Possibility of increasing the completeness of oil and gas recovery by taking into account natural phenomena in reservoirs.

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Abstract.

The low completeness of oil and gas recovery when using modern development systems is due to the fact that all development systems are based on the following postulates [1]:

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

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

4. Productive deposits in conventional oil and gas reservoirs are mainly hydrophilic.

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

Development experience and the results of special studies have shown that these postulates are erroneous. In practice, after establishing the absence of hydrodynamic connection within the entire reservoir, the first priority is to compact well spacing of development wells. In oil reservoirs, additional development wells are drilled predominantly evenly over the reservoir area, that is, almost blindly, without taking into account the large-scale heterogeneity of the reservoirs. In gas reservoirs, additional producing wells are drilled in stagnant zones, which are characterized by increased current formation pressures relative to gas recovery zones.

As a result of field and laboratory work, we have identified natural phenomena that determine the fallacy of the above postulates, and it has been practically proven that the internal structure of reservoirs can be identified during their exploration and clarified during development. At the same time, a greater completeness of hydrocarbon recovery and a reduction in the costs of their production are achieved.

Keywords: Completeness of **HC** recovery; Initial pressure gradient; Fractionation of oil and condensate; Reliability of estimates of **HC** reserves.

Accumulations of oil and gas are confined to natural traps, which are characterized by a complex internal structure, the fluid flow in which cannot be described within the framework of Darcy's law. When hydrocarbons penetrate into permeable sediments, heavy hydrocarbon fractions interact with porous media. The exploration and development systems used do not take these natural phenomena into account. Each industrially significant hydrocarbon accumulation, in which tectonic dislocations have not been identified, is considered as a reservoir with a connected hydrodynamic system. This approach is simplified and causes a low completeness of oil and gas recovery, since it does not take into account the features of the internal structure of reservoirs, which determine the fluid flow in them, as well as the features of the interaction of hydrocarbons with various productive sediments.

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The conducted research made it possible to identify the following natural phenomena in oil and gas reservoirs, taking into account which can significantly increase the completeness of oil and gas recovery, accelerate the development of reservoirs, as well as increase the reliability of the assessment of their reserves and reduce development costs [2].

1. Reservoirs are the complex of Multi-scale blocks – **MSB**s, which were formed as a result of tectonic and neo-tectonic movements. Within the reservoirs there are sub-vertical channels – **SVC**s, impermeable and low-permeable barriers – **LPB**s. The fluid flow through **LPB**s occurs only at pressure gradients above the value of a certain initial pressure gradient - **IPG**. The presence of impermeable barriers and **LPB**s in reservoirs causes reservoir compartmentalization. **SVC**s in some parts of the reservoirs have abnormally high permeability. When developing oil and gas condensate reservoirs while maintaining formation pressure, most part of the injected fluids move through **SVC**s and only a portion of these fluids displace oil or gas from the productive sediments. When formation pressure in gas and oil reservoirs decreases according to **SVC**s, production wells are water encroachment with bottom water. **SVC**s, impermeable barriers and **LPB**s are formed mainly in **destruction zones** of neo-tectonic dislocations. Localization of the destruction zones can be carried out using complex aero-space observations, 3D seismic data and hydrodynamic studies.

2. The **IPG** values for fluid flow through **LPBs** and permeability of **SVC**s are determined by: the petro-physical properties of composing rocks; physicochemical properties of the fluids that are contained in them and move through them; the changes in the stress state. The values of **IPG** for gas flow through a single **LPB** in gas reservoirs are in most cases 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 reservoirs, each MSB, limited by impermeable barriers or LPBs, is a separate reservoir**. In gas reservoirs, gas is recovered from **MSB**s, which, at least on one side, are separated from the gas production zone by a **LPB**. The gas flow from the **MSB** into the production zone begins at pressure gradients greater than the **IPG** value for gas flow in the corresponding **LPB**.

3. With a decrease in formation pressure in the developed reservoir, unconsolidated rocks, mainly clayey ones, become compacted in **LPB**s and **SVC**s, which causes an increase in **IPG** values, the emergence of new **LPB**s and a decrease in the filtration properties of **SVC**s. This phenomenon causes an increase in the filtration resistance of the reservoir.

4. Fractionation of oil and retrograde condensate occurs differently in productive sediments with different productive properties. This cause:

- Large pores become hydrophobic;
- Oil and condensate with different physicochemical properties are produced from different wells within the same reservoir, depending on the reservoir properties of the exposed productive deposits;
- Differences in the physicochemical properties of residual oil in productive sediments with different productive properties, in particular when oil is displaced by water.

5. In hydrophobic pores, the flow of gassy oil and condensate occurs only at pressure gradients that exceed a certain critical value. This causes a significant decrease in the productivity of producing wells in oil and gas-condensate reservoirs [3].

Evidence of the presence of these natural phenomena in oil and gas reservoirs, as well as the possibility of taking them into account during development, is given in [2]. If you have any questions or comments, please contact Lev Berman at lsberman@bezeqint.net

Based on the identified natural phenomena in oil and gas reservoirs, it is proposed for practical use:

1. Additions to the complex of geological exploration works and to the methodology for estimating oil and gas reserves by the volumetric method.

2. Additions to increase the efficiency of oil and gas reservoir development systems. The following is recommended:

- Design a development system for each **MSB** with industrially significant hydrocarbon reserves;

- Locate development wells taking into account the likely position of barriers and sub-vertical channels;

- When developing the first **MSB** in oil reservoirs, it is advisable to provide for testing promising methods for increasing oil recovery.

