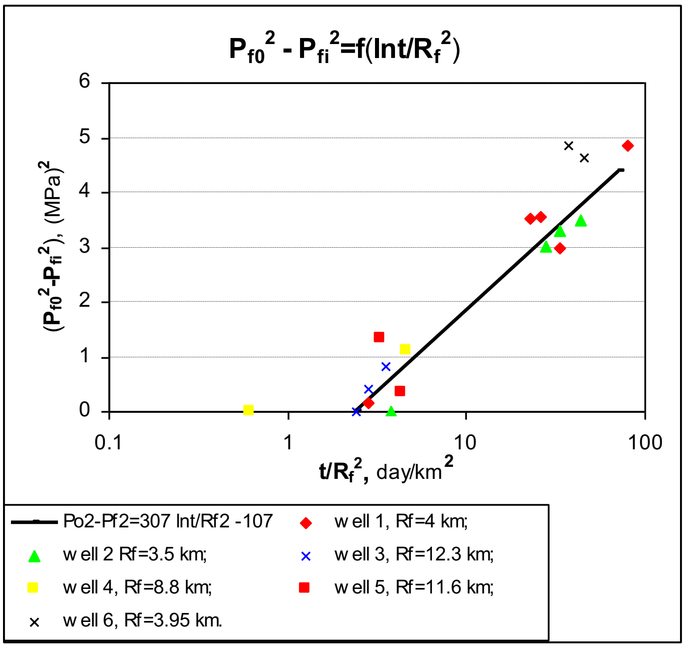


Figure 2: Dependence $|P_{f0}^2 - P_{fi}^2| = f|\ln(t/R_f^2)|$ on observation wells during the flowering period of well No 108.

The corresponding formation pressure data may be described by a regression equation of the form:

$$p_{f0}^2 - p_{fi}^2 = b_0 + b_1\left(\ln\frac{t}{R_f^2}\right), \qquad (2),$$

Where b_0 and b_1 are regression coefficients.

The dispersion of measured data relative to results obtained by using the equation (**I**.2) is only 1.5 times greater than the dispersion of a single P_{fi} measurement. This distinction is statistically insignificant. In the framework of the conventional reservoir model, in the horizon IX, the value is Kh=7.6 Dxm, and at the average thickness of the main gas-saturated part of the pool 60÷70 m, the permeability **K** is ~0.1D. This value is close to the permeability estimates made by using the hydrodynamic investigations and by laboratory measurements.

Within the traditional filtration model, which postulates reservoir connectivity within the framework of Darcy's law [44], after stopping uncontrolled gas blowout followed to wait for formation pressure recovery in the pool parts near the approach emergency well and decrease of differences of current formation pressure in difference pool parts. If the uncontrolled gas flowing was in the homogeneous reservoir and Darcy's law was valid, theoretically (in linear approximation), the unsteady formation pressure distribution around the blowout gas well at the time $t>T$ (T- total time of gas flow from the emergency well) must be described by the equation:

$$P_{f0}^2 - P_{fi}^2 = Q^* \cdot \mu \cdot P_a \cdot (2\pi K h)^{-1} \cdot \ln t \cdot (t-T)^{-1} \qquad (3).$$

The comparison of measured and calculated formation pressure values shows that equation (3) is inadequate to describe the formation pressure distribution in the pool after stopping uncontrolled gas flow from the damaged well, i.e., at the stage of formation pressure build-up (Fig.3).

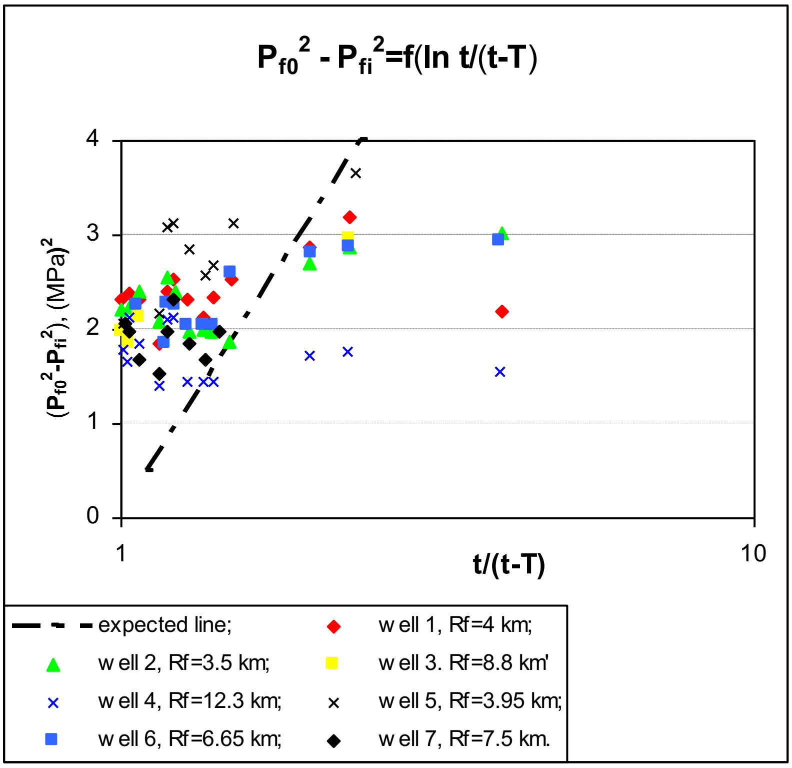


Figure 3: Dependence $|P_{f0}^2 - P_{fi}^2| = f|\ln(t/(t-T))|$ on observation wells after killing of well No 108.

After stopping the uncontrolled gas blowout, P_{fi} values changed **only** in observation wells located closer than ~10 km from the emergency well. The formation pressure in this zone reached equilibrium after six months after the interruption of the uncontrolled gas blowout. In the wells located farther from the emergency well, the P_{fi} values remained unchanged from the moment of the uncontrolled blowout interruption right up to the beginning of the industrial gas production from the pool. As a result, in the undeveloped pool, at the period of more than a year, distinct formation pressure differences up to ~**0.16** MPa existed between zones of the pool, which exhibited good hydrodynamic connectivity in the period of uncontrolled gas flow. The results of formation pressure measurements after stopping the blowout indicate the presence of barriers through which gas flow between different parts of the pool occurs only at pressure gradients greater than some values of the initial pressure gradient both from the emergency well No. 108 and in the opposite direction after the blowout is killed.

The difference of P_{fi} values inside of the undeveloped pool after interruption of an uncontrolled gas flow can't be explained within the framework of the traditional filtration model; this model is not adequate for this pool. After the interruption of uncontrolled gas flow and formation pressure recovery inside the pool within the limits of the traditional model, the equilibrium formation pressure should be established, which is the value of $|P_{f0} - \Delta P^*|$, where the value ΔP^* is defined by gas losses during the emergency gas flow. Instead, the inside of the pool preserved differences of P_{fi}

values between some parts of the pool for more than a year, and gas cross-flow inside the pool didn't take place. Inconsistencies in the direct and reverse redistribution of formation pressure in the pool can be explained in the framework of the Block Filtration Model - **BFM**, which consists of some blocks - **MSB**s. These blocks are divided by **LPB1**s (see Figure 1). The difference in formation pressure in an undeveloped pool is due to the fact that these pressure gradients are less than those necessary for gas flow through **LPB1**s that divide the pool into **MSB**s. Within the limits of the **BFM** pressure stabilization after stopping the gas cross-flow inside the pool, which has a block structure, takes less time than the time inside a quasi-homogeneous reservoir. The retained formation pressure measured after stopping the uncontrolled gas blowout was:

$$P_{fi} \approx P_{f0} - \Delta P^* - G_g h \qquad (4);$$

Where: G_g –the **IPG** value for gas flow through **LPB1**s between the block in which the fountain well is located and the blocks with observation well; h – the thickness of the **LPB1s** in the areas of gas flow.

The measurements of P_{fi} values allowed us to distinguish a minimum of 4 **MSB**s and to estimate the values of **IPG** (see Fig. 1). In each such block, equal P_{fi} values were established. (Only in well No. 100 remained the initial formation pressure; this well is located in the fourth block, the boundaries of which have not been determined due to the lack of appropriate observations of changes in formation pressure within the entire area of the pool). The three blocks within the dry field are separated by laterals with different **LPB1**s. At the beginning of industrial production, average values P_{fi} differed inside blocks I, II, and III and were equal to 7.04, 7.09 and 7.13 MPa, respectively; the standard deviation value is ≤±0.02 MPa, which corresponds to the measurement error of P_{fi} values. The mean values of P_{fi} in different blocks are statistically significantly different. The P_{fi} values were identical within each block independently from the distance from the observation wells to the emergency well. This conclusion follows from more than 60 formation pressure measurements in the **MSB II**, where observation wells are situated at a distance of 3.2÷16.3 km from the emergency well. When determining the average value of P_{fi} in **MSB III**, the value of $P_{fi}=P_{f0}$ in well No. **100** was not taken into account. Thus, within the gas pool, prior to the beginning of its industrial development, there were at least 4 **MSB**s, which were separated by **LPB1**s. Through these **LPB1**s, the gas flow occurs only at pressure gradients that exceed the magnitude of the **IPG;** these values of **IPG** were different for the flow of gas between the various **MSB**s. The positions of the allocated **MSB**s and the position of the **LPB1**s between **MSB**s **I÷III** and well No. **100** are determined by the deformations of the sedimentary deposits as a result of tectonic and neo-tectonic activity in the area of the structure. The approximate boundaries of the **MSB**s **I, II, and III** are correlated with the results of the study of the new tectonics of the structure. The probable position of the identified **LPB1**s is confined to the trough between the western and north-eastern domes, which was most clearly recorded within the underlying gas and oil and gas pools [10].

The presence of barriers in the gas pool of the 1X horizon and the fact that at the initial formation pressure - P_{f0} in the pool, the **IPG** values between the identified blocks were small and were manifested during the development of the pool. This follows from the estimates of changes in the drained volume of the pool – V_{dri} and changes in the values of **IPG** during the gas flow through the barriers into the production zone at different stages of the pool development. The **IPG** values at the P_{f0} in the pool were less than 0.1 MPa/m; as reservoir pressure decreases in the pool, two stages of

V_{dri} decrease and increase in **IPG** values are recorded. The decrease of V_{dri} value by ~10% was noted at **GRF**~0.3 with a decrease in P_{f0} value by ~2 MPa. When the formation pressure decreased by ~4.5 MPa, the distinct decrease of V_{dri} by ~30% was noted at **GRF**~0.75 (Appendix 1). The formation pressure differences in parts of the pool between the identified barriers and the barriers that appeared when the formation pressure decreased in the pool gradually increased from values less than 0.1 MPa to 1.5 MPa, and, accordingly, the **IPG** values reached ~2 MPa/m.

The filtration model of the pool varied depending on the well spacing of the producing wells used and the deformation of low permeable rocks in the barriers. The initial gas withdrawal, including the emergency flowing of well No. 108, was controlled by four blocks (see Fig. 1.). With a decrease in formation pressure and the transition to positive choke operation of wells for a short time, almost the entire zone within the dry field turned into one large block, and the current formation pressures in the wells located there almost leveled off. The subsequent decrease in formation pressure caused significant deformation of low-permeable rocks in the barriers and in **SVC**s, which led to the division of the developed pool into smaller blocks and an increase in the volume of stagnant zones. This led to a decrease in the gas recovery factor from the pool, as drilling of wells in stagnant zones was not carried out.

The influence of low-permeable barriers on the dynamics of the development of the pool was clearly manifested in the activity of intrusion of marginal waters into it. By the beginning of 1970, with the current gas recovery factor of ~0.27, ~120 million m^3 of marginal water had intruded into the pool; active water intrusion began almost immediately after the decrease in formation pressure in the pool. During this period, as well as in the next ten years of development of the pool (up to the recovery of ~75% of gas reserves), not a single producing well within the dry zone had not water cutting of well production, i.e., marginal water did not penetrate the pool through the barriers. Subsequently, in one well within the dry field, according to the repeated neutron logging data, a slight decrease in the gas content in one productive bed was recorded; at the same time, there was no increase in the content of condensation water in the production of this well. Probably, the decrease in the gas content in this bed is due to the presence of a non-localized sub-vertical channel, through which bottom water penetrated from the underlying X horizon; the gas pool in this horizon was also under development [10, 18].

Changes in the filtration resistance of the pool also affected the differences in changes in formation pressure in the production zones and in the observation wells, in which the formation pressure was higher than in the gas production zones and systematically higher in the observation well No. 100 compared to the data in the observation well No. 39 (see Fig. 1 and 4).

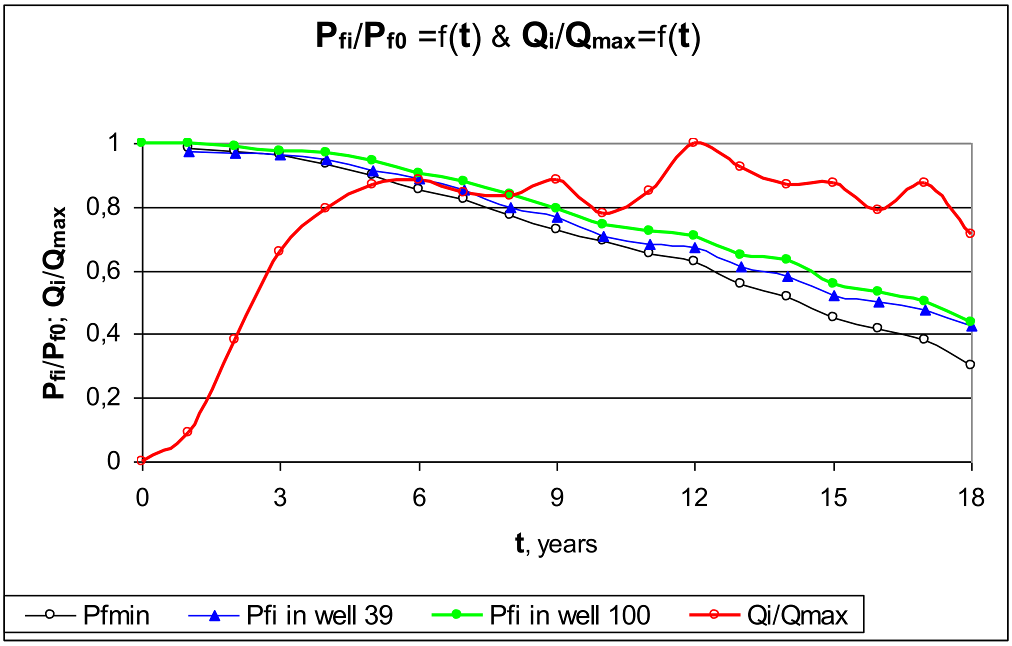


Figure 4: Dynamics of changes in formation pressure and gas recovery rate during the development of a gas pool in the 1X horizon of the Gazli field. Qi -is the total volume of gas production from the pool for the current year; Q_{max} is the maximum volume of gas production from the pool during the constant production period; t - is the year of pool development; P_{fi}/P_{f0} - changes in formation pressure in the gas production zone (-◦-◦-) and in observation wells No. 39 (-Δ- Δ-) and No. 100 ----.

The data presented allow us to draw the following conclusions:

1. The gas pool of the 1X horizon of the Gazli field is a junction of at least four blocks. These blocks are separated from each other by low-permeable barriers through which the gas flows only at pressure gradients greater than a certain value of the initial pressure gradient **-IPG**. At the initial formation pressure in the pool, these barriers have practically no effect on the value of the drained volume of the pool - V_{dri} with the accepted well spacing of producing wells. At this stage, the number of producing wells was excessive, in particular in block **II**, since all wells were highly productive and production was at a depression of no more than 0.2 MPa.

2. The **IPG** values at which gas flows through the barriers increase with a decrease in formation pressure in the pool, which causes a decrease in the V_{dri} value and the formation of stagnant zones from which gas does not enter the production zone. To increase the completeness of gas recovery, additional producing wells are needed in stagnant zones, in which industrially significant gas reserves are stored.

3. Experience in the development of this pool shows that at the producing test of the pool with a small volume of produced gas and a system of location of producing and observation wells planned within the block filtration model, it is possible to localize the main barriers in the pool before the start of commercial gas production.

1.1.2. Field tests of gas flow to wells from low-permeable rocks.

If the gas flow in low-permeable sediments occurs only at pressure gradients that are larger than some **IPG** value, then an incomplete pressure recovery should be expected when performing non-stationary tests of productive layers isolated by impermeable rocks of the gas pools. Gas flow to a well in low-permeable layers stops, when the pressure gradient in the pool around the well is less than **the IPG** value. This occurs, when the pressure difference ΔP_i between the formation pressure before tests P_{fi} and the formation pressure near the well bore P_{bi} is less than the **IPG** value (***Gg***), multiplied by the distance - L_i from the wellbore wall to the part of the pool, where P_{fi} preserves:

$$\frac{\Delta P_i}{L_i} \leq Gg \qquad (5).$$

In well No. 504 of the Gazli field, an undeveloped gas pool of the horizon VIII-B, consisting of terrigenous low-permeable rocks with a thickness of ~21m, was exposed to gas flow [7, 10]. The layer was tested at stationary flow, and then the pressure build-up testing was performed. The indicator diagrams describing the $\left| \frac{p_{fi}^2 - p_{bi}^2}{q_i} \right|$ value as a function of q_i (where q_i is the gas flow rate) were anomalous (see Figure 5).