3. The block filtration model - **BFM** of the gas reservoir was justified and developed, which takes into account identified natural phenomena in and the fluid flow in it. Within the framework of this model, it is possible to estimate drainable gas reserves and the maximum value of recoverable residual gas reserves for the development system used. The model was tested during the development of gas reservoirs, which allowed us to obtain positive results. The rationale for **BFM** and some results of its application are given in the appendix.

Taking into account identified natural phenomena in oil and gas reservoirs makes it possible to increase the information content of geological exploration results for assessing hydrocarbon reserves using the volumetric method and for designing reservoir development systems. This allows:

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

- Reducing the likelihood of water encroachment of producing wells with injected and bottom waters through **SVC**s;

- Increase the reliability of estimates of residual recoverable hydrocarbon reserves;

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

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

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

- Reduce the likelihood of large irreversible losses of hydrocarbons, especially during development of gas-oil, as well as hydrocarbon reservoirs on the shelf and in unconventional reservoirs.

Appendix

Block filtration model for the development of gas reservoirs.

The pressure-drop method of estimating gas reserves is widely used in gas reservoir development; but the method does not allow obtaining representative estimates of reserves in the reservoir with Multi-scale block structure. This is due to the lack of information about the boundaries of stagnant zones and P_{fi} in these zones; accordingly, the average current formation pressure in such a pool cannot be reliably determined [2, 4]. Almost the same situation occurs when developing unconventional gas reservoirs in shale, dense and other low-permeable sediments. In these cases, by the method of pressure drop, it is advisable to estimate only the **drainage volume** of the reservoir and the corresponding gas reserves in it in relation to the development system used [1, 2]. When developing gas reservoirs, it is of paramount importance to have low-permeabel barriers through which gas flow occurs only at pressure gradients above a certain value of the initial pressure gradient - **IPG**. It is practically **impossible** to recovery all the gas reserves from any real reservoir.

Below is a model for developing a gas reservoir, which is a system of Multi-scale blocks separated by low-permeable barriers - **LPB**s. The model makes it possible to estimate drained and residual gas reserves **for the development system used**; in combination with the volumetric method, it allows one to estimate the volume of undrained reserves in stagnant zones, which determines the feasibility of drilling additional producing wells in large stagnant zones.

1.1. Schematic mathematical model of a gas reservoir with Multi-scale blocks structure.

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 reservoir [2]. The model does not take into account the presence of sub-vertical channels - **SVC**s in the reservoir, through which, in some cases, producing wells are water encroachment. In most cases, the volume of incoming water is small and it practically does not affect the results below (see Fig. 5).

1.2. General considerations.

A natural gas reservoir comprised of a system of gas saturated porous blocks, divided by low-permeable barriers - **LPB**s. Next, we will consider the gas reservoir, which is divided by **LPB**s into blocks (see Figures 1, 2).

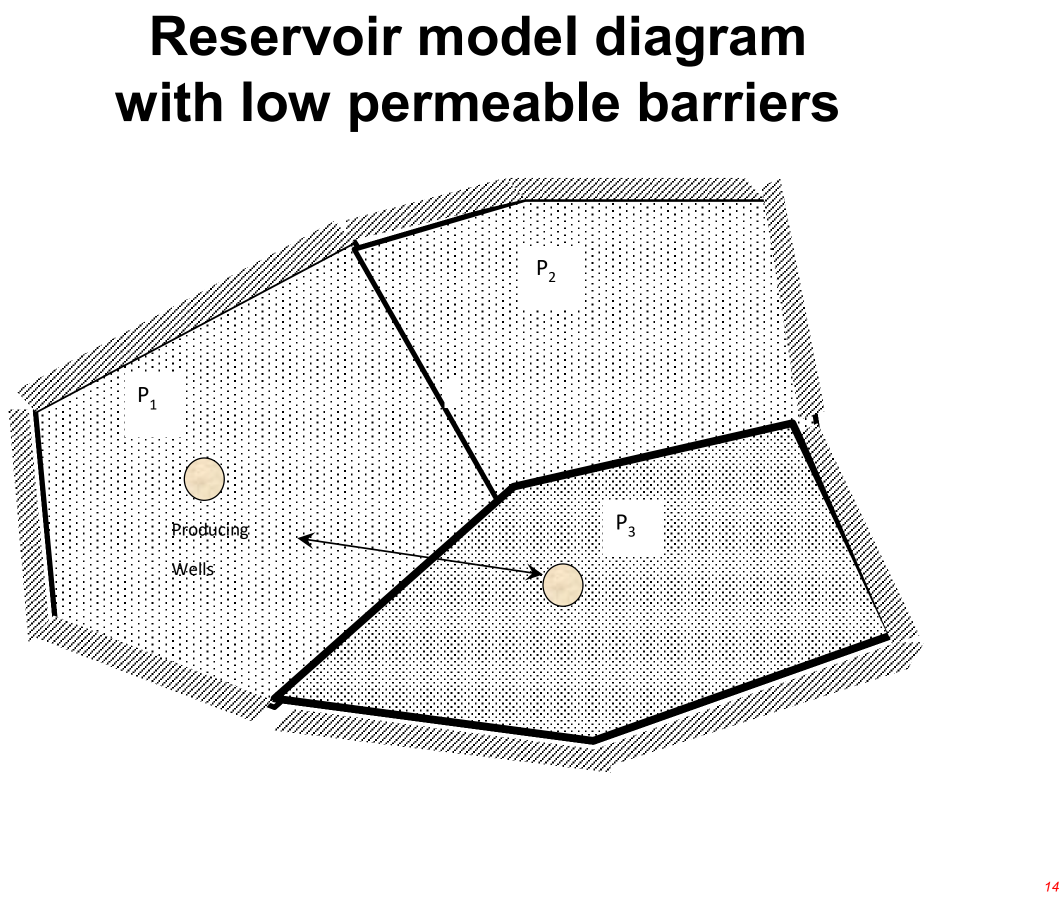


Figure 1: Reservoir model diagram with low-permeable barriers.

The thickness of **LPB**s is assumed to be small as compared to the size of separate Multi-scale blocks, and their total volume is small in comparison with the total reservoir volume. The volume of each **MSB** is also assumed to be much greater than the volume of surrounding **LPB**s. This assumption holds for most of the examined gas reservoirs [1, 3]. In modeling the gas production, the formation pressure is assumed to be uniform in the each **MSB** area. It means the neglecting volume of the block near producing well bores where most of the formation pressure drop takes place. Such assumption is justified, if we consider gas flow in a moderately permeable reservoir. The most of the reservoir flow resistance is assumed to be concentrated in the low-permeable barriers between the blocks. In mass conservation equations with such assumptions the reservoir flow resistance effects to only cross-flow between the blocks and not the flow inside the blocks. The mass conservation equation of gas in each block may be written as follows:

$$\frac{d}{dt}\left(M_i\right) = -Q_i(t) + S_{ij}\frac{k_{ij}\rho_{ij}}{\mu h_{ij}}\left(p_j - p_i\right), \qquad (1);$$

where: M_i is gas mass in the block number i; p_i – formation pressure in the i-th block; Q_i – total production of wells in the block; μ - gas viscosity; k_{ij} - the permeability of the **LPB** between the i-th and the j-th blocks; h_{ij} – thickness of the **LPB**; S_{ij} - the **LPB** area (that part of the **LPB** area through which fluid flows between the i-th and the j-th blocks).

The mass of gas in the i-th block is equal to:

$$M_i = V_i\rho_i\left(p_i\right); \qquad \mathbf{(2)};$$

where V_i is the gas volume in the block; $\rho_i(p_i)$ is gas density, which may be presented in the form

$$\rho_i(p_i) = \frac{\rho_0}{p_0}\frac{p_i}{Z_i}, \qquad (3);$$

where Z_i is compressibility factor, the function of temperature and formation pressure in the block.

The equations (1)-(3) may be considered as a system of ordinary differential equations - ODE for pressures in blocks p_i. It can be solved for the given initial formation pressures values. In the system (1) ÷ (3) the validity of Darcy's law was assumed. But in many cases the gas cross-flow through the **LPB**s occurs ***only*** if the pressure gradient exceeds some initial value, **IPG**. Then gas cross-flow through a **LPB** may be described by generalized Darcy's law with **IPG** equal to some value ***G*** [5]:

$$\text{At } \left|p_j - p_i\right| > Gh_{ij} \quad q_{ij} = -\frac{k_{ij}}{\mu h_{ij}} S_{ij}\left[(p_j - p_i) - Gh_{ij}\right]; \qquad (4);$$

$$\text{At } \left|p_j - p_i\right| \leq Gh_{ij} \quad q \equiv 0; \qquad (5).$$

The value of **IPG** can be obtained from field observations.

1.3. Two-blocks model.

The simplest model of considered gas pool comprises of two blocks separated by one **LPB** (see Figure 2).