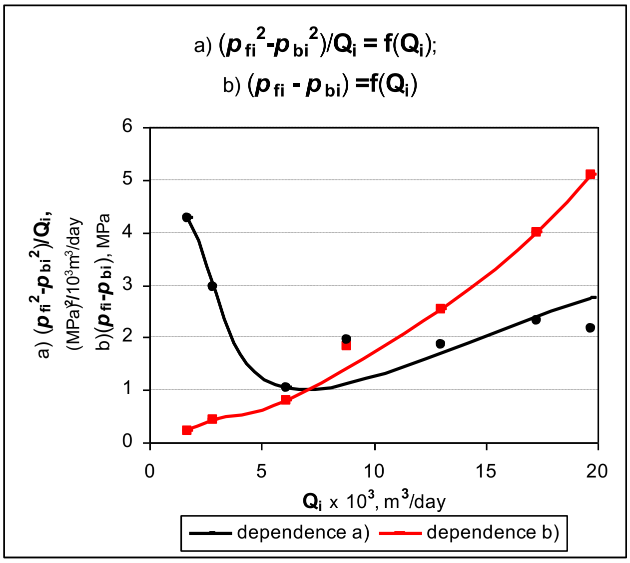


Figure 5: Indicator diagrams on low-permeable deposits, well No 504, the Gazli field.

The formation pressure measurements, performed six months after the testing, showed that bottom-hole pressure was **0.2** MPa lower than initial gas formation pressure, and this difference remained unchanged at least for the next year. These results show the nonlinearity of gas flow through the low-permeable rocks in this layer and a possibility of **IPG** existence.

In producing a pool, if parts of the pool are connected only by such low-permeable rocks or **LPB**s, the stagnant zones, where there is no gas flow, are formed. The formation of stagnant zones inside development gas pools is confirmed by investigation data of numerous gas pools [18]. The presence of **IPG** during gas flow in low-permeable sediments is clearly recorded during shale gas and tight gas production. This necessitates an increase in the drainage zones of producing wells by drilling horizontal shafts and carrying out numerous hydraulic fractures. With such completion of wells, their productivity rapidly decreases, and the current formation pressure in the drainage zone sharply decreases. Probably, gas production from such wells is greatest if the drainage zone is connected with a **SVC**, which is not predicted when choosing the drilling sites for such wells. Estimation of gas reserves in such pools is carried out locally in the drainage zone of each well [18, 22].

1.1.3. Features of gas flow through lithological barriers.

The main productive sediments of the gas pool in horizon **X** Gazli field are composed of highly porous, highly permeable sandstones. In this pool, six main units of the productive deposits, divided by argillaceous sediments, are located one above the other. In five upper units, from X(I) to X(V), the values of initial formation pressure - P_{f0} were almost identical and equal to ~8.2 MPa. The position of the initial gas-water contact **GWC₀** along the lower unit X(V) in the central part of the pool was recorded at an absolute mark of -630 m. Within unit X(VI), the main local gas pool is confined to **GWC₀**=-640 m and P_{f0}~9.2 MPa. The thickness of argillaceous sediments separating units X(V) and X(VI) is ~6 m. The gas production was only from the five upper units; the gas flow from unit X(VI) occurred only through the low-permeable layers to unit X(V). The current formation pressure P_{fi} measurements in units X(V) and X(VI) were conducted in adjacent wells, in one of which the units X(I)÷X(V) are perforated, and in other, only the unit X(VI) is perforated, showed the following (see Fig**. 6**).

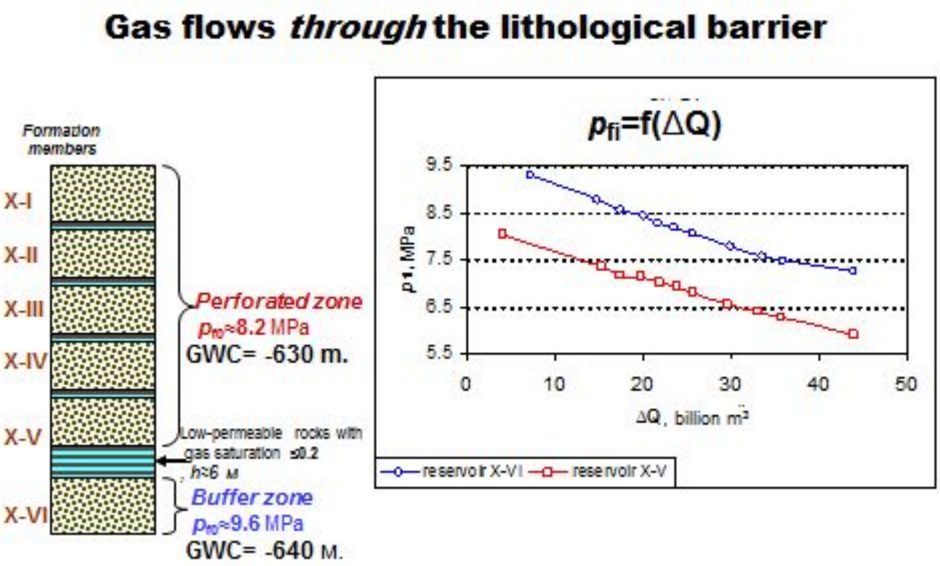


Figure 6: Dynamics of gas flows through the lithological barrier - **LPB2** in the gas pool of horizon X Gazli field.

The formation pressure was reduced in all six units, but along the gas production, the difference in the current formation pressure values in unit X(VI) and in units X(I)÷X(V) remained the same as before the pool development. The data presented characterize the period during which the rate of gas production from units X(I)÷X(V) changed by about fivefold. The gas cross-flow from unit X(VI) to unit X(I)÷X(V) during this period constituted a total of some billion m^3. The presented data show that gas cross-flow between the units takes place only if the pressure gradient exceeds some fixed value **IPG**. This value is slightly larger than the initial difference in formation pressures in these units, i.e., the pressure gradient exceeds the **IPG** value, and gas flows through rocks separating the units. In the case of flow between the units, the average value of **IPG** comprises ~0.23 MPa/m, which is close to the data obtained in laboratory experiments on field cores and artificial specimens of porous media (see below).

1.1.4. Block filtration model of gas and oil pools.

Taking into account the presence of two types of barriers - **LPB**s in pools, the pool filtration model can be considered as such Block Filtration Model - **BFM** (see Fig. 7). In each such neo-tectonic block, the presence of **SVC**s is very likely, some of which are fractures of various opening.

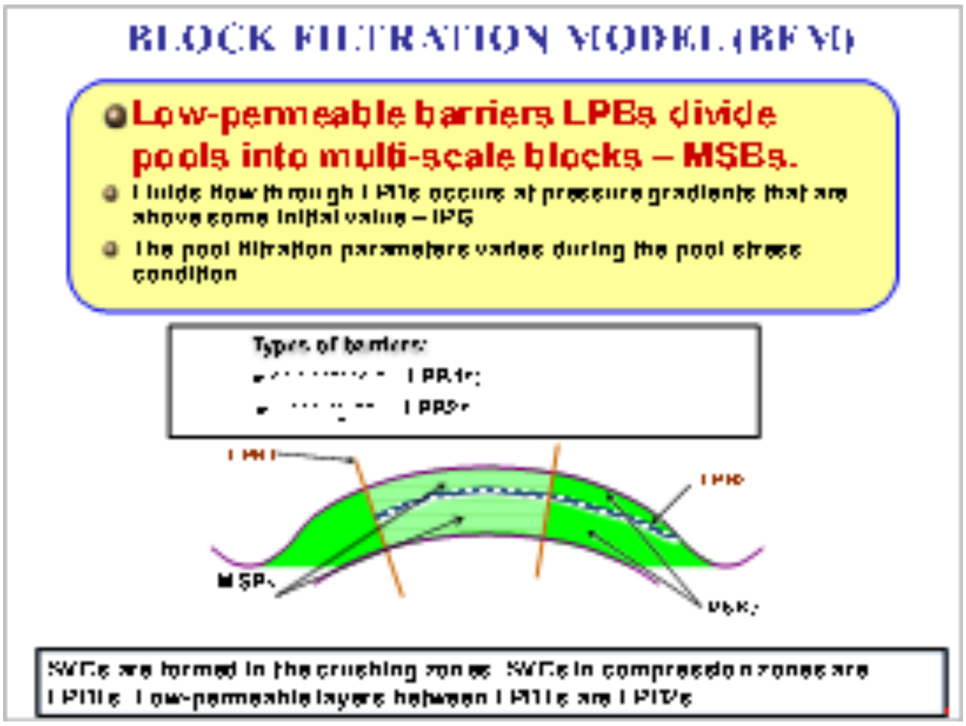


Figure 7: Schematic of a Multi-scale block filtration model of hydrocarbon pools.

HC pools are divided by **LPB**s into neo-tectonic and lithological Multi-scale blocks - **MSB**s. **LPB**s determine lateral and vertical fluid flow during pool development and pool resistance to fluid flow. This is one of the main reasons for the reservoir compartmentalization. **HC** pools are not hydrodynamically interconnected, and Darcy's law is not valid for the description of fluid flow between all parts of the pool, since fluid flow through **LPB**s takes place only at pressure gradients above value **IPG**.

Professor V. Ryzhik substantiated the mathematical model of the developed gas pool, in which the reservoir is represented by a set of **MSB**s, which are separated by low-permeable barriers. This model takes into account changes in the **IPG** values during the gas flow through these barriers with a decrease in formation pressure in the pool [18]. This model allows the estimation of drained gas reserves and residual recoverable reserves under the development system used (see Appendix 1).

Since the internal structure of **HC** pools is determined by the presence of **SVC**s and **LPB**s and their filtration properties at the beginning of the pool development and their changes in the development process, it is expedient to localize the probable position of the zones of presence of

LPBs and **SVC**s using remote methods in the process exploration work at the identified field and clarify their position and properties before and during the development of each pool. Low-permeable barriers of the **LPB1**s type occur inside sub-vertical channels within zones affected by neo-tectonic movements after compaction of sub-vertical channels, which occurs mainly after horizontal basement movements. These zones can be partially identified using remote methods. The experience of using a complex of remote methods, which includes the results of aerial surveys, satellite surveys and seismic surveys, as well as using 3D seismic surveys in the study of sections of oil and gas fields, is given in [31, 55, 61, 62, 71, 72, 77]. The need to use aero-space observations is due to the fact that these methods allow localizing and the stress state of zones of low-amplitude neo-tectonic deformations (see appendices 1 and 2). The results of complex remote methods make it possible to reconstruct the tectonic model of the study area, which was formed mainly at the paleo-tectonic stage. The joint use of information on the tectonics of the object at different geological times, which significantly differs in the resolution capabilities of the methods for the amplitudes of dislocations in the upper and lower parts of the sedimentary cover, makes it possible to more fully reconstruct the model of each pool within the area of the field. The high efficiency of using the results of aero-space observations is due to their high resolution, which in favorable conditions is at the level of **<50 cm**; 3D survey with deep processing and the use of spatial migration makes it possible to identify faults with a vertical amplitude of 2–4 m [31, 71, 72].

Geodetic surveys using satellite equipment from Trimble Navigation and software processing packages from GPSurvey and TGOffice make it possible to record low-amplitude deformations. The use of this complex in the Surgut region of Western Siberia in the zone of frequent violations of the oil pipeline made it possible to establish the causes of pipeline ruptures and draw the following conclusions [57]:

1. There is a connection between the movements of large lithospheric blocks - mega blocks, which are in constant motion relative to each other, and movements within a set of small structural blocks. Within small blocks, systems of regional and local tectonic faults cause tectonic movements.

2. Local geodynamic structures manifest themselves as local faults in the sedimentary cover. On the surface, these are lineamentum; within their limits, increased fracturing, anomalies of the magnetic field and gamma background, and an increased concentration of radon and its decay products are manifested. The width of the identified geodynamic structures ranges from 100 to 500 meters, and the concentrated manifestation of the dynamics of deformation processes occurs in the zones between the blocks. The main zones of deformation concentration are confined to the intersection of local faults.

A similar “coincidence” of the places of manifestation of tectonic movements was noted by many researchers. In particular, the confinement of low-amplitude tectonic movements to practically the same places equally distant within 50 km from the ancient tectonic fault was recorded by Japanese researchers, who used geodesic studies during the period 1900-1975 [39]. Such local low-amplitude tectonic movements have a very significant effect on changes in the hydrodynamic connectivity of oil and gas pools in the process of their development (see appendices 1 and 2).

The presence of low-permeable barriers within oil pools in the Perm region was recorded according to radio wave geointroskopiya mezhskvaliving space data; their presence and position were confirmed as a result of the development of these pools [36].

Based on the results of drilling and investigation of exploration and development wells, it is possible to refine the positions of **LPB1**s and **SVC**s within the pool using the features that are shown in Table 1. These features are obtained on the basis of the results of studying a large number of gas and oil pools, some of which are given in appendices 1 and 2.

Table 1: Indications of the presence of **SVC**s and **LPB1**s in oil and gas pools.

The indications	Gas pools	Oil pools
1. The differences in physicochemical properties of formation fluids in different parts of the pool before the beginning of the pool production*/.	+	+
2. The jumping change of level GWC, GOC or WOC in different parts of the pool before its development1/.	+	+
3. Uncompleted hydrocarbon saturation rocks between water and GWC or WOC2/.	+	+
4. The preservation of formation pressure gradients between different parts of the pool after the gas production termination.	+	
5. The constant formation pressure gradients between different parts of the production pool or their increase at different gas production rates.	+	
6. Anomalous deep cones of depression inside gas production zones and preservation Pf0 inside zones where producing wells are absent3/.	+	
7. Increase in gas flow resistance inside the developed pool.	+	
8. Increase in the value of current drainable gas volume inside the developed pool - Vdri during the initial stage of development and decrease Vdri after recovery of more than ~30% of initial gas reserves.	+	
9. Practically, the gas regime of pool development by depletion drive.	+	
10. ORF, CRF and GRF magnitudes are systematically less than the projected values, which are calculated in the framework of the FM14/.	+	+
11. Anomalous decrease of specific condensate content inside zones of gas production by depletion drive.	+	

12. Local jumping bottom water breakthrough by reduction of the formation pressure in the pool.	+	+
13. Anomalous dynamics of Pwi change inside water-bearing zones of developed gas pool: the presence of stagnant zones; jumps of Pwi on the area and in the time gas recovery; practically equal formation pressure in the gas production zones and in some water-bearing zones of the pool.	+	
14. Abnormally large productivity of wells located close by neo-tectonic faults from the beginning of the pool development and lowering productivity by dropping Pf0.	+	+
15. Abnormally high speeds and not predicted trajectories of movement of the injected fluids.	+	+
16. Anomalous pressure-build-up curves.	+	+
17. Stagnant zones, which are fixed by drilling of infill wells and drain branch holes of producing wells.	+	+
18. ORF, CRF and GRF dependence on quantity and arrangement of producing and injection wells.	+	+

Notes: +/the typical indication.

*/ The presence of this indication is sufficient to detect the presence of **LPB1**s in the oil pool if the fluid samples under study are obtained from productive deposits with similar reservoir properties.

[1]/ **GWC**, **GOC**, **WOC**– gas-water contact; gas-oil contact; water-oil contact, accordingly.

[2]/ In these rocks, the water content is higher than the values of maximum irreducible water saturation - S_{wcrit} in productive deposits of this pool with similar reservoir properties; during hydrodynamic studies, water with low **HC** content enters the well.

[3]/ P_{f0}; P_{fi} -initial and current formation pressure in production zones, accordingly; P_{wi}- current formation pressure in the water-bearing zone.

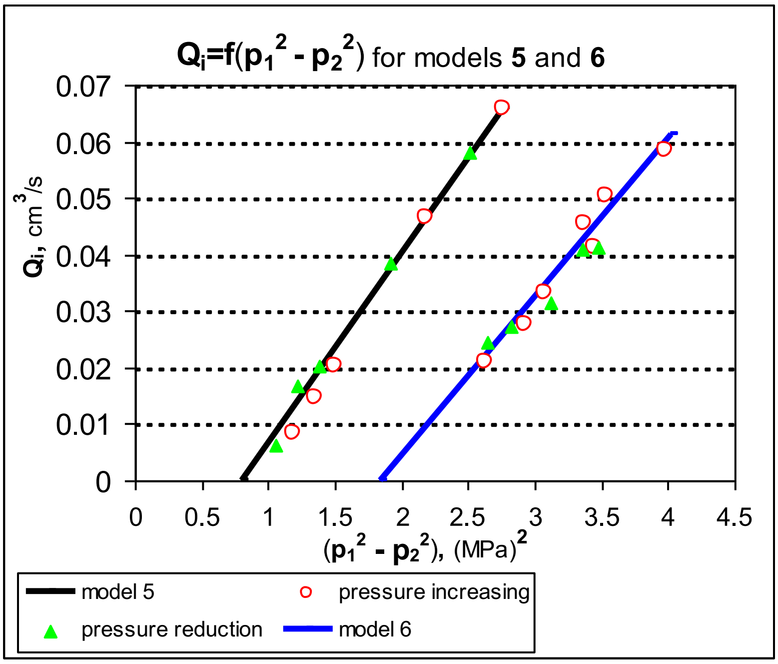
[4]/ **ORF**, **CRF** and **GRF** – oil, condensate and gas recovery factor, accordingly.

1.2. Initial pressure gradient during fluid flow through low-permeable porous media.

Section 1 and Appendix 1 present the results of field observations, which recorded that the gas flow through low-permeable porous media occurs only at pressure gradients above a certain initial value, which is called the initial pressure gradient - **IPG**. The presence of **IPG** and an increase in the **IPG** value with a decrease in formation pressure during gas production significantly affects the efficiency of gas pool development systems. In this regard, laboratory studies were carried out to understand the nature of this phenomenon.

1.2.1. Results of laboratory experiments.

In laboratory conditions, for the first time, the presence of the initial pressure gradient for gas flow in low-permeable porous media was established under the guidance of academician A. Kh. Mirzadzhanzade during research on artificial porous media models. The models from a mixture of sand and clay with different water-saturation content were prepared in a 1.2 m long pipe. The laboratory equipment made it possible to measure the permeability of the models at different values of effective overburden rock pressure - $p_{ef.}$ [18, 22]. In the experiments, it was found that in some gas-water-saturated porous media containing only irreducible water - S_{wi}, there is no gas flow until the difference in pressure at the input and output of the model reaches a certain threshold value ΔP. After exceeding the ΔP value, the relationship between the gas flow rate through the model q and the difference $\left| p_1^2 - p_2^2 \right|$ can be adequately described as a linear one. The threshold value of ΔP in experiments differed significantly depending on the relative content of clay, sand and irreducible water (see Fig. 8).



Figures 8: Indicator diagrams on models 5 and 6. Model 5 contained 75% sand and 25% clay with $S_{wi} = 0.40$, **IPG** for gas flow =0.298 MPa/m; model 6 contained 70% sand and 30% clay at $S_{wi} = 0.40$, **IPG** for gas flow =1.038 MPa/m [18, 22].

With an increase in the p_{ef} value, the **IPG** value for gas flow in model 6 increased significantly (see Fig. 9).

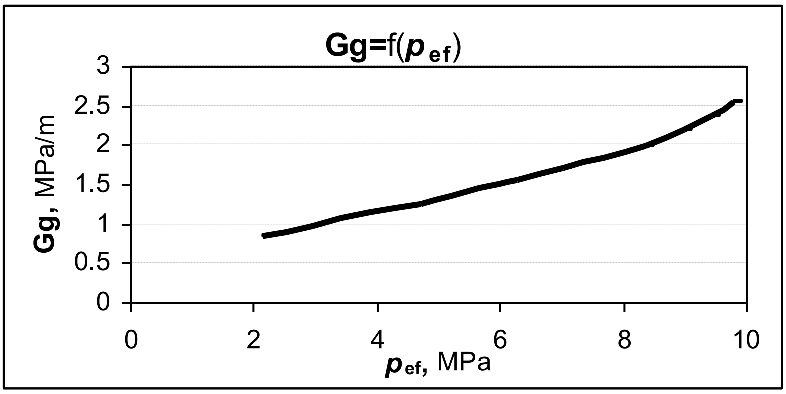
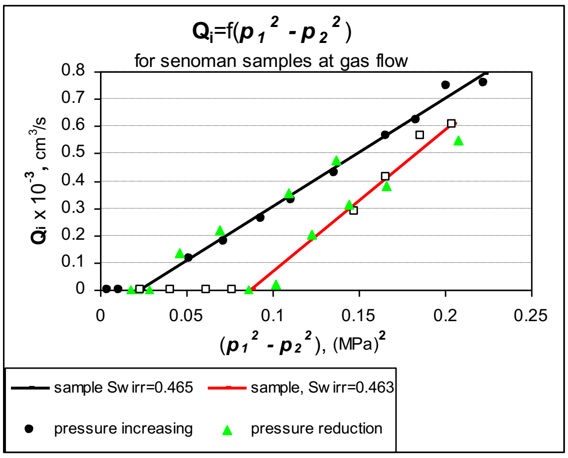
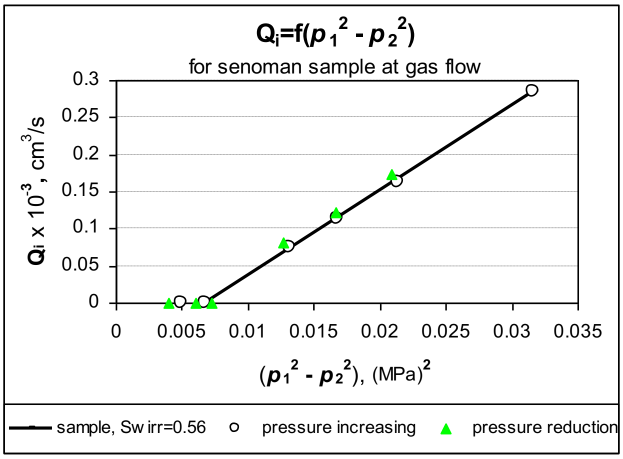


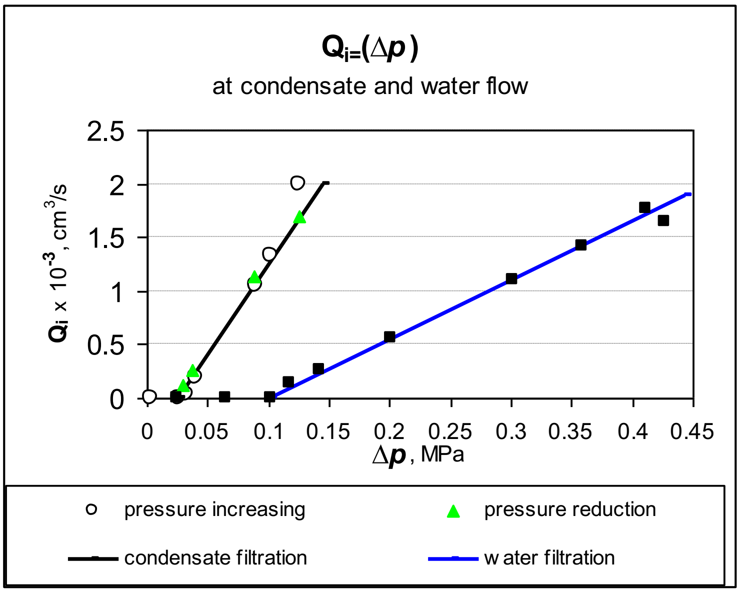
Figure 9: The example of **Gg=*f* (*p*$_{ef}$)** dependence [18, 22].

Experimentally, the existence of **IPG** in the gas flow in natural porous media was established on core samples [58]. The core samples were taken from exploratory well No.127, drilled using waterless drilling mud in the Cenomanian gas pool of the Urengoyskoye field. The samples contained only initial water saturation in situ. The water content in the core samples was monitored by measurements of electrical resistivity - **ER** at in-situ conditions and were compared with electrical logging data in the core recovery interval. In all experiments, the core **ER** was the same in both cases. The samples were also weighed, and **ER** was measured before and after each experiment, in which gas or condensate filtration was investigated to make sure that during the experiment, there was no loss of initial water and its distribution. The rock cores were comprised of clayey siltstones and a thin alternation of sandy argillites and clayey siltstones. The core water saturation was within the range **of 0.43÷0.74,** while the porosity was in the 0.22÷0.25 interval. The permeability of dried samples after experiments was ~**2** md. The research used natural gas and condensate with porous media, and NaCl solution with mineralization of 20 g/liter as model of formation water. Some results of these experiments are shown in Figure 10.





A). B).



C).

Figure 10: Indicator diagrams on core samples with an initial pressure gradient in the filtration of gas (A, B), condensate and water (C). [58].

The data show that the curves of gas flow rate q= f ($p_1^2 - p_2^2$) are practically the same in the cases of the pressure difference growth and decrease**.** Consequently, in the experiments, there were no hysteresis phenomena and redistribution of irreducible water, which was confirmed by the results of measurements of **ER**. The core **ER** values did not change before and after the experiments. This means that gas and condensate flow through the low-permeable samples does not irrevocably change irreducible water distribution in the core. Consequently, during the movement of gas and condensate in these samples, there was no breakthrough extrusion. The coherent gas phase in low-permeable gas-water-saturated rocks was formed only when the pressure gradient was higher than the **IPG** value; after the pressure gradient was reduced, the gas connection in the pores was again broken. The gas was probably preserved as separate bubbles. The measured **IPG** values required for gas filtration in clayey gas-water-saturation siltstones were within the range **0.03÷0.6** MPa/m and for condensate filtration **~20** MPa/m. For water movement in the gas-water-saturated sample, pressure gradients greater than **~60** MPa/m were necessary. In cores presented by the alternation of sandy argillites and clayey siltstone rocks for gas filtration, the **IPG** value was determined by the clayey siltstone content. The data presented show that, all other things being equal, the values of **IPG** during the movement of condensate and water in the gas-water-saturated low-permeable porous media are much greater than during only gas flow. It should be noted that the studies of the processes of movement of condensate and water in low-permeable core samples were carried out under conditions when the cores contained gas and irreducible water. Accordingly, two-phase filtration took place. The data presented in Fig. 8 and 10 reflect these relationships only qualitatively; they are valid only for the results obtained in the described experiments. With a change in the content of irreducible water and gas and **HC** properties, these ratios will change. Similar results were obtained in experiments with the other low-permeable terrigenous and carbonate rocks. In some samples, **the IPG** value for gas flow was not fixed at low effective overburden rock pressure - p_{ef} values, but the **IPG** was fixed with the p_{ef} values increasing [7]. Accordingly, it is likely that in some low-permeable rocks within the developed gas pools, when the formation pressure drops, the **IPG** values increase and, accordingly, the volume of stagnant zones also increases. As a result, a low completeness of gas recovery is caused [50].

The results of laboratory studies and field observations, in particular, during the gas flow through the lithological barrier (see Fig. 6), are consistent in terms of the presence and magnitude of **IPG**. In the lithological barrier, which is composed of compacted rocks, there is no increase in the **IPG** value with a decrease in formation pressure in the pool; a significant increase in **IPG** with increasing p_{ef} is recorded in the model (see Fig. 9) and takes place during the development of gas pools (see Appendix 1). Accordingly, during the development of pools in the depletion drive, there are significant differences in the dynamics of gas flow in barriers that have formed in different natural conditions.

Liquid flow through a single **LPB** occurs only if the pressure gradient exceeds several tens of MPa/m; therefore, in oil pools, each **MSB** in most cases constitutes a separate reservoir [18, 58].

1.2.2. The probable reasons for the presence of an initial pressure gradient during gas flow in a low-permeable porous medium.

If there is a coherent gas phase in a porous medium, then there is no reason for the appearance of an initial pressure gradient during gas flow. The appearance of **IPG** during gas flow is very likely if the gas does not form a connected phase, for example, if the narrowest parts of the pores are filled with water. Under these conditions, the gas is distributed in the form of bubbles, which are separated by blocking irreducible water. For gas flow, part of the blocking water needs to be moved to ensure gas connectivity. Depending on the content of irreducible water and its distribution, as well as on the pressure gradient, various involvement of blocking water in the movement is possible. In particular, water can be displaced into pores that contain gas and in which the water content is less than critical value. (In rocks that contain gas or oil and water, the critical water saturation value corresponds to the maximum water content that is held by capillary forces; under these conditions, in such a porous medium, there is a single-phase gas or oil filtration.) At small pressure gradients, water in these pores will be retained by capillary forces. In this case, microlocal two-phase filtration occurs. After decreasing the pressure gradient, the water again overlaps the narrow parts of the pores under the action of capillary forces and due to the elasticity of the gas bubbles that are pinched in the pores. If the water content is higher than the critical value in a porous medium, then, at large pressure gradients, water will be involved in the usual two-phase flow and, after a decrease in the pressure gradient, less water will remain in the porous medium (see Fig. 11).

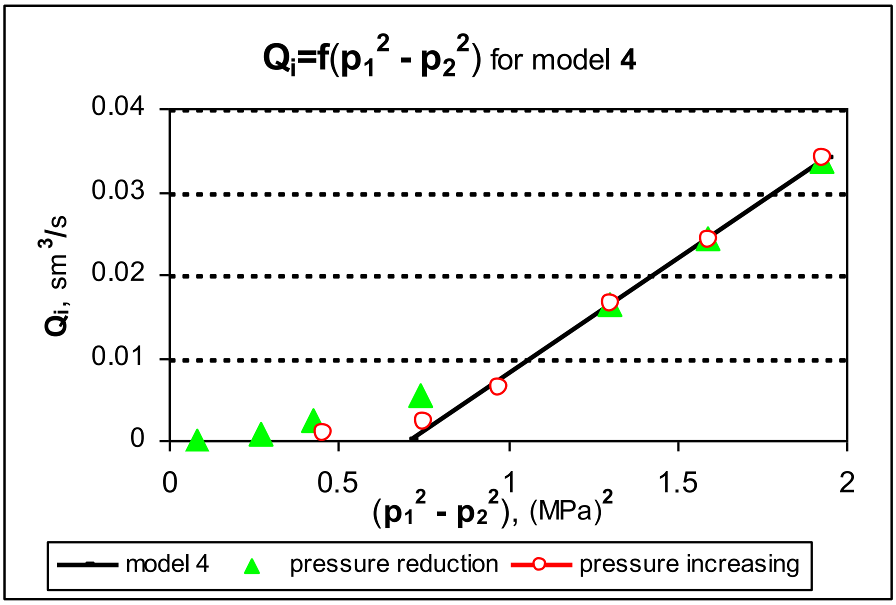


Fig. 11: Indicator diagram on model 4 with an initial pressure gradient in the filtration of gas [4].

In model M 4, at the beginning of the experiment, the water content exceeded the S_{wi} value. When comparing the results of studies with a gradual increase in the pressure gradient and subsequent ones with a decrease in the pressure gradient for this model, changes in communication parameters of flow rate q=f($p_1^2 - p_2^2$) were recorded. After the gas breakthrough, there were changes in the water distribution in the model and a decrease in the **IPG** value, in this model, from 0.25 MPa/m to ~ 0.07 MPa/m.

Studies of the features of filtration processes in the development of gas and oil pools in shale and low-permeable dense rocks, demonstrated the same qualitative results, and similar reasons for the appearance of a threshold pressure gradient - **TPG** at relatively low pressure gradients were proposed [75]. The following was investigated: in an ultra-low permeable cores displacement experiment, simulated oil and water were used as fluids to measure and analyze the **TPG** for both a single- and biphasic fluid flow in development, such as oil pools. The study indicates that different types of fluids give a different **TPG** versus permeability power function dependence. The increase in the effective stress on the rock is that the permeability will decrease, so fluid flow resistance will increase accordingly. The study discussions also indicate that, due to the capillary pressure and the Jamin effect, the **TPG** for the biphasic oil and water is greater than that for the single-phase flow. The molecular force between solids and liquids surfacing in the low-permeable rocks is a contributing factor in the cause of non-Darcy flow. The absence in these experiments of the reverse process of fluid flow with decreasing pressure gradients, as well as data that confirm the preservation of the structure of the samples and the distribution of fluids in them, does not allow us to evaluate the significance of the probable changes of the relationship between the filtration rates and the pressure gradients due to violations of the initial conditions of the experiments. The data in Figures 2 and 10 shows that it is impossible to identify the concept of the **TPG** and the initial pressure gradient for the movement of gas through low-permeable rocks containing gas and only irreducible water. When the pressure of a breakthrough in the gas-water-saturated rocks or water-saturation is more than the critical S_{wi} value, changes in their inner structure or water content occur. After a gas breakthrough, the initial pressure gradient required for gas movement in such rocks decreases or even becomes zero. Gas breakthroughs led to a decrease in the **IPG** value. The assumption of the identity of the breakthrough pressure and the phenomenon of the initial pressure gradient during gas filtration through low-permeable productive deposits in gas pools does not correspond to the results of field observations.

The initial pressure gradient for gas flow exists when gas is displaced by water from low-permeable porous media in which different pores have different cross sections. The presence of **IPG** is due to differences in capillary pressure in different pores. Gas flow will begin after squeezing out capillary-retained water. Thus, if the gas phase is incoherent, then the gas flow will begin only after overcoming the resistance to displacement of the irreducible water to form a coherent gas phase. Accordingly, one of the factors that lead to the appearance of an initial pressure gradient for gas flow in low-permeable porous media that contain gas and irreducible water may be the Jamen effect. When gas is displaced by water, capillary and pressure forces interact. Accordingly, depending on the magnitude of the pressure gradient, the contribution of capillary and pressure forces changes. At large pressure gradients, the effect of capillary impregnation is suppressed by the pressure displacement of gas from the largest pores. Water will flow into the largest pores, increase pressure in them and block gas in shallow pores. The remaining gas will be distributed in a porous medium in the form of separate bubbles. Due to the compressibility of the gas, the displacing water does not enter the shallow pores, and will move mainly through large pores, from which the gas is displaced by water. Partial recovery of gas from small pores will occur when the pressure in large pores decreases and a pressure gradient is created to move blocking irreducible water from small pores to large pores. At small pressure gradients, due to the predominance of capillary imbibition, the water remains in a capillary-retained state. When the maximum volume of water for a specific porous medium is contained, almost full displacement of gas from large pores will begin. In this case, displacement will also occur at small pressure gradients, since water displacing the gas will move along the water films. Accordingly, pressure displacement of gas by water will occur when the injected water does not have time to distribute in accordance with the action of capillary forces. This condition is realized at a certain value of the initial pressure gradient, which depends both on the properties of the porous medium and the water content in it. The process of gas displacement by water at small pressure gradients is satisfactorily described by the Rapoport-Lis equation [9, 23], which takes into account the action of capillary forces. With large pressure gradients, it is necessary to take into account the initial pressure gradient to displace gas from small pores. The presence of an initial pressure gradient in low-permeable rocks in gas pools is probably due to the difference in the current thermodynamic conditions from the initial conditions during the formation of the pools. The results of field observations prove the existence of an **IPG** phenomenon for the gas movement in natural pools [18]. The above experimental data prove the presence of **IPG** in some low-permeable gas-water-saturated core samples in detailed laboratory studies. The mechanism of the **IPG's** appearance in the course of gas flow in porous media with irreducible water is not clear yet.

1.2.3. Changes in the filtration resistance of pools with a decrease in formation pressure.

Changes in the filtration resistance of pools with a decrease in formation pressure occur as a result of compaction of low-permeable rocks, which are contained in part of **LPB1**s and **SVC**s. This compaction causes an increase in **IPG** as gas flows through **LPB1**s and new low permeable barriers that have arisen in **SVC**s. These changes take place practically during the development of all gas pools in the depletion drive. Changes in **IPG** during compaction of low permeable rocks have been experimentally confirmed (see Fig. 9). As a result, stagnant zones are formed in **MSB**s, in which there are no producing wells, and the volume of stagnant zones increases (see Appendix 1). If further growth of formation pressure occurs in such pools as a result of the injection of any fluids, the plastic rocks in **LPB1**s and **SVC**s contain residual deformation. When creating gas storage facilities - **UGS** in depleted pools, the effect of residual deformation of **LPB1s** is most pronounced.