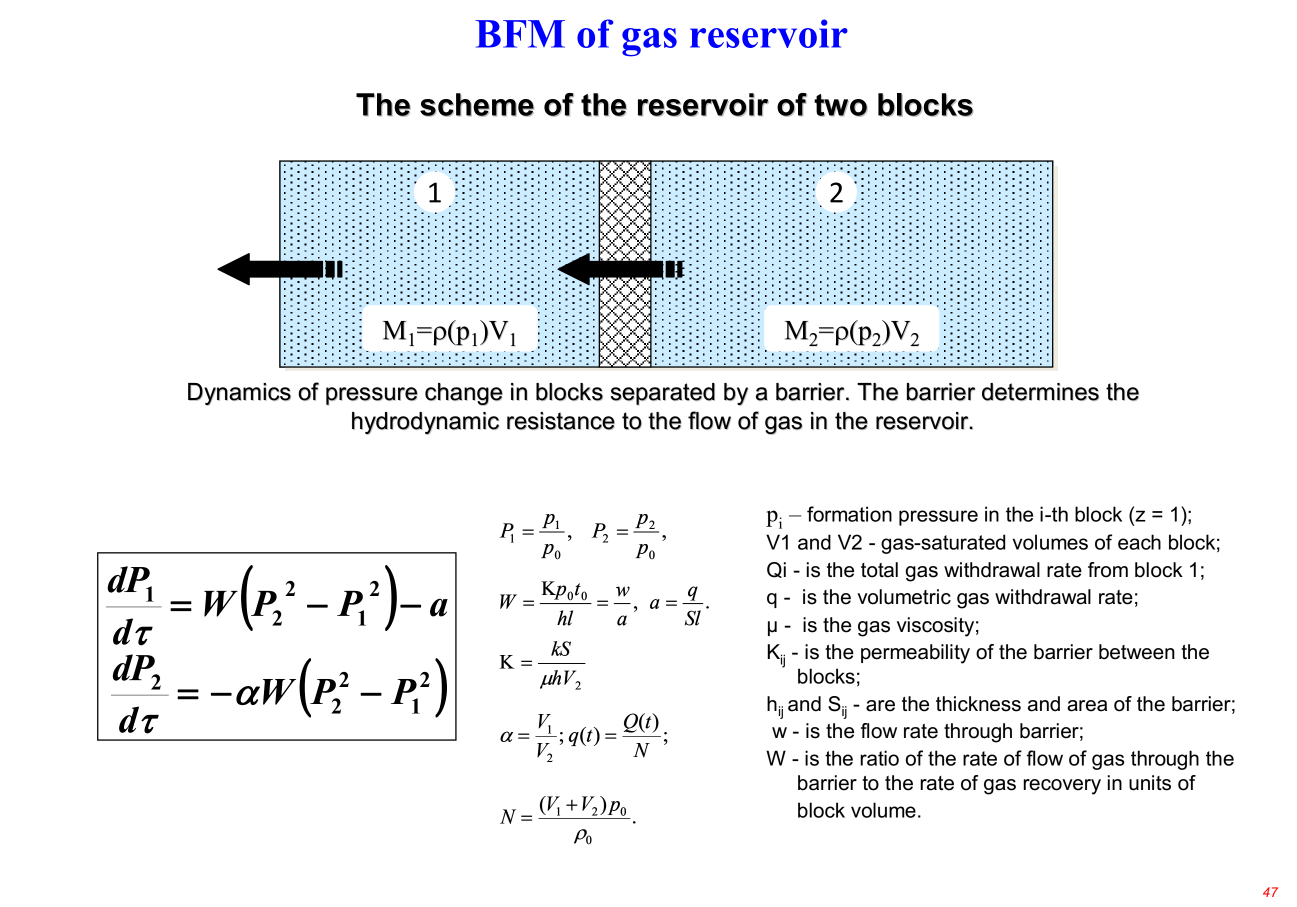


Figure 2: The scheme of the reservoir of two blocks.

Gas is produced only from one ("active") block denoted as the block 1. The cross-flow between the blocks takes place in accordance with Darcy's law. The gas production rate is equal to *Q(t)* and is considered as a function of time *t*. The gas from the "passive" block 2 first flows to the block 1 and then is produced through producing wells of the block 1. Let the volumes of each block to be V_1 and V_2 correspondingly and masses of gas in the blocks are defined as M_1 and M_2:

$$M_1 = \rho(p_1)V_1; \qquad M_2 = \rho(p_2)V_2; \qquad \textbf{(6)}.$$

To calculate the gas density in the **LPB**, we assume that the formation pressure difference in the part of **LPB** is not very large and the average formation pressure $\overline{p}$ is equal to:

$$\overline{p} = \frac{p_1 + p_2}{2}; \qquad \rho = \frac{\rho_0}{p_0}\frac{\overline{p}}{Z}; \qquad (7).$$

The examples are presented here as illustration only, and we can put Z=1 into eq. 7. With these assumptions we obtain from equations 1, 6 and 7:

$$\frac{dp_1}{dt} = \mathrm{K}\alpha(p_2^2 - p_2^2) - q(t), \qquad \textbf{(8)};$$

$$\frac{dp_2}{dt} = -\mathrm{K}(p_2^2 - p_1^2). \qquad \textbf{(9)};$$

where: $\mathrm{K} = \dfrac{kS}{\mu h V_2}$; $\alpha = \dfrac{V_1}{V_2}$; $q^*(t) = \dfrac{q(t)}{N}$; $N = \dfrac{(V_1 + V_2)p_0}{\rho_0}$.

q*(t)* - is the gas production rate.

In dimensionless form we obtain the system of equations:

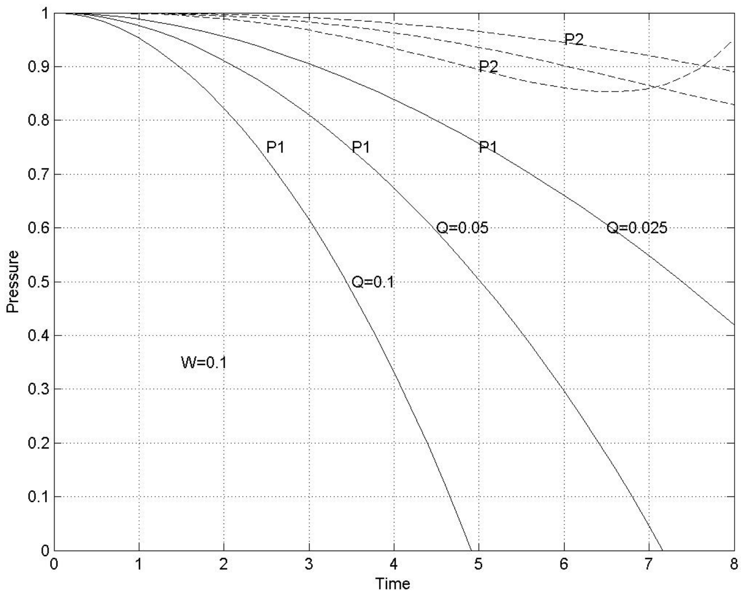
$$\frac{dP_1}{d\tau} = W\left(P_2^{\ 2} - P_1^{\ 2}\right) - a \qquad (10);$$

$$\frac{dP_2}{d\tau} = -\alpha W\left(P_2^2 - P_1^2\right) \qquad (11);$$

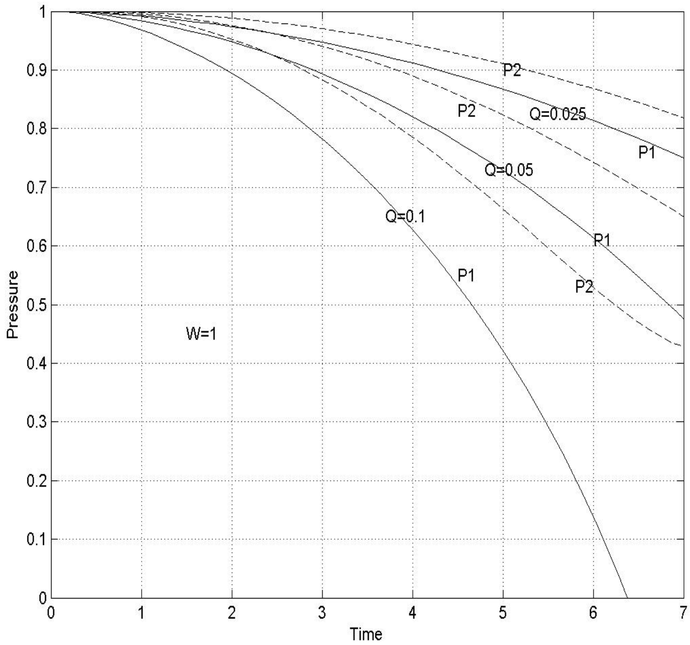
where: $P_1 = \dfrac{p_1}{p_0}$, $P_2 = \dfrac{p_2}{p_0}$, $W = \dfrac{\mathrm{K} p_0 t_0}{hl} = \dfrac{w}{a}$, $a = \dfrac{q}{Sl}$.

The parameter ***W*** is the ratio of the speed of gas flow through the **LPB1** between blocks to the relative rate of gas production, which is expressed in units of block volume; ***q*** - is the volumetric rate of production; the overflow rate **w** is proportional to the permeability of the **LPB1** and inversely proportional to its thickness.

The system of equations (10) and (11) has been solved numerically for several examples using the MATLAB software package. Some results of the calculations are shown in Fig. 3 as a function of time of the formation pressure values P_1 and P_2. The formation pressures $P_1(t)$ and $P_2(t)$ are expressed in units of initial formation pressure.



a)



b)

Figure 3 The functions ***P₁(t)*** in active block and ***P₂(t)*** in passive block at W=0.1 (**a)** and W=1 (**b)** for Q: 0.025; 0.05 and 0.1.

The $P_i(t)$ curves show the ratio of the residual gas content in each block to its initial mass as a function of time. Completeness of gas recovery from the passive block at each moment of time is equal to $|1 - P_2(t)|$. For examples, the values of **W** are 0.1 and 1; $\mathrm{K}p_0 = year^{-1}$. values of the parameter ***a*** are equal 0.025, 0.05 and 0.1.

In the Figure 3 it is seen that, at chosen production rates, **the formation pressure difference between blocks grows very significantly. The formation pressure difference is essentially dependent on the gas production rate.** Decrease in the **LPB** permeability (**W**=0.1) results in considerable growth of formation pressure difference in the **LPB**. At each value of ***q***, at some instant of time t*, the formation pressure in the active block P_1 **becomes zero and the gas production stops**. The early depletion of the active block is less pronounced for large values of the conductivity of the **LPB - W** (see Fig. 3 at **W**=1).

Thus, **at low values of the conductivity of the LPB -W, the completeness of the gas recovery from the passive block is much lower than that of the active block and depends significantly on the rate of gas production**. **To increase the completeness of gas recovery from the passive block, it requires the input of producing wells in the passive block.**

The parameter A* is used to evaluate the filtration resistance of large pool elements [6]:

$$A^*(t) = \frac{p_2^2 - p_1^2}{Q_i}, \qquad (12),$$

Q_i *is* the total gas production at the time t.

Based on the results of model calculations, we can estimate the dependence of the parameter $A*$ on time. **If this dependence is weak**, the parameter $A*$ can be used as a constant characteristic of the filtration resistance to the flow of gas for a given element of the pool. In Figure 4 the calculated time dependence curves of the quantity $A^*(t)$ are shown:

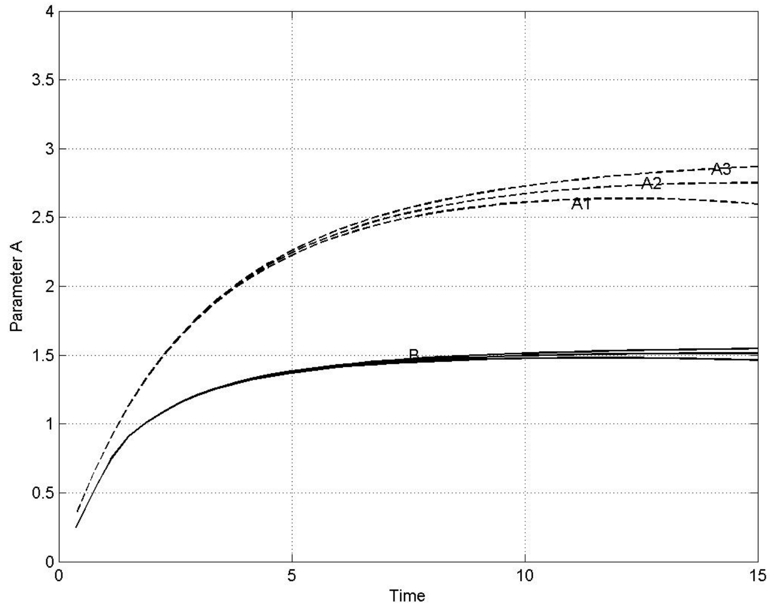


Figure 4: The curves $\boldsymbol{A^*(t)}$ for the same examples as in Figure 3 (a) and 3 (b). The curves for examples *B1, B2* and *B3* almost merge and are marked only by letter B.