In 1986, they began to create **UGS** in a depleted oil and gas condensate pool at the Karadag field. The pool is located at a depth of ~4000 m in terrigenous deposits. Gas injection was started eight years after the completion of gas and oil recovery. By the beginning of the first gas injection, the formation pressure differences in different previous gas production zones were ~1 MPa. Pressure gradients between the different previous production zones and between the buffer parts of the pool remain; it indicates that different parts of the pool are separated by **LPB1**s. During the **UGS** operation, only a small part of its gas-saturated volume is employed, which we denote as $V_{g.St}$. Over the past 15 years of operation, the $V_{g.St}$ value has been significantly less than even half the pool volume, from which gas was recovered ($\boldsymbol{V_{g.0}}$) at current formation pressure in the pool**.** The ratio $V_{g.St}/\boldsymbol{V_{g.0}}$ value changed depending on the pressure of the injected gas.

Over the past 15 years of operation, the $V_{g.St}$ value has been significantly less than even half the pool volume, from which gas was recovered at current formation pressure in the pool**.** The actual volume of gas that remained in the pool by the end of its development is unknown, but the ultimate formation pressure P_{ult}≈3.6 MPa is known since, when only the **UGS** operation period is considered, the corresponding additional volume of gas in the pool is determined only by the value of the injected gas (V*). The fraction of the $V_{g.St}/\boldsymbol{V_{g.0}}$ value is determined by several factors:

• The level of residual deformation of plastic rocks, which are contained in **SVC**s and **LPB1**s;

• **SVC**s and accordingly **LPB1**s location in the pool and **IPG** values for gas flow through different **LPB1**s in the pool by different formation pressure;

• Number and location of producing and injection wells within the **UGS**;

• The value of the $V_{g.St}/V_{g.0}$ ratio decreases if the initial formation pressure P_{f0} in a pool is high and the initial formation pressure within the **UGS** is considerably lower than the P_{f0}. This is the case when using the considered depleted pool as **UGS** in the Karadag field.

Fig. 12 shows the comparison of the pool formation pressure values along its initial use of the gas pool in the depletion drive and in the **UGS** operation [18].

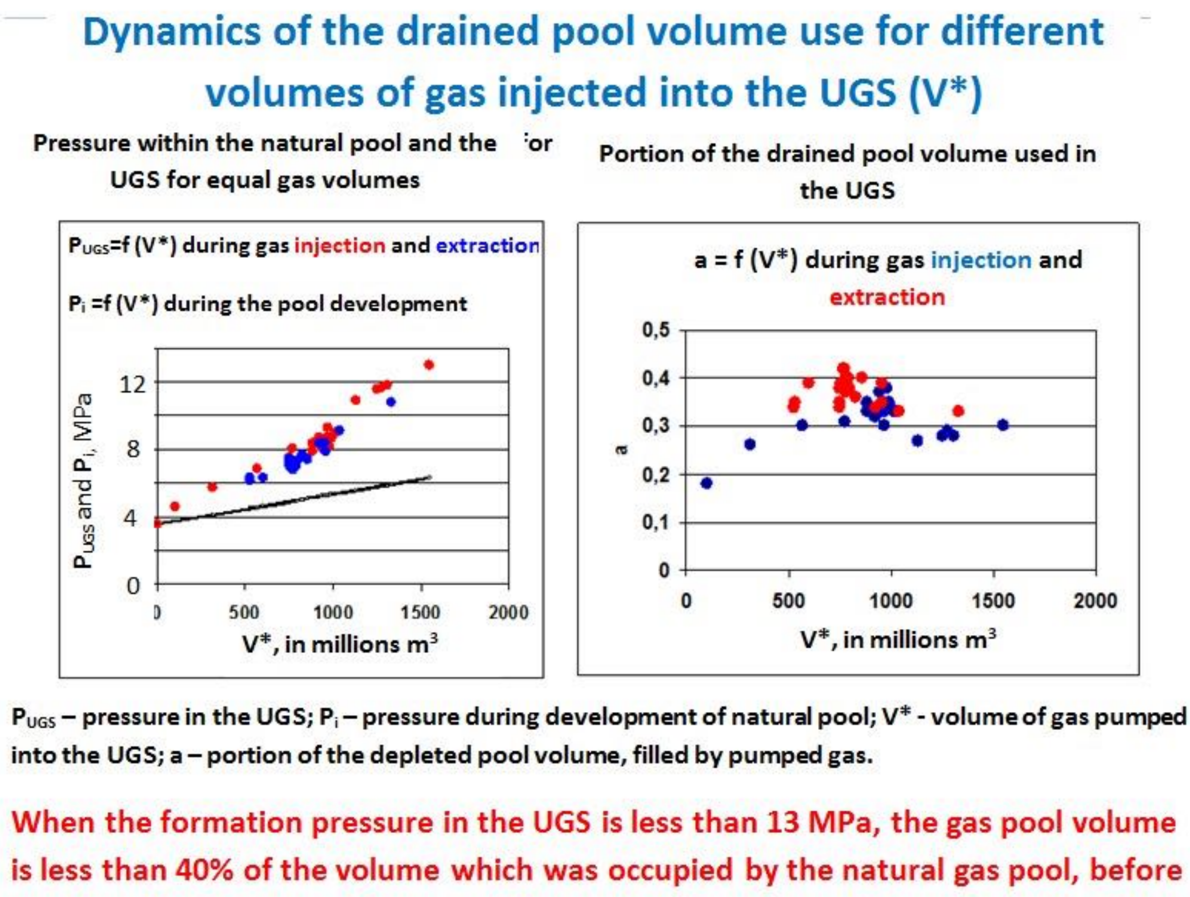


Figure 12: Dynamics of the drained pool volume use for different volumes of gas injected into the **UGS**.

Values of the $V_{g.St}/V_{g.0}$ for the operating **UGS** depends on the characteristics of injection and gas recovery regimes**.** If the current formation pressure in **MSB**s adjacent to gas injection zones is $\boldsymbol{P_{ib}}$, and a gas injection pressure $\boldsymbol{P_{in}}$, the injected gas breaks through part of the **LPB1**s to the **UGS** "buffer" blocks then at $|\boldsymbol{P_{in}} - \boldsymbol{P_{ib}}| > \boldsymbol{G_{gi} h_i}$ ($\boldsymbol{G_{gi}}$ – value of **IPG** required for gas flow through the ***i*LPB1** of thickness $\boldsymbol{h_i}$). A broken injected gas increases the formation pressure in "buffer" blocks. When gas is taken from the **UGS**, the current formation pressure in part of the "buffer" blocks remains insufficient for gas flow from them through the **LPB1**s to the production zones. As a result, at a subsequent stage, the amount of gas available for recovery decreases.

This apparent phenomenon accelerates the decrease in formation pressure in **UGS** during the subsequent gas recovery and also changes the gas trajectories for subsequent injections*,* since different formation pressures in the residual gas are stored in different **MSB**s of the UGS. Note that, when using the depleted gas pool Karadag as **UGS**, the formation pressure in the pool produced by gas injection was increased from ~4 MPa to ~12 MPa. The increase of formation pressure in the pool caused a slight decrease in p_{ef} values and in the **IPG** values in the **LPB1**s, adjacent to the gas injection zones. As a result, as the active gas volume in the **UGS** increased, there was an increase in the useful **UGS** volume (the $V_{g.St.}$ values increased from ~$0.2V_{g.0}$ to ~$0.4V_{g.0}$ at the current formation pressure). When extracting gas from **UGS**, a somewhat larger part of the value $V_{g.0}$ is systematically used, than when the gas is injected. In the initial stage of gas injection into the depleted pool, compressors were used, which provided a slow increase in formation pressure within the **UGS**. The $V_{g.St}/V_{g.0}$ value gradually increased from **~0.18** to **~0.3**. When gas was extracted from the **UGS,** part of the gas that broke through the **LPB1s** returned to the low formation pressure zones, and the $V_{g.St}/V_{g.0}$ value reached **~0.**4$V_{g.0}$. Then the gas injection pressure increased, and the $V_{g.St}/V_{g.0}$ value decreased to **~0.3** when gas was injected, and did not exceed **~0.33** at the gas recovery stage (see Figure 12). This data illustrates the Multi-scale fractured block structure of the pool and the significant differences in the properties of **SVCs** and **LPB1**s in different parts of this pool. Not taking into account these features of the internal structure of the pool led to low completeness of gas recovery during its development in depletion drive, as well as low efficiency of using the depleted pool as **UGS.** The data presented are in qualitative agreement with the results of studying the effect of effective pressure on the value of **IPG** in low-permeable models [4]. Changes in the internal structure of the pool are evident as a result of the residual deformation of clay rocks inside **SVCs** and **LPB1**s. These apparent phenomena make it practically undesirable to use depleted pools, which are located at great depths, for storing gases.

Part 2. Interaction of hydrocarbons with porous media and its effect on the completeness of oil and condensate recovery and well productivity.

2.1. The study of the problem and the use of the information received.

The interaction of **HC** with porous media changes their wettability and determines the efficiency of systems for developing oil and gas condensate pools. Wettability is the ability of a liquid to maintain contact with a solid surface, resulting from intermolecular interactions when the two are brought together. The degree of wettability is determined by a force balance between adhesive and cohesive forces [Wikipedia, 2021]. W.G. Anderson formulated the following conclusions: wettability is a major factor controlling the location, flow, and distribution of fluids in a reservoir. The core wettability will affect almost all types of core analyses: capillary pressure, relative permeability, water flood behavior, electrical properties, and simulated tertiary recovery. The wettability of originally water-wet reservoir rock can be altered by the adsorption of polar compounds and the deposition of organic material that was originally in the crude oil. The degree of alteration is determined by the interaction of the oil constituents, the mineral surface, and the brine chemistry [5, 6]. The conclusions remain the most complete. These conclusions are confirmed by numerous subsequent studies and, in particular, the results of observations on the development of a number of oil pools, which recorded differences in the properties of the produced oil in different parts of the same pool, as well as in the process of developing pools using water flooding [1, 18, 21, 24, 51, 60, 69]. All this information is only partly used in the development of most oil pools. Water flooding continues to be applied, in which, as noted in the work [1]: “Making the assumption that a reservoir is water-wet, when it is not, can lead to irreversible reservoir damage. This wetting heterogeneity can affect recovery”. The low completeness of oil recovery and the results of studying the interaction of oil with porous media led to the development of **EOR** methods and, in particular, chemical methods. At the same time, they focused on simple models of the internal structure of pools and oil properties at different stages of their development [52].

2.2. Study of the oil properties in sediments with different reservoir properties.

The **NMR** method was used to study the properties of produced oil, oil into productive deposits and residual oil in rocks with various reservoir properties during the water flooding. Work was carried out in 1993-1994 in the Numalog Israel (a subsidiary of NUMAR Corporation USA); measurements were made using a Corespec-1000 spectrometer, operating frequency ~1 MHz, **NMR** signal relaxation curves were obtained using a program developed by M. Dakhnovsky; the processing of the measurement results was performed using the **NMR** signal spectrum recovery programs developed by G. Itzkovich. The studies were conducted on collections of mainly terrigenous cores from two water-saturated reservoirs. Some of the samples were studied during initial wettability, and some after small hydrophobization of the pore surface. Samples with irreducible water - S_{wi} were filled with oil with a viscosity from ~1 to ~125 cp. The **NMR** parameters of the samples and the fluids that saturate them were measured under different conditions. The studies additionally reveal and substantiate the causes of changes in oil properties within each pool, outlining some ways to increase the completeness of **HC** recovery and well productivity [15, 18].

The **NMR** method is based on resonant absorption and emission of electromagnetic energy by a substance. The **NMR** signal is mainly determined by the content of hydrogen nuclei and their physicochemical mobility within the investigated volume. The high sensitivity of **NMR** parameters to oil properties was shown in many works **[**19, 20**].** The subsequent use of **NMR** was based on the use of more advanced instrumentation; much attention was paid to the estimation of oil viscosity, but the practical use of these results is limited. Samples of heavier oils also contain light **HC** fractions, but they are not always recorded in the corresponding spectra of relaxation times of oils. The complex composition of oil and the multifactorial dependence of **NMR** parameters on oil properties under study make it possible to qualitatively characterize the properties of oil in free volume, and especially fluids in porous media. The multi-fractional composition of oil is ambiguously reflected in the spectra of relaxation times; it is practically impossible to determine the required parameters with the required accuracy. This limits the use of deterministic methods for evaluating oil properties and determines the advisability of using indicator characteristics to identify changes in oil properties in various processes. We used the indicator method to study changes in the oil properties in a porous medium under conditions that occur during the formation of oil pools and oil recovery. As a result of the work carried out, the following was revealed:

I. When oil enters natural traps, it interacts with permeable sediments. Heavy oil components break through thin layers of irreducible water in the large pores and are adsorbed on the surface of these pores or on the electric double layer (we could not separate these effects). The adsorbed oil forms selective layers with abnormally high viscosity. The data in work [48] shows that the thickness of the main part of the film, which hydrophobizes the porous medium, is within 100 Å. Lighter oil fractions adhere to the adsorbed oil layers. The adsorption of oil violates the physicochemical balance in all trapped oil, which causes changes in the properties of the oil and in the pores in which residual water remains. The interaction of oil with porous media causes its fractionation by the Van der Waals forces, almost like in a chromatographic column. This interaction is determined by: the properties of oil; the thickness and properties of irreducible water in each pore; the specific pore surface, and the reservoir properties of deposits. The level of oil interaction with different porous media causes significant differences in the distribution of different oil components in various sediments of each pool. These differences are greater in pools that contain oils with higher viscosity, and in productive sediments with high reservoir properties (see Fig**.** 13 - 15). In gas-condensate pools, fractionations of retrograde condensate occur.

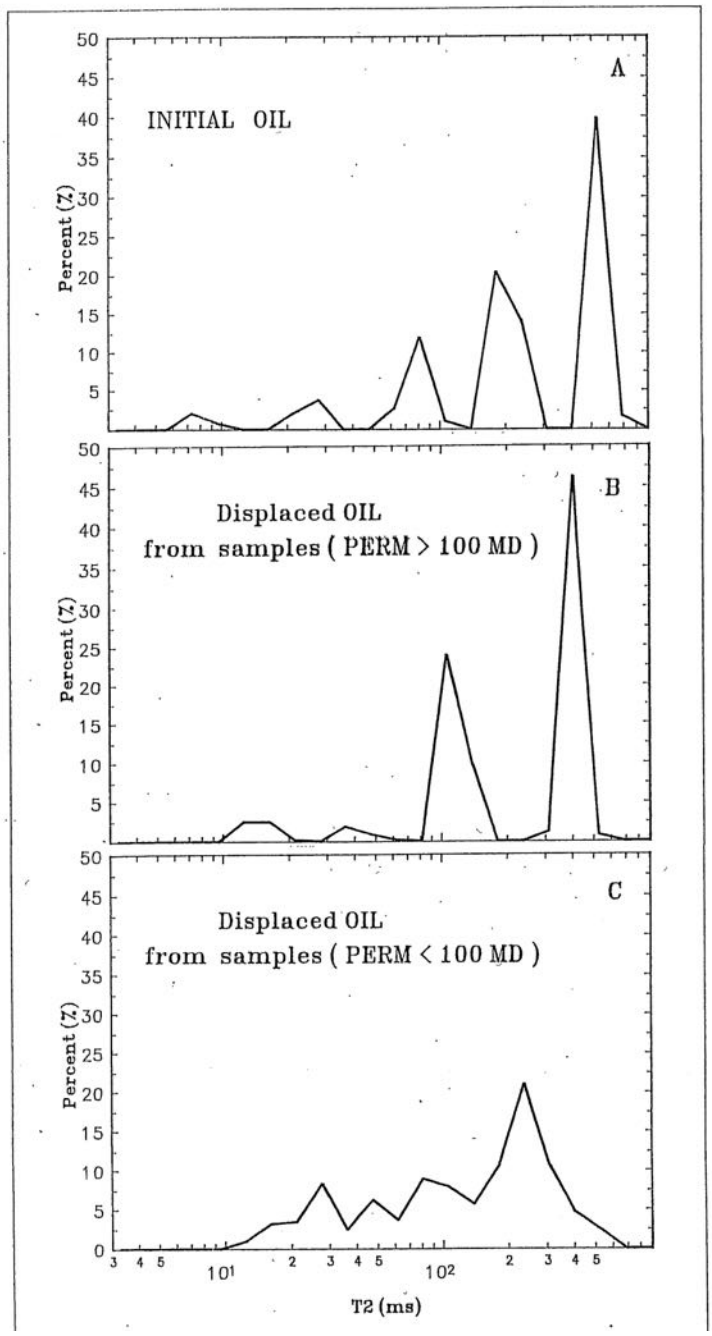


Figure 13: Relaxation time of T2 spectra of the initial oil viscosity of ~1 cp in a free volume (A); the same oil after its displacement by water from sample with K=350 md; m=0.258; and S_{wi}=0.11; S_{or}=0.25 (B); and from some samples with K=10÷70 md; m=0.178÷0.195; S_{wi}=0.17÷0.37; S_{or}=0.19÷0.36 (C). S_{wi} created at Pc=75 Psi. The displacement of oil by water was at a pressure gradient of <100 Psi/m. This condition was also fulfilled in other experiments, unless another value of the pressure gradient is given when oil is displaced by water.