The dependencies $A*(t)$ in Fig. 4 are calculated for the same examples as in Fig. 2 (respectively, curves A (**W**=0.1) and B (**W**=1)). The data presented in Figure 3 and the results of other calculations show the following:

- **The values of the parameter A* significantly depend on the permeability of the LPB**.
- **The type of dependences A*(t) depends on the rate of gas recovery mainly at low permeability of the LPB**.
- In the first approximation, and at low values of W, the parameter A* can be used as a **LPB** characteristic of the filtration resistance.
- After the total production reaches about 10-20% of initial reserves, the value of $A^*(t)$ almost does not change with time for the given **LPB** properties.
- **In pools of Multi-scale block structure, the filtering properties of the LPB**s **have a much greater effect on the value of the parameter** A* **than the rate of gas production.**

These conclusions are consistent with the results of analysis of the field data [1]. This implies that the value of A^* **may be used as a parameter describing LPB flow properties.**

From the results of calculations it is evident that the parameter A^* may characterize the flow properties of **LPB**s, dividing the producing part of the pool from parts lacking producing wells. The parameter A^* is **less informative, if the annual production is more than** 5% of total reserves in the producing block, and when **the total production is more than** 50% of reserves. The capability of using the value A^* as a characteristic of **LPB** properties is also confirmed by the estimates of A^* at the gas pools of the Gazli and the Yamburgskoye fields, as it is seen in [2].

The pressure distribution in pool is more complicated if the gas flow is governed by the seepage law with **IPG** described by equalizations 4 and 5. In this case the exact solution of flow equations is rather complicated. As a first approximation we may add the value G_gh to the formation pressure difference calculated using system of equalizations 10 and 11. The value of **IPG**, ***Gg***, as a constant or usually *the* **function of p_{ef} must be estimated using field data** [7].

To take into account the existence of **IPG** for gas flow, the following modification of eq. 11 may be used:

$$(P_{i1}/z_{i1})^2 - (P_{i2}/z_{i2})^2 = A^* Q_i + B(p_{ef})/(z_{i2})^2 \; ; \qquad (13);$$

where: $Q_i=0$; $\quad if \quad |p_{i2} - p_{i1}| \, h^{-1} \leq Gg$

The eq. (13) is valid to describe gas production in the pool, when the flow through the **LPB** takes place with **IPG** for gas flow. For the constant ***B*** the following equation may be used:

$$\sqrt{B(p_{ef})} \approx Gh \; ; \qquad (14).$$

The value of $B(p_{ef})$ characterizes the **LPB** filtration properties, if they are not taken into account in estimating the value of the parameter A^*, or the properties of the **LPB** have changed, in particular, due to an increase in p_{ef} as the formation pressure in the reservoir drops. Here h is the thickness of **LPB** with **IPG** for gas filtration. The value of the parameter A^* in eq. 12, in the first approximation, can be assumed constant, while the formation pressure during the gas production is decreased. This follows from an analysis of the estimates of the values of the parameter **Ř** (productivity **Ř**=$|P_{fi}^2$ **-** $P_{bi}^2|$**=const**) for the producing wells of the gas reservoir IX of the horizon of the Gazli and Cenomanian gas reservoir of the Yamburgskoye fields, as well as the estimates of the parameter A^* for the elements of the gas reservoirs within the limits results of the model calculations (see below). Estimates of the **LPB** parameters according to formulas 13 and 14 characterize **the minimum of LPB** filtration resistance at the current value of p_{ef}.

1.4. Estimations of the reservoir drainable volume and residual gas reserves.

Assuming that the reservoir may be described by a model consisting of N **MSB**s, the ensured gas reserves in the reservoir may be estimated by the value of a drainable volume V_{dr}, calculated (not taking into account the temperature correction) as:

$$V_{dr} = \sum_{I=1}^{N} \frac{\Delta Q_i}{\left(\frac{p_{i1}}{Z_{i1}}\right) - \left(\frac{p_{i2}}{Z_{i2}}\right)} ; \qquad (\mathbf{15});$$

where: ΔQ_i is the total gas production from the well number ***i***, while the formation pressure is decreased from p_{i1} to p_{i2}; Z_{i1} and Z_{i2} are the values of Z, corresponding to P_{i1} to and P_{i2}; N – quantity of producing wells at the production ΔQ_i.

The value of V_{dr}, calculated by eq. 15, gives a **minimum** ensured estimate of gas resources (provided that great mass of edge and bottom water did not invade into the pool) whereas ***maximum*** residual recoverable gas reserves - ΔV (with the assumption that the current value of drainable volume remains invariable) are equal to:

$$\Delta V = V_{dri}\left(\frac{p^*}{Z^*} - \frac{p_c}{Z_c}\right), \qquad (16);$$

where: P^* is the minimum current formation pressure in the production zones; P_c - its designed final value of formation pressure.

The value of the residual recoverable gas reserves, which is calculated according to eq. 16, is **the maximum value** under the assumption that the used reservoir development system will be preserved and in the future; because when calculating it, it is assumed that the **IPG** values will not increase between the existing gas recovery zones and the **MSB**s in which there are no producing wells. Accordingly, it is necessary to locate the probable position of **LPB1**s and to drill additional producing wells in stagnant zones, if the probable gas reserves in these zones are significant (estimated gas reserves by the volumetric method) for increasing the completeness of gas recovery from the reservoir.