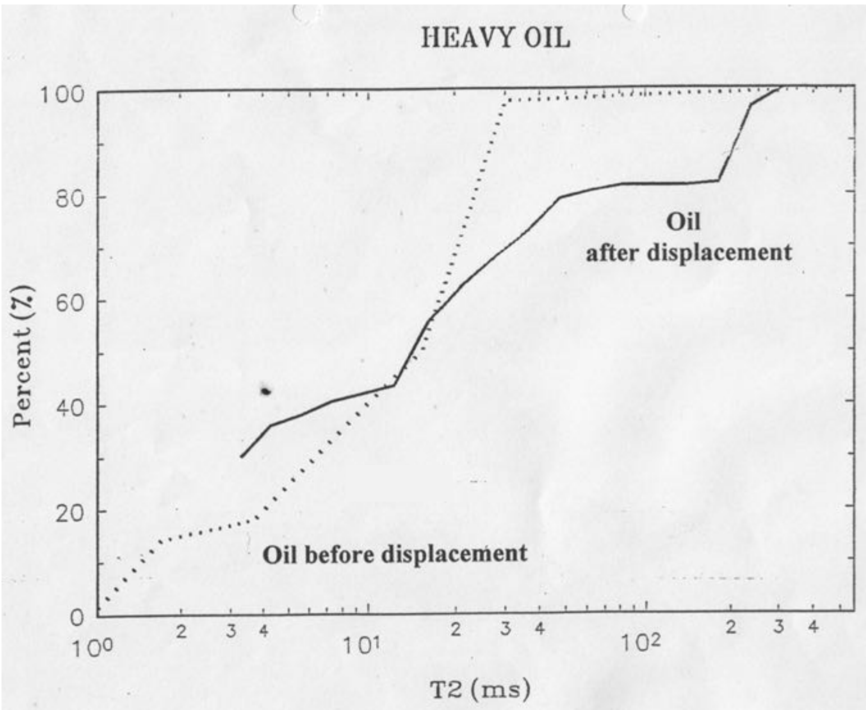


Figure 14: Cumulative curves of T2 spectra of the initial oil with the viscosity of 125 cp before displacement and the oil after its displacement by water from terrigenous rock samples with K≥100 Md and S_{wi}≤0.2 with hydrophilic surface before oil penetrated in the rocks.

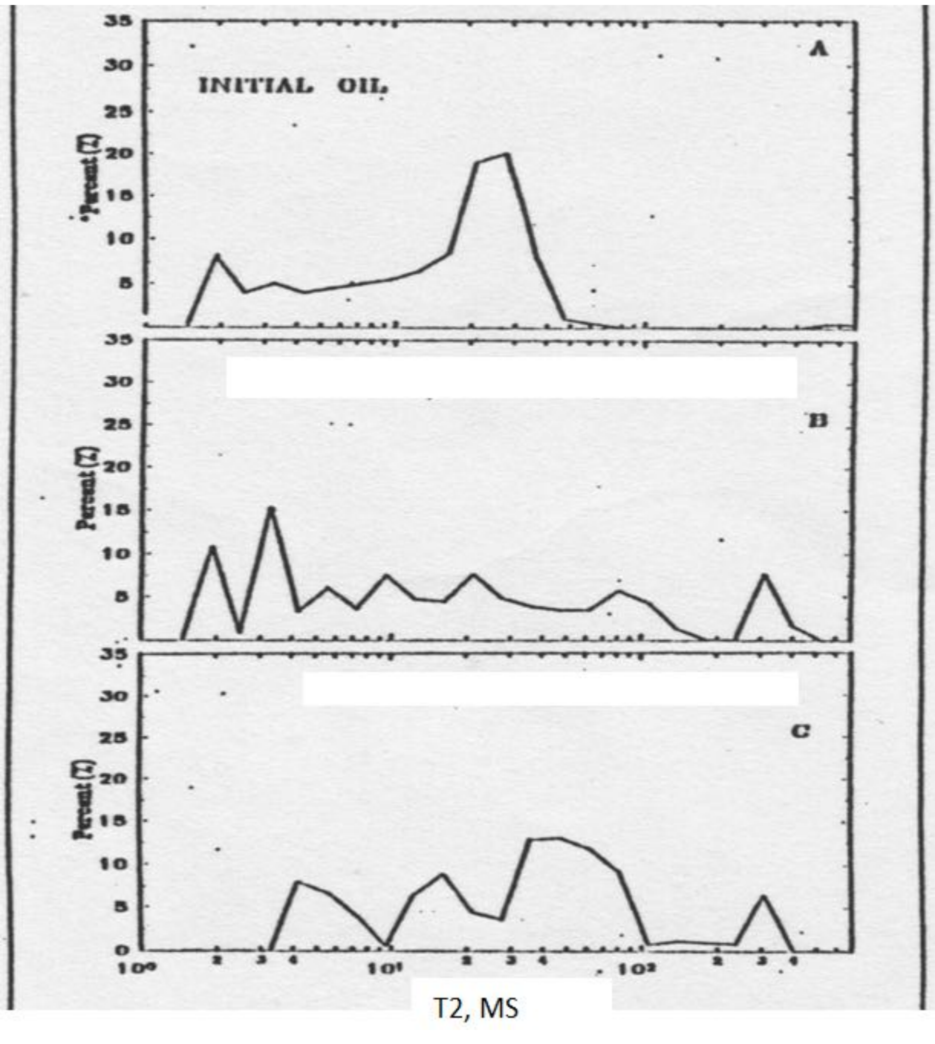


Figure 15: Spectrums of relaxation time T2 of initial oil with viscosity 125 cp (A) and the oil, which was displaced by water from samples with hydrophilic surface before oil penetrated in the rocks with K=40 md, m=0.195, S_{wi}=0.20 and K=20 md, m=0.206, S_{wi}=0.26 (B); sample with K=7 md, m=0.166, S_{wi}=0.42 (C). Irreducible water saturation was created at Pc=75 Psi.

From data in Fig. 13 - 15 follow:

1. In a porous medium with irreducible water saturation, oils with an initial viscosity of ~1 and ~125 cp are adsorbed on the pore surface, which leads to its fractionation. There are large differences in the NMR spectrum and, accordingly, in the properties of the original oil and oils that are displaced by water from rocks with different reservoir properties.

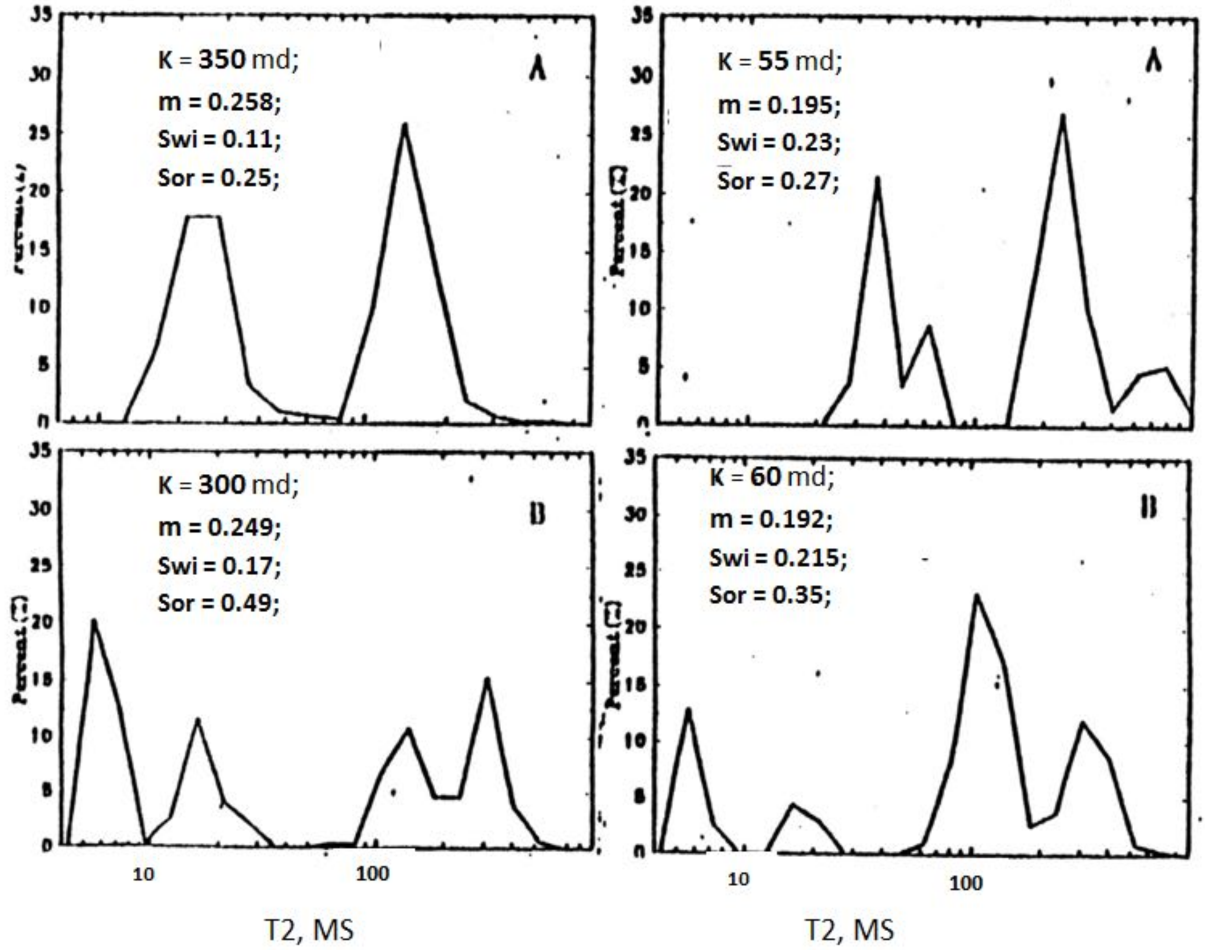
2. The results of data in Fig. 13 show that initial and displaced oils differ significantly from each other both in the region of short and long relaxation times**.** The light oil displaced from the sample with K=350 md (Fig. 13B) does not contain relatively heavy oil fractions**,** which are recorded in the **NMR** spectrum of oil in the free volume with T2~7 MS (Fig. 13A); at the same time, there is an increase in the proportion of light oil fractions with T2>100 MS. The oil displaced from the K<100 md samples is heavier than the oil from the K=350 md sample (see Fig. 13C).

3. Initial oil with viscosity ~125 cp is adsorbed on the pore surface; the displaced oil from the samples with K>100 md and $S_{wi}\leq 0.2$ differences in the **NMR** spectra of the original oil in the region of T2<10 MS and in the region of T2≥50 MS and especially at T2≥200 MS, where the signal in the original oil was practically absent (see Fig. 14). In the **NMR** spectrum of the displaced oil, the minimum values are T2~4 MS; in the **NMR** spectrum of oil in the free volume, more than 15% of the signal is by T2 <4 MS, which characterize the presence of heavy oil components.

4. Heavy oil fractions are recorded in the oil displaced from samples with the K=40 md and K=20 md (Fig. 15B). This is due to the different, selective levels of adsorption of heavy oil components in rocks with different reservoir properties. The oil that was displaced from the sample with K=7 md did not fix the heaviest components, probably due to the limited capabilities of the spectrometer used in the study of the complex composition of oil.

Consequently, when using water flooding, residual oil in sediments with different reservoir properties has different physicochemical properties and a different distribution of heavy and light oil components. The data presented are consistent with the results of field observations, which recorded differences in the properties of the produced oil within the same pool [18, 40, 43, 76].

II. The influence of the initial wettability of rocks with different reservoir properties when oil is displaced by water with different pressure gradients on the properties of residual oil and its content can be seen from the data in Fig. 16 and in Table 2. For a clearer idea of the properties of the residual oil, the original oil was displaced by water with a paramagnet, which excluded the **NMR** signal from this water and partially from the irreducible water.


K = 350 md;
m = 0.258;
Swi = 0.11;
Sor = 0.25;
A
K = 55 md;
m = 0.195;
Swi = 0.23;
Sor = 0.27;
A
K = 300 md;
m = 0.249;
Swi = 0.17;
Sor = 0.49;
B
K = 60 md;
m = 0.192;
Swi = 0.215;
Sor = 0.35;
B
Percent (%)
10
100
T2, MS
T2, MS

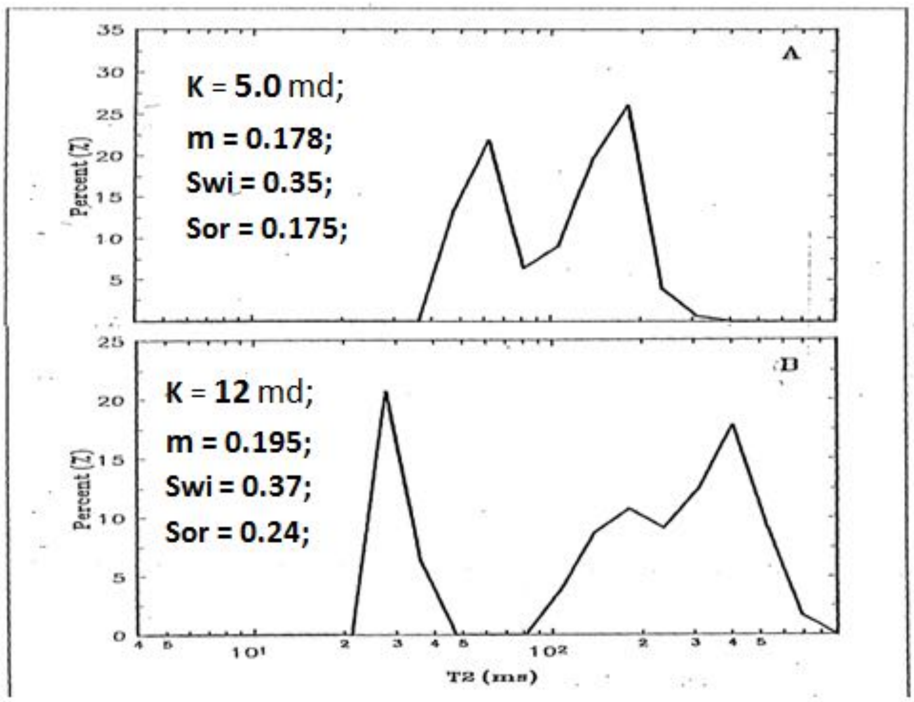

A
K = 5.0 md;
m = 0.178;
Swi = 0.35;
Sor = 0.175;
B
K = 12 md;
m = 0.195;
Swi = 0.37;
Sor = 0.24;
Percent (%)
T2 (ms)

Figure 16: Relaxation time spectra of T2 residual oil with an initial viscosity of ~1 cp in sandy-clay samples with various reservoir properties when oil is displaced by water. A- Samples with initial hydrophilic pore surface; B- Samples with initial hydrophobic pore surface.

The data show that:

1. The relaxation time spectra and, accordingly, the properties of the residual oil when oil is displaced by water in all the studied rock samples are significantly different from the properties of the original oil in free volume (see Fig. 13). These differences are due to the fractionation of oil in a porous medium and presence or absence of adsorbed heavy oil components. The properties of residual oil in the studied samples are different in the sediments with different reservoir properties and different wettability of the pore surface before they are filled with oil.

2. Adsorbed oil is mainly fixed in rocks with $S_{wi} \leq 0.3$, and its content increases with increasing reservoir properties of the deposits. In part rocks with a high content of irreducible water, partial fractionation of oil is fixed, but the proportion of adsorbed oil is small;

3. The increase in S_{or} values occurs in the samples with a hydrophobic pore surface at $K \geq 60$ md. The S_{or} values are significantly higher than in similar samples with an initially hydrophilic pore surface. In samples with a hydrophobic pore surface, the S_{or} values are the greater, the higher their reservoir properties (see Table 2). The relaxation time spectra of the studied samples with relatively high reservoir properties and initial hydrophobic pore surfaces fix the presence of a T2 peak with relaxation times <10 MS; it is the presence mainly of adsorbed oil components, which is not recorded in samples with lower reservoir properties and in samples with initial hydrophilic pore surface. It occurs under conditions where the irreducible water content was higher in samples with a hydrophobic pore surface, since the irreducible water in them was simulated at a lower capillary pressure (45 Psi).

4. The presence of adsorbed and adhered oil fractions (T2<~20 MS) is clearly recorded only in the two samples with an initially hydrophilic pore surface with K=350 md and K=50 md. In the sample with K=350 md, the presence of two enlarged residual oil components is recorded: **I-** with T2=10÷30 MS and **II-** with T2=70÷300 MS. In samples with a hydrophobic pore surface and K=300 md and 60 md, peak **I** is also recorded. This peak probably characterizes mainly the content and properties of the adhered oil components**.**

5. In the samples with low reservoir properties, with an initially hydrophilic and hydrophobic pore surface in the residual oil, only light oil fractions are practically recorded; the main **NMR** signal is recorded from trapped oil, whose properties are similar to the properties of recovered oil from hydrophilic rocks with $K \geq 100$ md (see Fig. 13). In the sample with a hydrophobic pore surface and K=12 md, the **NMR** signal from adhering oil components is probably recorded (it is the presence of several large pores in this sample), the majority of the **NMR** signal is due mainly to trapped oil.

Table 2: The values of S_{or} when oil is displaced by water at various pressure gradients in samples with initially hydrophilic and hydrophobic pore surfaces.

Viscosity of oil before filling the sample, cp	K, md	m	Swi*	Initial wettability	Pressure gradient when oil is	Sor

					displaced by water, Psi/m	
~1	350	0.258	0.11	Water-wet	≤100	0.25
~1	55	0.195	0.23	Water-wet	≤100	0.27
~1	50	0.205	0.165	Water-wet	≤100	0.23
~1	5	0.178	0.35	Water-wet	≤100	0.175
~1	300	0.249	0.17	Oil-wet	>100	0.49
~1	80	0.178	0.20	Oil-wet	>100	0.36
~1	60	0.192	0.215	Oil-wet	>100	0.35
~1	60	0.182	0.17	Oil-wet	>100	0.315
~1	12	0.195	0.37	Oil-wet	>100	0.24
~1	10	0.195	0.36	Oil-wet	>100	0.19
~1	0.36	0.113	0.56	Oil-wet	>100	0.21
~2.9	>100	0.214	0.14	Water-wet	≤100	0.2
~60	>100	0.214	0.14	Water-wet	≤100	0.4
~4.5	350	0.258	0.11	Water-wet	≤100	0.25
~4.5	3	0.18	0.4	Water-wet	≤100	0.17
~125	40	0.195	0.2	Water-wet	≤100	0.48
~125	20	0.208	0.26	Water-wet	≤100	0.29
~125	7	0.166	0.42	Water-wet	≤100	0.185
~1	30	0.164	0.165	Water-wet	>100	0.55
~1	35	0.21	0.19	Water-wet	>100	0.445
~1	10	0.184	0.35	Water-wet	>100	0.205
~1	1	0.102	0.42	Water-wet	>100	0.24
~1	50	0198	0.19	Water-wet	>100	0.52
~1	20	0.213	0.27	Water-wet	>100	0.23
~1	5	0.169	0.47	Water-wet	>100	0.205

*/ S_{wi} values for rocks with initially hydrophilic pore surfaces at Pc=75 Psi and with hydrophobic pore surfaces at Pc=45 Psi.

The data in Table 2 characterize the minimum values of the residual oil content during water flooding, since they were obtained under the conditions of water movement directly into the studied samples. This is important when assessing the S_{or} values in sediments with low reservoir properties in heterogeneous sections and during the movement of injected water through **SVC**s, when oil displacement by water occurs mainly from rocks with the highest reservoir properties in the section.

Differences in the properties of produced and residual oil were shown in 1991 [63], but the reasons for these differences were not given; probably, this was the reason that these results were not used in the development of oil pools for a long time.

The scope of our research on oil displacement by water is very limited (all results are given in [18]), but they show that the completeness of oil displacement by water significantly depends on the properties and internal structure of productive deposits, oil properties and pressure gradients during water flooding, as well as when using **EOR** methods. Since the internal structure of productive deposits is determined by their genesis, it is not enough to characterize these deposits by average values of porosity, permeability and irreducible water content. Without taking into account the large-scale heterogeneity of pools, information on the values of m, K and S_{ir} is not sufficient to characterize individual interlayers in the section. This follows, in particular, from a significant difference in the values of $\mathbf{S_{or}}$ even under favorable conditions of displacement by water. It is advisable to choose a method or reagents when using chemical **EOR** methods, taking into account the properties of productive deposits and residual oil in a particular part of the pool, where the main volume of residual oil reserves is contained in sediments of a certain type according to reservoir properties (see Appendix 2).

The presented data on high $\mathbf{S_{or}}$ values when oil is displaced by water using large pressure gradients are consistent with the results of observations of gas displacement by water. The results of neutron logging observations during the development of gas pools in highly porous and highly permeable terrigenous deposits showed that gas displacement by water occurs practically only in deposits with K≥0.2 D. The values of the residual gas content - K_{gi} are higher in the highest permeable deposits and amount to ~0.055 at m~0.21 and K~0.2 D up to ~0.13 at m≥0.27 and K≥~1.0 D. These K_{gi} estimates were obtained using a spectral version of neutron logging [12]. Fig. 17 shows the generalized curves of gas displacement by water (in relative units of initial gas content K_{gi}/K_{go}) in formations with K≥~1.0 D.

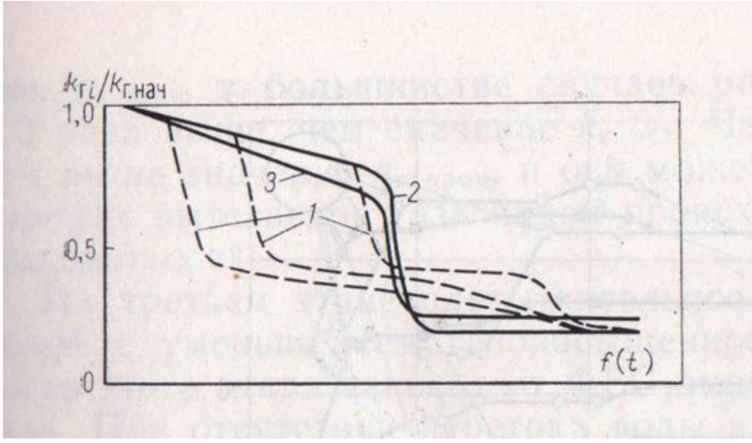


Figure 17: Generalized curves of gas displacement by water in terrigenous deposits. 1-2 breakthrough and uniform displacement, respectively; 3 - uniform displacement for rocks with K~0.3 D.

From the data in Fig. 17, it follows that gas displacement by water can occur in 2 main regimes of displacement: uniform and breakthrough. Uniform displacement is usually observed in water encroachment pool areas where there are no low permeable rocks between water-saturated and productive sediments. In this case, at the first stage, there is a gradual reduction of initial gas saturation K_{go} to the value of critical gas saturation $K_{g.crit}$, which corresponds to the maximum content of capillary retained irreducible water in the formation with the appropriate reservoir properties; then there is a sudden displacement of gas by water to the residual gas saturation $K_{g.res}$. The duration of the first stage of displacement depends on the reservoir properties of the water-encroached formations and pressure gradient. When gas pools are developed in depletion drive with a recovery rate of no more than 5% of the initial gas reserves in the pool, in high permeable formations with ≥2m thickness, which lies directly above the current **GWC**, the duration of the first stage is ~0.5 years. For formations with lower reservoir properties, the duration of the first stage increases to ≥ 1 year. In the first stage, gas is displaced from the pay zones by single-phase filtration. The discontinuous nature of gas displacement by water at low-pressure gradients causes a discontinuous rise of **GWC**. The amplitude of **GWC** jumps is determined by the size of the capillary impregnation zone when the gas saturation of the formation decreases to the $K_{g.crit}$ value. At breakthrough displacement of gas with water at pressure gradients ≥~0.001 MPa/м at the first stage, it is possible to reduce the initial gas saturation in the bed, in which the gas content is higher than the value of $K_{g.crit}$. In the second stage, the gas flash is displaced by water until the gas saturation breakthrough - $K_{g.break}$. With the gas content in the bed, water and some gas enter the well from it. In the third stage, the gas content in the water encroachment bed decreases if there is gas cross-flow between beds. The duration of the first stage is less than at large pressure gradients; gas is displaced by water and higher reservoir properties of the formation. At large pressure gradients, the first stage may be virtually non-existent. Breakthrough displacement has not been detected in productive sediments with permeability <~0.1 D; in such sediments, the gas is jammed, and the waterfront bypasses them through more permeable beds. The duration of the third stage of the breakthrough displacement significantly depends on the structure of the pool and the possibility of gas flow to the enclosing beds. If there are no flows in the formation, the breakthrough gas saturation may remain.

In hydrophobic formations, the breakthrough gas saturation by water may exceed $K_{g.break}$~**0.6**. These data were obtained by observing the displacement of gas by water at one of the wells of the Shchelkovsky **UGS** under conditions when special hydrophobization of productive highly porous and highly permeable deposits in one well caused the almost complete displacement of water during gas injection. During gas recovery, this well quickly experienced water encroachment from bottom waters, while the residual gas content in the watered sediments was at the level of ~0.6. Before the hydrophobization of these deposits, their gas content was ~0.7, and practically waterless gas was recovered from these deposits at K_g≥0.5, and after water encroachment, the residual gas content was ~0.2. Furthermore, the well in which hydrophobization was carried out was not used for gas production.

These data show the presence of additional problems during the operation of **UGS**, which are created in depleted gas-condensate pools. In such pools, the most highly permeable deposits are likely to be hydrophobic.

Laboratory studies of gas displacement by water (V. Martos and V. Ryzhik) were found the following:

1. The completeness of gas displacement is a non-monotone function of the displacement rate and properties of porous medium;

2. While maintaining optimal displacement conditions in different porous media, different amounts of gas are jammed. The residual gas saturation limit varies within 0.1÷0.3 of the pore volume;

3. Two areas of dynamic displacement conditions have been identified. In the area of low displacement velocities, capillary front dispersion occurs, which prevents the formation of gas aggregates. At high displacement rates, viscous dispersion occurs, which causes gas jamming in porous medium. Optimal displacement conditions are determined by the ratio of capillary and viscous forces and, accordingly, depend on the reservoir properties of the sediments**.**

The completeness of gas displacement by water during the development of gas pools in the depletion drive is practically determined by the system of producing wells arrangement, as the main volumes of non-recovered gas remain in the **MSB**s where there are no producing wells, which are limited by properties of **LPB1**s.

2.3. Influence of pore surface hydrophobicity on well productivity.

Detailed studies of the effect of productive deposits' wettability on fluid flow have been carried out on quartz capillaries with a radius of ~3÷11 µkm. with a hydrophilic and hydrophobic surface. These studies were carried out under the guidance of Professor N.V. Churaev at the Institute of Physical Chemistry of the USSR Academy of Sciences [25]. Oils of various viscosities with gas bubbles were used as moving fluids. It was found that in capillaries with a hydrophilic surface, the movement of gassy oil occurred without an initial pressure gradient (see Fig. 18 A). In capillaries with a hydrophobic surface, the gassy oil flow was recorded only at pressure gradients above a certain value of the initial pressure gradient (see Fig. 18 B).

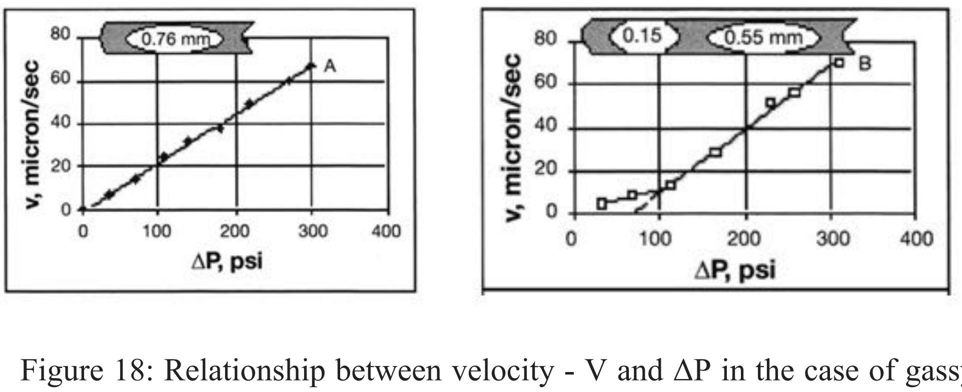


Figure 18: Relationship between velocity - V and ΔP in the case of gassy oil flow through: A- hydrophilic capillaries diameter 10 µm; and B- through hydrophobic capillaries diameter 11 µm. Light oil from the Samotlor field.

It was found that, under identical conditions, the gassy oil flow in hydrophilic capillaries occurs faster than in hydrophobic capillaries (see Fig. 19).

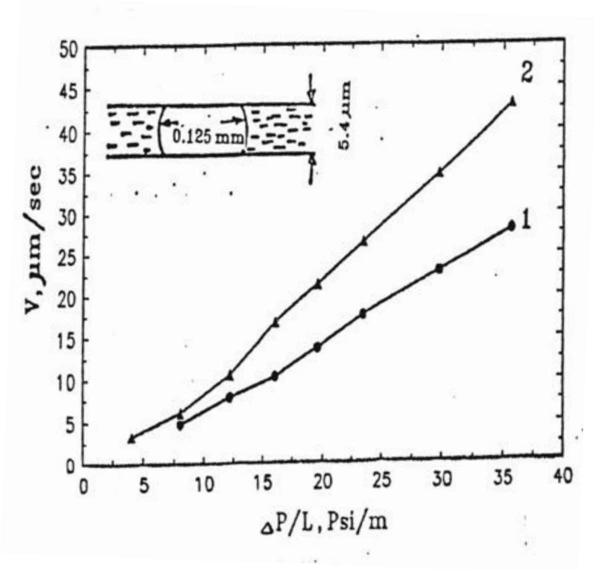


Figure 19: Relationship between V and ΔP/L in the case of gassy oil flow through hydrophilic (2) and hydrophobic capillaries (1) diameter 5.4 μm.

An analysis of the results showed that the value of the initial pressure gradient for the movement of oil with gas bubbles in capillaries with a hydrophobic surface is determined by the hysteresis of the contact wetting angle. The pressure drop - ΔP_o, which is necessary to overcome the initial pressure gradient during oil movement, can be determined from the following equation:

$$\Delta P_o=2(\cos\theta_R - \cos\theta_A)\frac{\sigma}{r} \qquad (6);$$

where ϑ_R is retreating and ϑ_A - advancing wetting angles, r – pore radius, σ – surface tension.

These works were continued by other researchers as applied to the movement of retrograde condensate in quartz capillaries with a radius of ~3÷6 μkm with a hydrophilic and hydrophobic surface. The absence of an initial pressure gradient during the movement of the condensate column in hydrophilic capillaries and the presence of an initial pressure gradient during the movement of the condensate column in hydrophobic capillaries were also recorded. If only part of the capillary surface was hydrophobic, and part remained hydrophilic, the value of ΔP_o increased significantly [64]. Productive deposits in gas-condensate and oil pools are only partially hydrophobic; filtration parameters of such deposits, especially in the near-well zones of producing wells, are significantly lower than under similar conditions with a hydrophilic pore surface. The hydrophilization of the pore surface of productive deposits leads to an increase in well productivity [18].

A comparison of the results of studies of the phenomenon of the initial pressure gradient on hydrophobic quartz capillaries with the data of gas flow on hydrophilic porous media (see above) shows the following. In the compared series of experiments, qualitatively similar results were obtained. The presence of an **IPG** during the gas flow in low permeable porous media and gassy oil in hydrophobic capillaries with an initial pressure gradient is recorded under different conditions:

• Different wettability of the surface of pores and capillaries. In porous media, there was irreducible water; its content and distribution significantly affects both the presence and the features of the manifestation of **IPG**. There was no water in the hydrophobic capillaries;

• Presence of pores of different cross sections in porous media, which are the structure of capillaries of variable radius and shape, which leads to the manifestation of the Jamin effect. Various physicochemical properties of fluids and their distribution in the studied media.

It seems appropriate and practically important that the established phenomenon of the initial pressure gradient during the gassy oil flow in hydrophobic capillaries is considered a fundamentally different phenomenon. The significance of taking this phenomenon into account when developing gas-condensate pools, as well as oil pools. Many oil pools begin to develop in a depletion drive before the use of the project development system in order to accelerate the start of oil production. The depletion drive significantly complicates the subsequent development of such a pool, since gas is released from oil in the zones of formation pressure decrease and, accordingly, gassy oil flows in this part of the pool. The gassy oil flow through hydrophobic pores occurs after overcoming a certain value of the initial pressure gradient. Accordingly, there is a decrease in the productivity of producing wells and a decrease in the completeness of oil recovery, in particular by water flooding. The use of the depletion system worsens the performance of subsequent development systems.

2.4. Some possibilities of changing the wettability of the pore surface of productive deposits.

In **HC** pools, highly permeable deposits contain pores of different cross-sections; some pores remain with the hydrophilic surface, and some pores become hydrophobic. At the contact of pores with different wettability, marked above, the flow of gassy oil and retrograde condensate occurs at pressure gradients greater than certain values of some initial pressure gradient. Accordingly, in pools, the proportion of rocks in which fluid flow occurs during the initial pressure gradient increases, which leads to a decrease in producing well productivity and causes a decrease in the completeness of **HC** recovery. This conclusion is supported by numerous field data [7, 18].

2.4.1. Some possibilities of hydrophilization of productive deposits in gas pools.

We started work on hydrophilization of productive deposits in the late 60s of the last century [11]. The hydrophilization method was first tested in the producing wells of the Gazli and Dzharkak fields (both pools are composed of terrigenous rocks), and the Northern Mubarek pool is composed of carbonate rocks. The initial condensate content in these pools is ~20g/m^3 of gas; methanol was used as a solvent. In all cases, there was an increase in the condensate content in the produced gas and a slight increase in the gas productivity of the treated wells. This shows that even with a low condensate content, partial hydrophobization of the pore surface occurs. Subsequent work was carried out in the development of gas-condensate pools in the offshore fields of Azerbaijan. Table 3 shows the first results of applying this method.

Table 3: Some results of the use of the hydrophilization method.

Well - ID	Year of treatment	Gas flow 1000 m3/day before/ after treatment	Condensate flow t/day before/ after treatment	Condensate density kg/m3 before/ after treatment
300	1983	105 / 145	0.04 / 0.8	737 / 770
561	1984	350 / 450	6 / 13	745 / 760

562	1984	320 / 370	18 / 27	770 / 785
525	1985	550 / 600	23 / 30	745 / 782
525*	1986	350 / 400	22 / 28	- / -
560	1985	585 / 631	34 / 53	765 / 773
560*	1985	220 / 250	19 / 25	756 / 765
34	1985	280 / 380	20 / 32	745 / 779
34*	1986	330 / 350	13 / 19	- / -
107	1985	100 / 120	9 / 14	770 / 778
70	1985	330 / 345	33 / 49	772 / 794
57	1986	150 / 160	6 / 8	774 / 790

*/ Repeated treatment.

From the data follows:

1. An increase in condensate outflow by an average of **50%** (without data from well No. 300);
2. An increase in the density of the recovered condensate from an average of **758** kg/m^3 to **778** kg/m^3;
3. An increase in gas production under the same recovery regime by **20%**.

The processing time was 3 days. Stable production from treated wells was ~0.5 years. The chemical composition of stable condensate, which was obtained before and after hydrophilization of one of the typical wells, was studied by gas-liquid chromatography; the research results showed a decrease in the proportion of light **HC** fractions (C_{10}÷C_{12}), an increase in the proportion of heavier **HC** fractions (C_{13}÷C_{17}) and the presence of **HC** fractions (C_{18} ÷C_{24}). Full results of analyses are given in [18].

The use of the method of hydrophilization of productive deposits in the near-well zones of producing wells makes it possible partially to wash off the adsorbed and adhered heavy fractions of retrograde condensate from the pore surface and recover heavier **HC** fractions. The largest increase in the content of heavy **HC** fractions and an increase in productivity occur when productive deposits with high reservoir properties are discovered in the well. The given data were obtained using methanol, which was displaced by a solution of salts of low salinity. The duration of maintaining the beneficial effect of hydrophilization is determined by the properties of the surfactant. It is advisable to use specially selected surface-active agents and solvents, which should be selected based on the results of laboratory work, taking into account the chemical composition of the retrograde condensate and oil, if the pool contains residual oil, and the reservoir properties of the main productive deposits.