1.5. Examples of assessing drainage volumes of gas reservoirs.

If the reservoir is hydro dynamically uniform and interconnected the value of V_{dri} must be time **constant**. If the reservoir is divided by **LPBs,** the value of V_{dri} **will vary**, depending on the pressure drop in the production zones, the location of the producing wells and the rate at which gas is produced from the reservoir. The main changes in the value of V_{dri} should be determined by the intensity of the gas cross-flow through the **LPBs** into the production zones from those parts of the reservoir in which there are no producing wells. At the initial stage of development for all studied reservoirs maximum estimates of V_{dri} were obtained in the time of **GRF** ≥0.1÷0.3 [1]. In most cases these maximum estimates of V_{dri} were **less** than the gas-saturated volumes of these reservoirs, according to his estimates by the volumetric method. At the early stage of gas production the estimated value of V_{dri} was increasing, i.e. the part of gas reserves, from which the gas was taken, increased. After a significant drop in formation pressure, and when **GRF**>~0.3, the values of V_{dri} decreased, and cones of depressions around producing wells increased, even when the gas production rate decreased. Producing wells placement systems and the timing of their putting into operation have significant impact on the form of the dependences V_{dri}/V_{dro}=f$(P_{f0}$-$P_{fi})$.

The results of assessing changes in the drained volumes of gas reservoirs in the 1X horizon of the Gazli field and in the Cenomanian gas reservoir of the Yamburgskoye field are presented in Fig. 5.

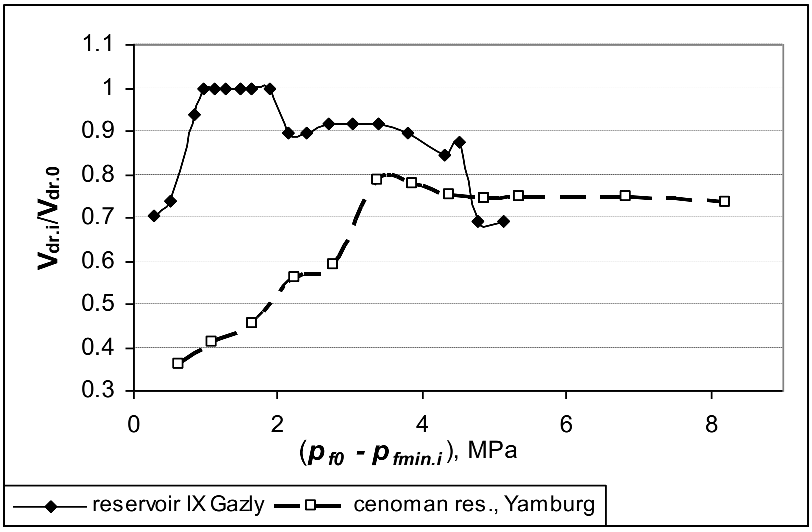


Figure 5: Variations of drainage reservoir volume with decrease of the formation pressure in gas reservoir IX horizon of the Gazli and the Cenomanian gas reservoir of Yamburgskoye fields.

The reservoirs are composed of highly porous and highly permeable terrigenous deposits, but differ in area, initial location of producing wells and intensity of neotectonic movements. The Cenomanian reservoir has an area of ~8500 km^2, within its boundaries, the Yamburg anticline high (area ~45x75 km, amplitude ~200 m) and adjoining to it the Kharvutinskoye anticline high (area ~20x35 km, amplitude ~60 m) were identified. The initial producing wells were concentrated in the roof of the Yamburg high. The results of aerospace observations were recorded there are numerous lineaments' in the area of the reservoir, recording the results of neo-tectonic movements [2].

The gas reservoir in the 1X horizon has an area of ~560 km^2 and an amplitude of ~250 m. The gas reservoir by the beginning of development was drilled with producing wells, the distance between the wells was ~1 km, mainly in the zone of the absence of bottom water, in which contained ~70% of the initial gas reserves. In the area where the producing wells were located, 4 blocks were identified, which at the beginning of reservoir development were separated by low-permeabeil barriers with initial pressure gradient values within 0.1 MPa/m, the difference in reservoir pressures in these blocks was within 0.16 MPa [2]. The presence of **LPB**s in the reservoir was clearly demonstrated by the results V_{dri} assessments at different stages of its development. At the beginning of gas production of the reservoir in horizon IX, when the formation pressure decreased by ~1 MPa, the drainable volume values were at a maximum, approximately equal to the estimate of initial gas volume in the reservoir by the volumetric method. By this time, the reservoir developed in a depletion drive under the gas regime. The decrease of V_{dri} value by ~10% was noted at **GRF**≈0.3 and the P_{f0} decreased by about 2 MPa. When the formation pressure decreased by ~4.5 MPa, the distinct decreasing of V_{dri} by ~30% was noted (see Figure 5). At these P_{fi} values, the growth of parameter A^* also took place [2]. Consequently, at **GRF**≈0.3 in the reservoir decreased the intensity of gas cross-flow to the production activity zones from the reservoir parts in which there are no producing wells, that is, new **LPB**s have arisen inside the reservoir and the **IPG** values increased as the gas flowed through the initially existing **LPB**s. The pressure differences at the **LPB**s grew gradually up to ~**1.5** MPa. This means that while the total gas production was <**60**% of initial reserves, the **IPG** values sufficient to enable flow through **LPB**s grow from approximately zero to ~2 MPa/m (this value correspond to the barrier thickness conditionally equal to ~1 m). The appearance of additional meaningful barriers in the reservoir and the growth of the reservoir resistance to the gas flow are responsible for the decrease of *Vdri* of the reservoir.