The hydrophilization procedure is given in [17, 18]. We note the following. The washing of the pore surface must be carried out in the capillary imbibition drive or by creating a solvent bath. **Solvent injection at large pressure gradients is practically useless,** since deep breakthroughs of the solvent mainly occur through the channels with the greatest permeability, and the solvent practically does not wash the surface of the most hydrophobic pores. It is advisable to displace the solvent with the solution with a surfactant at low-pressure gradients, while the volume of the solution should be sufficient to displace all fluids within the treated zone. The need to use such a regime for washing the surface of hydrophobic rock pores is confirmed by the practice of using the method. These processes are especially significant in the development of oil pools.

The possibility of changing the wettability of productive deposits in gas-condensate fields by chemical treatment has been studied by many specialists; the results of practical use are analyzed in [60] and note that the processing of productive deposits was carried out within a radius of 5 m from the wellbore. The practical use of chemical treatment is given, in particular, in the works of [53].

2.4.2. Chemical methods to increase the completeness of oil recovery after the application of water flooding.

Water flooding remains the main method in the development of pools with conventional oil. The use of chemical methods allows increased completeness of oil recovery. Chemical methods modify different properties of fluids in rocks to mobilize the remaining oil. The Alkaline/Surfactant/Polymer Flood method - **ASP** Flood is the most widely used method for increasing oil recovery after water flooding. This method was developed in the 80s in Shell Netherlands. The results of the worldwide method implemented between 1987 and 2011 showed that the increase in oil recovery could vary between 5% and 28% [45]. This showed the high promise of **ASP** Flood and stimulated an increase in field and laboratory work, while much attention was paid to the selection of cheaper reagents. The work carried out substantiated the possibility of using a number of cheaper reagents that provide a high degree of oil displacement [3, 27, 65]. These results were obtained on single rock samples, so they justify the high promise of **ASP** Flood, but do not allow justifying the most effective use of this method in field conditions. The field studies of **ASP** flooding have shown that the effectiveness of using this technology depends on the choice of reagents for almost every pool.

The most detailed studies of the technology were carried out at the Daqing Oil Field, the largest oil field in China [2, 28, 34]. This field was discovered in 1959 and put into production in 1960. The main productive deposits of the field contain light oil and gas in highly porous sandstones with a permeability of >100 md. The field was developed, in the first stage, probably in depletion drive, and then using water flooding. Such a development system and, probably, insufficient knowledge of the internal structure of the pool led to the achievement of the maximum rate of oil recovery only in 1994. From 1976 to 2002, the field maintained its plateau of oil and condensate 1 million barrels/day and produced a cumulative total of 13 billion barrels. The large-scale work on the use of **ASP** flooding began in 2014 at the stage of declining oil production. During the work, various reagents were tested, the choice of which was carried out taking into account the properties of residual oil. This established the following:

1. The type of alkali affects the effect of **ASP** flooding. The choice of reagents should be carried out taking into account the properties of residual oil;

2. Due to the low acid number of crude oil, asphaltene and resin components in oil determine the reduction in the surface tension value in the oil-water system; asphaltenes are likely to have a greater influence, elucidation of this requires additional work;

3. Further work is needed to study the effect of emulsification in **ASP** flooding;

4. **ASP** flooding made it possible to increase the oil recovery efficiency by **30%** at a cost of <$30 per barrel. The oil recovery efficiency is close to the maximum, which was obtained during field and laboratory studies of the method.

The subsequent analysis of the results of using **ASP** flooding at the Daqing Oil Field showed that the effectiveness of using this method also significantly depends on the following factors [28]:

1. Large-scale heterogeneity of the field, which is due to the presence of a highly permeable channel in it that separates the upper and lower parts of the pool. The predominant displacement of residual oil took place from the lower high-permeable deposits. The remaining oil is predominantly in the upper sediments and at the channel edge of the channel.

2. Traditional studies of the internal heterogeneity of the field do not accurately characterize the distribution of the remaining oil.

3. Scheme of location of injection and production wells.

4. About **40% of OOIP** remains after **ASP** flooding in the field. The remaining oil reserves have a high development potential. Methods for improving the efficiency of oil recovery must take into account the large-scale heterogeneity of the field.

Large-scale use of alkaline flooding was carried out on one of the heavy oil pools in the Shengli Oilfield in China [74]. Reservoir parameters are as follows: depth 4260 ft, temperature 131°F; productive deposits are sandstones with average porosity 0.26 and permeability 560 md, initial oil saturation 0.57; oil parameters: gravity (0API) 20.6, kinematic viscosity 325 cSt. As a result of the work carried out, ~32% oil recovery was achieved. Laboratory and field studies were carried out on the effect of the concentration of injected alkali and various additives to it, the use of water with low salinity, as well as hybrid injection modes. It was found that the modernized injection of alkaline solutions has a significant impact on no thermal flooding.

The possibility of changing the mixed wettability of productive deposits to hydrophilic in heavy oil pools, which are contained in carbonate deposits, is noted in the works [21, 69].

The above data show that the development of conventional light and heavy oil pools can provide high oil recovery efficiency, up to about 0.6, from highly permeable productive deposits in light oil pools. It is likely that the completeness of oil recovery from such pools can be higher if, when designing the development system, results of studying the features of the internal structure fluid flow in **HC** pools and oil properties in sediments with different reservoir properties, are taken into account, which will significantly reduce the cost of oil production.

Past 3. Some ways to increase the completeness of hydrocarbon recovery.

The experience of developing numerous oil and gas pools shows that the completeness of oil and gas recovery from pools in sedimentary rocks is largely determined by taking into account the complex influence of the following factors:

・Features of the internal structure of pools and the fluid flow in them, as well as the deformation of unconsolidated rocks in low-permeable barriers and sub-vertical channels with a decrease in formation pressure in the pool. This deformation causes an increase in the initial pressure gradient during the fluid flow through **LPB**s and **SVC**s and, accordingly, an increase in the filtration resistance of the pool.

・Features of the interaction of hydrocarbons with the surface of the pores of productive deposits with different reservoir properties that cause differences in the properties of produced and residual oil when using different development systems.

・The flow of gassy oil and condensate in hydrophobic pores only at pressure gradients above a value of some initial pressure gradient.

・Reliability of assessment of hydrocarbon reserves and, first of all, oil. Reserve estimates using average estimated parameters are not very representative, especially when estimating recoverable oil reserves. It is necessary to take into account the probable completeness of oil recovery from each type of productive deposit with the planned development system.

3.1. The additions to the used system of exploration and development of oil and gas pools.

To take into account these factors, it is advisable:

1. When choosing the location of the prospecting hole, supplement the complex exploration works by including aero-space observations in it to study the modern tectonics of the area.

2. Detailed elaboration of modern tectonics of the area of the trap of the identified **HC** field and the study of its tectonophysics features before the start of exploration drilling based on the results of geological and geophysical methods, including 3D seismic, as well as aero-space observations. The use of results of ground or aerial-geochemical studies can help to identify abnormal contents of helium, methane, etc. Such a complex of studies makes it possible to identify a part of **LPB**s and **SVC**s, to which the main fracture zones are confined.

3. To concentrate the exploration of the identified field on the estimation of HC reserves within the whole field.

4. To estimate in more detail the reserves in the pool, which is planned to be the first to be put into development. Initial data for the design of the pool development systems can be obtained within the **BFM** (see Fig. 7) that will optimize the location of development wells in the **MSB**, which is planned to be the first to be put into development. To estimate the reservoir properties of productive deposits and the properties of formation fluids in the sediments, which determine the HC reserves in the first **MSB**. It is necessary to study the oil properties based on the results of hydrodynamic tests of wells and in cores from different parts of the pool in productive deposits with similar reservoir properties.

5. The development project focuses on the use of **independent** systems for **HC** recovery from each **MSB** of significant **HC** reserves. At the first stage of development, use the system of development of the first **MSB**, which, taking into account local and regional geological information, is the most appropriate for the developed pool and allows for an economically justified rate of **HC** production.

6. To drill all development wells in the **MSBs** in zones that are remote, at least **0.5** km away from tectonic faults, regardless of their depth, and in which neo-tectonic faults have not been recorded. It will reduce the likelihood of rapid breakthrough of injected fluids into producing wells through **SVC**s and selective displacement of oil and gas-condensate from the pool in the time of formation pressure maintenance, as well as water encroachment-producing wells by bottom waters. Permanent, detailed control by field methods of the production process in the block being developed and in neighboring

blocks. Observations of formation pressure dynamics are most effective in the development of gas pools (see Application 1).

7. In the process of developing the first **MSB**, test of **EOR** methods. To design **EOR** methods for every **MSB** with significant **HC** reserves.

8. Within the developed field, prepare additional areas for development in which it is more accurate to estimate the probable recoverable hydrocarbon reserves. If necessary, use additional drilling and studying wells, in order to also localize the **LPB**s and **SVC**s.

9. If a transition to another development system is planned, it is necessary to evaluate the impact of the previously used system development on the properties of oil and its distribution in those types according to the reservoir properties of productive deposits, which contain the bulk of residual oil reserves.

Below are the features of the development of oil and gas pools, taking into account the above.

3.2.1. Development of "dry" gas pools.

The experience of the development of more than 50 gas pools showed the following:

1. The completeness of "dry" gas recovery when using the depletion drive substantially depends on taking into account in the project of the pool development the location and properties of **LPB1s** and **SVCs.** At the beginning of the development of pools, the drainable volume - V_{dr} is <70% of the actual pool gas-saturated volume. With an increase in the number of producing wells, there is an increase in the drained volume of the pool. It is impossible to be involved in the development of all the gas reserves in the pool. When the value of the **GRF**≥~0.3, V_{dri} values decrease due to an increase in **IPG** values in **LPB1**s. The increase in **IPG** values is especially significant in pools with high initial formation pressure values. The increase in the completeness of gas recovery requires the input of additional producing wells in stagnant zones that contain significant gas reserves.

2. The edge and bottom water intrusions into development pools take place selectively and spasmodically**,** predominantly locally, through **SVCs**.

3. In order to increase the gas recovery completeness, it is advisable:

- To preserve pool energy, commercial gas production with an annual withdrawal of ≥3% of the gas reserves in the pool should be started simultaneously in the **MSB**s where the main gas reserves are concentrated.
- Place producing wells to reduce the likelihood of stagnant zone formation. Have the maximum number of necessary producing wells in those pool parts, where there is no bottom water, regardless of the oil fringe presence.
- At the initial stage of pool development to organize the system of production, which will allow, based on the results of field observations, with the withdrawal of no more than ~10% of the initial gas reserves in the pool, to establish the presence of gas cross-flows between different blocks and values of **IPG**s of gas flow during main **LPB**s. It is necessary to estimate formation pressure dynamics in all suitable wells in order to evaluate the filtration properties of **LPB**s, current pool drainable volume and current residual gas reserves (see Appendix 1).

• In all producing and observation wells, make background measurements of neutron logging (**NL**) about a minimum of a month after the well cementing. When water appears in the production of each well, it is necessary to carry out a repeated **NL** to localize water encroachment of beds.

3.2.2. The development of gas-condensate pools.

The development of gas-condensate pools is the main problem caused by the precipitation of retrograde condensate. In the depletion drive, completeness of condensate recovery from the pools with high specific condensate content ≥~200 g/m^3 gas is in order of 0.3÷0.5 of its initial content in the recovered gas.

At pool development, use a cycling process or water injection for pressure maintenance. As a result, the earliest injection gas breakthroughs or water encroachments occur in the producing wells; large stagnant zones are saved; the pool's filtration resistance increases in jumps with the formation pressure drop. Failure to take into account the presence of **LPB**s and **SVC**s in the pools determines the low efficiency of using these methods in the development of many pools and, in particular, in the development of the Novo-Troitskoye field in Ukraine**.** In general, the project was unprofitable [70]. Effective use of the cycling process requires localized **SVC**s within **MSB**s. When identifying such **MSB**s, it is necessary to determine the values of **IPG** in the **LPB**s between these blocks in order to justify the pressure gradients during dry gas injection. The position of the injection wells should be selected, taking into account the values of **IPG** on the barriers between the blocks, the position of the **SVC**s and the distance of the producing wells from the **SVC**s. Before carrying out the cycling process, it is necessary to pre-develop the pool in the depletion drive. The results of observations of the formation pressure dynamics in different blocks with the recovery of ~10% of the initial gas reserves in the pool, in combination with 3D seismic data and aero-space observations, make it possible to localize the position of most **LPB**s and **SVC**s in the pool.

The loss of condensate can be significantly reduced if the use of directional intra-contour water flooding is suitable in passive production **MSB**s that are separated by **LPBs** from gas production activity zones (see Fig. 20).

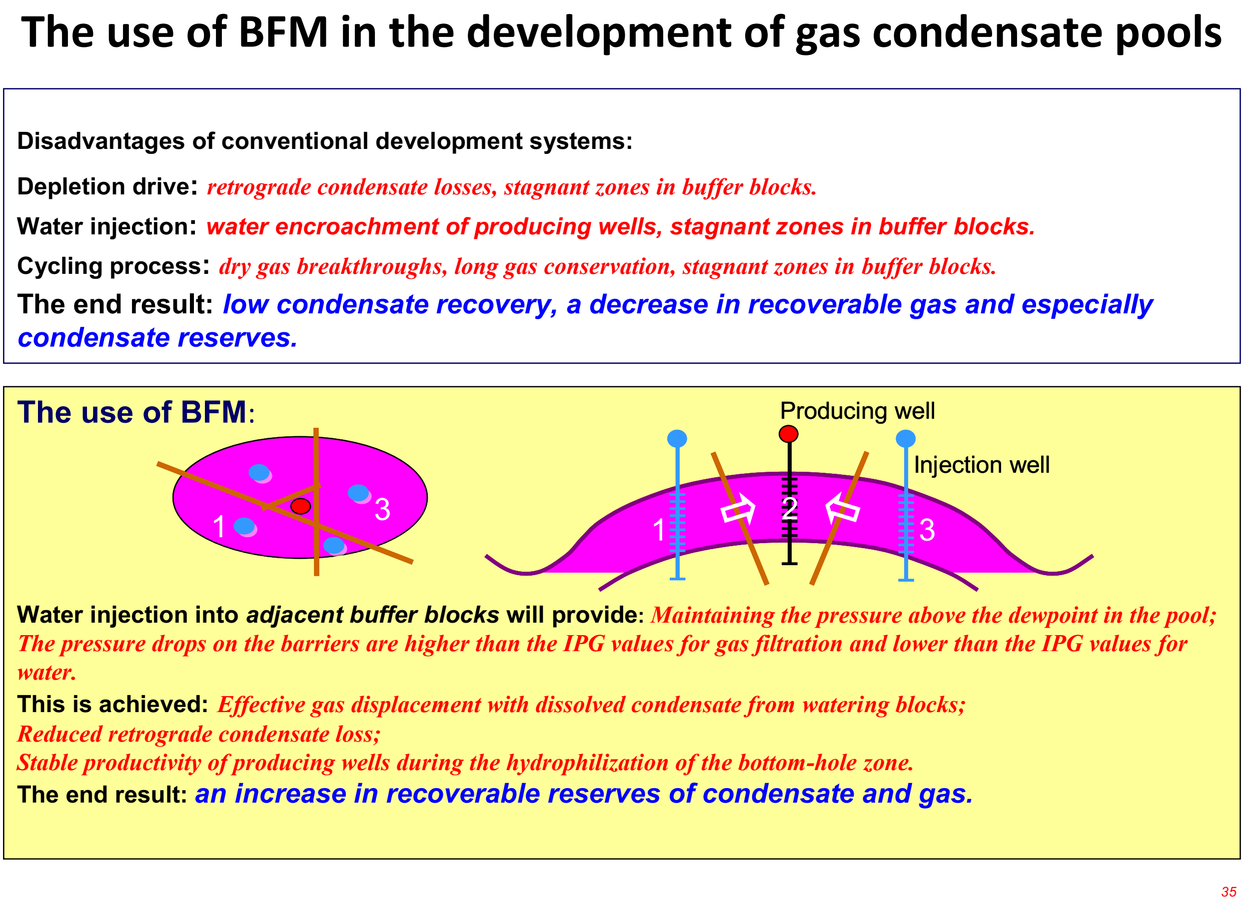


Figure 20: Scheme of **BFM** application for the development of gas-condensate pools by directional intra-contour water flooding.

Such water injection can be carried out from the beginning of the pool operation or during the implementation of other development systems, if the formation pressure is maintained above the bubble-point pressure for condensate in this pool. This system is most effective if a significant part of the gas and condensate reserves can be recovered when the pool has water-flood performance. The gas and condensate recovery from the water-flooded parts of the pool can be carried out by a constant number of producing wells, whose production rates can remain practically unchanged throughout the entire water injection period into the pool [16, 18]. The water-flooding into the pools, in which the active intrusions of bottom or edge waters take place, will allow slowing the water intrusions. To maintain the productivity of production wells and increase the completeness of condensate recovery, periodic hydrophilization of near-wellbore zones of producing wells is necessary. The frequency of hydrophilization should be set, taking into account the composition of the condensate, the thermobaric conditions in the pool and the properties of the reagents used for hydrophilization**.** When using such a system, there is no need to localize **SVC**s, both within the water-flooded blocks and in the zones of producing wells. Water injection through **LPB1**s can occur at pressure gradients within <~10 MP/m; in this case, water will not enter the **MSB** from which gas with dissolved condensate is taken off due to the large difference in the **IPG** values for the movement of gas and water through the barrier.

The pool development, which takes place *in* large productive thickness, a part of wells can be used for water injection under **LPB2**s and simultaneously for gas recovery from deposits above the barriers. This water injection has been successfully tried at the Dzharkak field. Water was pumped into the roof wells, the injected water breakthroughs in the producing wells were not observed**,** and the pool development technological parameters corresponded to the calculated ones [18].

3.3. Some opportunities to increase the completeness of oil recovery.

This section discusses some of the possibilities for increasing the completeness of light oil recovery by taking into account the identified natural phenomena. We discuss only the problem, since we have not studied the properties of residual heavy oil using various recovery systems.

When developing pools of light oil, the situation is considerably more complicated than gas pool development, since the internal heterogeneity of the entire oil reservoir and each **MSB** determines the presence of potentially recoverable different type of oil and their different interaction with deposits with different reservoir properties. Many oil pools begin to develop in a depletion drive before the use of the project development system in order to accelerate the start of oil production. The depletion drive significantly complicates the subsequent development of such a pool, since gas is released from oil in the zones of formation pressure decreases and, accordingly, gassy oil moves in this part of the pool. The movement of gassy oil through hydrophobic pores occurs only after overcoming a certain value of **IPG** [25]. The use of the depletion system worsens the performance of subsequent development systems, since it causes a decrease in the productivity of producing wells and the completeness of oil displacement, in particular by water flooding.

In the oil pool development using water flood systems, or injection of other displacement fluids, in this case, the object of production planning is the entire conventional pool**.** However, due to the lack of information on the probable position of the **LPB**s and **SVC**s, selective oil displacement by injected fluids takes place (see Fig. 21).

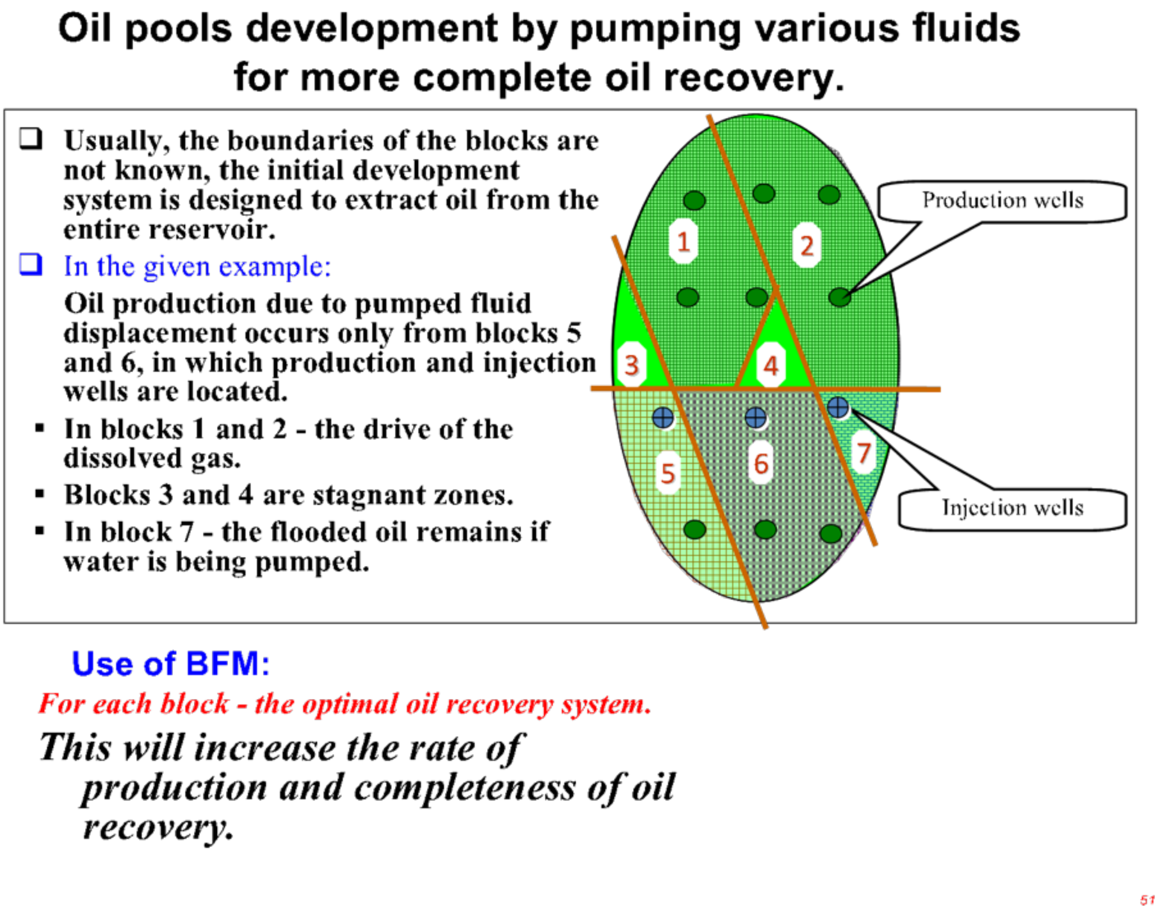


Figure 21: The scheme of use of **BFM** in the development of oil pools by pumping different fluids for more complete oil recovery.

This is confirmed by the experience of developing many oil pools, where the compaction of the well spacing pattern and the drilling of drain branch holes allowed the recovery of significant amounts of oil [41, 67]. If there is information on the Multi-scale block structure of the pool, it is advisable to use the optimal oil recovery systems for each main **MSB**. To increase the completeness of oil recovery, it is expedient to provide pumping of working fluids and, in particular, water, at low-pressure gradients. Development experience in the Prudhoe Bay and the Daqing fields shows that the completeness of oil recovery -**ORF** at the level of 0.6 is practically achievable using **EOR** methods and after water flooding. This shows that large values of **ORF** are also achievable, given the features of the internal structure of pools and the fluid flow in them, as well as the reservoir properties of productive deposits and the properties of residual oil in different productive deposits, which contain the main unrecovered oil reserves. This will allow choosing the optimal number and location of development wells in each **MSB**, increase the use of **EOR** methods, and reduce oil production costs.

3.3.1. Gas-oil and oil-gas pool development.

In the process of oil production from pools with a small gas cap without maintaining formation pressure or with a small amount of water injection, the equilibrium on contacts gas-oil-**GOC**s is disturbed. The gas begins to flow in the drainage zones. This leads to a decrease in formation pressure almost within the entire gas cap. In passive blocks, from which there is no oil recovery, the formation pressure in the oil part of the pool practically does not change due to the small effect of oil recovery from active blocks. Oil in passive blocks flows into the gas cap mainly through **SVCs,** especially while maintaining pressure in the oil part of the pool. Most of the oil converts into residual oil, and its recovery becomes problematic. Some formation pressure is maintained in the gas part of the pool, which intensifies the gas flow into the oil recovery zones. The result: completeness of oil reserves recovery is low. It follows, in particular, from the results of the development of the oil-gas pool Karadag [18]. With a large gas volume in the gas-oil or oil-gas pool, it is usually predicted that the completeness of oil recovery will be about 10%. Many such pools are in conservation, even within the fields on which some oil pools are being developed. If information is available about the Multi-scale block structure of the pool, it is advisable to use the different development systems, taking into account the ratio of the oil and gas volumes in each **MSB**. With a small amount of the gas cap in **MSB**, it is expedient, in particular, to use a barrier water flooding [67]. The water flooding block prevents gas advancement in producing oil wells and reduces the likelihood of oil flows into the gas cap in passive blocks. The use of different development systems in different **MSB**s may increase the completeness of oil recovery from the pool and provide the possibility of simultaneous production of oil and a low rate of gas production (Fig. 22).

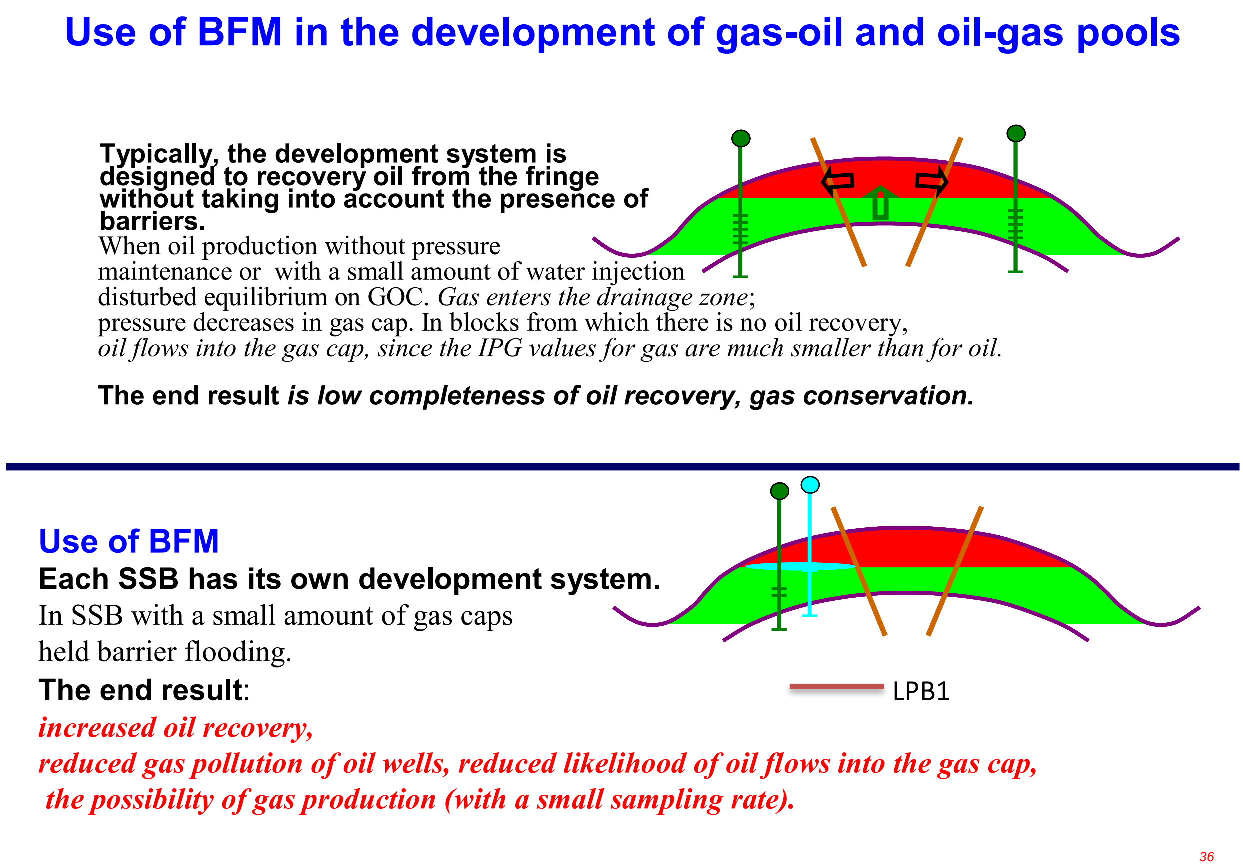


Figure 22: The scheme of use of **BFM** in the development of gas-oil and oil-gas pools.

When implementing various gas-oil or oil-gas pool development systems, it is necessary to take into account the above features of hydrophobization of the pore surface and the presence of an initial pressure gradient in hydrophobic pores during the movement of gassy oil.

Conclusions.

1. Natural, industrially significant accumulations of oil and gas are hydrocarbons -**HC** pools; their internal filtration structure, in the first approximation, is a set of blocks of different scales –**MSB**s. **MSB**s are separated by neo-tectonic - **LPB1**s and lithological barriers – **LPB2**s, as well as contain thin, extended sub-vertical channels – **SVC**s (see Fig.7). Sub-vertical channels are formed mainly in zones of destruction during neo-tectonic movements before and after migration of the **HC** into the trap. The channels in compression zones turn into low-permeable barriers – **LPB1**s; in extension zones, some **SVC**s remain in the form of fractures of various openings. Low-permeable rocks, which are traced between by neo-tectonic barriers, are lithological barriers within **HC** pools - **LPB2**s; they differ from **LPB1**s. **LPB2**s are oriented almost parallel to the stratification of the main productive deposits in the pool and are composed of compacted rocks. The fluid flow through barriers occurs only at pressure gradients above a certain value of the initial pressure gradient - **IPG**. The values of **IPG** during the gas flow through a single barrier in gas pools are usually no more than a few MPA/m; the value of **IPG** during oil or water flow under the same conditions exceeds several tens of MPA/m. In oil pools, each multi-scale block is a separate reservoir. The internal filtration structure of majority pools differs from that adopted in the standard filtration model, which postulates the hydrodynamic connectivity of the reservoir and the possibility of describing the fluid flow in terms of Darcy's law.

2. The properties of sub-vertical channels and neo-tectonic barriers depend on the properties of the rocks in the destruction zone and the conditions of their occurrence at different geological times, including subsequent deformations. The value of **IPG** in barriers is determined by the properties of the rocks that compose them, the properties of the fluids in them and fluid flowing through them, and the stress state of the barriers. Part of **SVC**s and **LPB1**s contains country unconsolidated low-permeable rocks. When formation pressure decreases in a developed pool, unconsolidated low-permeable rocks become more compacted, which leads to the transformation of some **SVC**s into new **LPB1**s and an increase in **IPG** values at fluid flow in pre-existing **LPB1**s. If there is a further increase in formation pressure in this pool, the deformation of unconsolidated rocks persists, which is clearly manifested when creating underground gas storages in depleted pools. In a developed pool, especially a gas pool, an increase in **IPG** value in the barriers leads to an increase in the filtration resistance of the pool and the formation of additional stagnant zones.

3. Localization of the destruction zones, sub-vertical channels and neo-tectonic barriers within them, can be carried out using aero-space observations, 3D seismic data and hydrodynamic studies.

4. Interaction of oil and condensate with porous media causes: mixed wettability of major productive deposits, differences in the properties of produced oil, and condensate from rocks with different reservoir properties. When oil is displaced by water, the properties of the residual oil differ from the properties of the produced oil and are significantly different in sediments with different reservoir properties. The content and composition of the residual oil varies significantly in the rocks, which seem similar in integral characteristics and reservoir properties (m, K, S_{wi}). The completeness of oil recovery during water flooding depends on the reservoir properties and wettability of productive deposits, as well as on the magnitude of pressure gradients during water injection.

5. The mixed wettability of the main productive deposits causes a decrease in the productivity of oil and gas condensate-producing wells. This is due to the presence of an initial pressure gradient during the gassy oil and gassy condensate flow in hydrophobic porous media. The possibility of

hydrophilization of the pore surface of productive deposits in the near-wellbore zones of producing gas-condensate wells has been proved. This makes it possible to restore well productivity and ensure the production of condensate, which also contains heavy hydrocarbons that were not previously recovered. The effective application of the hydrophilized method requires the selection of a solvent and, most importantly, surfactants that will ensure long-term stable operation of producing wells, taking into account the properties of productive deposits, which contain the main gas reserves in a particular pool.

6. To increase the completeness of oil and gas recovery, it is advisable when exploring and developing oil and gas pools, as well as when using **EOR** methods, expedient:

A. Take into account:

・Revealed natural features of the internal structure of pools and the fluid flow in them;

・Features of the interaction of oil and condensate with porous media, which cause differences in the properties of produced oil and condensate from rocks with different reservoir properties, as well as a decrease in well productivity due to the presence of an initial pressure gradient during the flow of gassy oil and gassy condensate in productive deposits with mixed wettability;

・Differences in the properties and distribution of various components of residual oil in productive deposits with different reservoir properties during water flooding.

B. Conduct, in particular, the following additional studies:

・The influence of the value of pressure gradients on the efficiency of oil and gas displacement by water, as well as other working fluids from productive deposits with high reservoir properties, when using various methods to increase the completeness of **HC** recovery from productive deposits with mixed wettability and different reservoir properties.

・To improve methods of localization for sub-vertical channels and neo-tectonic barriers.

7. Accounting for the above can allow:

・In terrigenous deposits of conventional and unconventional pools, enhance the completeness of oil and gas recovery minimum by **10-15%** of the initial pool reserves, and practically double the recovery of condensate reserves from pools, the development of which is expedient using a pressure maintenance system;

・Increase the reliability of estimates of residual recoverable **HC** reserves;

・Increase the efficiency and scope of the use of **EOR** methods;

・Effectively put into production parts of oil-gas and gas-oil pools that were not developed due to a low forecast for oil and gas recovery;

・Reduce the likelihood of water encroachment producing wells and the damage of high **HC** losses, especially during the development of gas-oil, as well as **HC** pools on the shelf and in unconventional pools;

- Speed up the process of pool development and reduce the cost of developing **HC** fields.

Appendix 1

The influence of sub-vertical channels and low-permeable barriers on the development of pools and their formation and destruction

The appendixes are included in the full version of the article (the PDF is located in the supplementary data section of the online page)

Appendix 2

Results of studying the internal structure of the Lovinskoye oil field using a set of field, remote and laboratory methods

The appendixes are included in the full version of the article (the PDF is located in the supplementary data section of the online page)

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Nomenclature

A - Seepage resistance (MPa^2/m^3);

EOR - Enhanced Oil Recovery

Gg - initial pressure gradient (MPa/m);

h -thickness of strata or sub-vertical channel (m);

h_{ef} - the effective thicknesses (pay thickness, m);

K -permeability (D or md);

K_g - coefficient of gas-saturation (dimensionless);

LPB1s – low-permeable barriers of type 1;

LPB2s – low-permeable barriers of type 2;

m –porosity (dimensionless);

P -pressure (MPa);

ΔP – pressure drop in lab experiments (MPa);

p_{ef} – effective overburden pressure, it is equal to the difference between overburden pressure and formation pressure of fluids in the pool;

$\check{R}$ – well productivity (m^3/day);

S_o - coefficient of oil-saturation (dimensionless);

S_{or} - coefficient of residual oil-saturation (dimensionless);

SVCs - sub-vertical channels;

S_w - water saturation (dimensionless);

S_{wi} - irreducible water saturation (dimensionless);

T2 - transverse delocalization time (MS);

Z - coefficient of compressibility in the gas equation of state (dimensionless);

μ – gas viscosity (Pa.s);

θ_A and θ_R - advancing and retreating wetting angles (◦);

σ – surface tension (millinewtons/m).

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