At the beginning of the Cenomanian gas reservoir gas production, a slow increase V_{dri} value and a significant reduction in the formation pressure in the gas production zones took place. This occurred with the active introduction of new producing wells in parts of the reservoir that are remote from the reservoir roof. The maximum V_{dri} value (hereinafter V_{drimax}) was determined during the period of the maximum rate of gas production after putting into operation of practically all designed producing wells. At this time, more than 500 producing wells were located in the zones of maximum thickness of productive deposits. The V_{drmax} value was at least 20% less than the initial gas reserves were calculated by volumetric method with ~10% accuracy [2]. In year 11 of reservoir development, a small decrease in the V_{dri} value was noted, along with a decrease in the P_{f0} value in the gas production activity zones by ~4.5 MPa. With a decrease in P_{f0} by ~8 MPa, an additional decrease in the V_{dri} value was noted. In the year 13 of the reservoir development, the number of producing wells in the peripheral parts of the reservoir increased with respect to the development project on the basis of observations of formation pressure dynamics in the reservoir and due to the forced reduction in the rate of gas production. After 17 years of production at **GRF**≈0.5, the formation pressure drop in some observation wells was much greater than its predicted value. At the same time in some marginal parts of the pool the $\boldsymbol{P_{f0}}$ value was preserved **[2]**. This is due to the fact that at each **LPB** there is a spasmodic change in formation pressure in the developed reservoir. The position of all barriers in this case was not established, since no special observations were carried out for a more complete study of modern geodynamics within the area of the Yamburgskoye field. As a result, in this time the $\boldsymbol{V_{dri}}$ value was at least **30% less** than predicted based on the initial gas reserves. Badly drainable parts of the reservoir separated from producing wells by neo-tectonic faults, the growth of formation pressure differences between wells was distinctly noted, independently of production rate**.** The results confirm the correctness of the above conclusions and illustrate the possibility of their practical use. Additional drilling of more than 100 producinп wells in stagnant zones made it possible to increase the drainable gas reserves in the reservoir by ~1 trillion.m^3; initial annual additional gas production from newly drilled wells exceeded 35 billion m^3.

It should be noted that Equations 15 and 16 are applicable when reservoir development occurs in substantially gas drive. If there is active penetration of edge water into the reservoir, these equations do not allow obtaining reliable information. In Fig. 6 shows the results of observations of the dynamics of the drained volume of the gas reservoir of the Leningradskoye field. The gas reservoir is confined to an anticlinal structure with 5 domes in terrigenous deposits of the Lower Cretaceous, the thickness of productive deposits varies from ~100 m to ~185 m, the depth of the roof is ~2000÷2180 m, P_{f0}~22.7 MPa [8]. Prior to development, the reservoir was evenly drilled by producing wells in areas with a gas-saturated thickness of ≥40 m, within which most of the initial gas reserves were contained. After ~1 year of development, with a slight decrease in the P_{f0} value, almost the entire volume of the reservoir was drained according to its estimates by the volumetric method. After 5 years of development of the reservoir, with the value of **GRF**~0.2, the active water drive has appeared. After 10 years of the reservoir development, a sharp decrease in V_{dr} was noted, which necessitated a reduction, and then almost cessation of industrial gas production at **GRF**<0.5 (see Fig. 6).

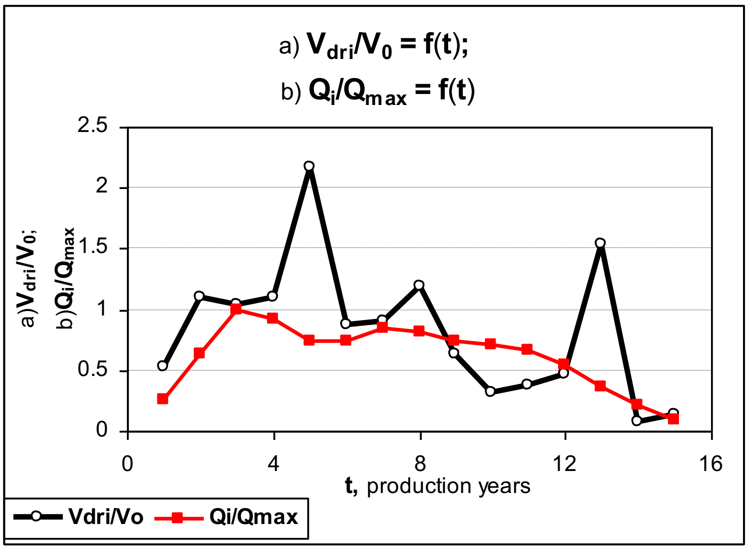


Figure 6: Dependences of V_{dri}/V_{dr0} and the rate of annual gas recovery Q_i/Q_{max} on the duration of the development of the gas reservoir (**t,** production years) of the Leningradskoye field.

Intensive water encroachment of almost all producing wells, in which productive deposits were penetrated, significantly removed from the initial **GWC**, is probably due to water breakthroughs through sub-vertical channels after the formation pressure in the pool has decreased by a value of ΔP, which is higher than the **IPG** values for water movement through the **SVC**s. **Estimates of the drainage volume with the active water drive are not representative** and allow **only** fixing the uneven rate of water introduction over time, as well as a sharp decrease in the drainage volume during periods when production rates are reduced and the bottom and edge water introduction. Local water breakthroughs led to the stopping of industrial gas production from a number of fields in the Krasnodar Territory of the USSR.

Conclusion

The completeness of oil and gas recovery can be significantly increased by taking into account the identified natural phenomena in the process of exploration and development of hydrocarbon fields and expanding the complex of studies to identify zones of neotectonic dislocations based on the results of interpretation of aerospace images, 3D seismic exploration and hydrodynamic studies.

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