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THE TECHNIQUE OF EARLY DETERMINATION OF RESERVOIR DRIVE OF GAS CONDENSATE AND VELOTAIL OIL DEPOSITS ON THE BASIS OF NEW DIAGNOSIS INDICATORS

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Abstract. The purpose of this study is to find new indicators to characterize the drive mechanism and develop a method for early determination of reservoir drive. The results of our investigation showed that there is a strict relationship between the reservoir drive and the relations of pore volume to reservoir pressure and porosity. New diagnosis indicators to help identify the drive mechanism called Reservoir Drive Performance Indexes (RDPI) have been found. A technique based on RDPI for early determination and characterization of the drive mechanism of gas-condensate, volatile and black-oil reservoirs has been developed.

Keywords: reservoir drive, drive mechanisms, production data analysis, identification, aquifer performance, gas-condensate, volatile oil.

AMS Subject Classification: 76-06.

1. Introduction

To date, the hydrodynamics of the reservoir system is rather highly developed [1, 10, 11]. Mathematical models for the development of oil and gas fields have been developed for the most geological and technological conditions [3-7]. However, without solving some fundamental problems, which is the problem of determining the reservoir-drive, the obtained results are only theoretical. Therefore, in this paper the main attention is paid to the problem of determining reservoir-drive.

It is known that the pore pressure is the main energy source of a reservoir. It facilitates the flow of fluid to the bottom hole. At the same time, the nature of the forces that create pore pressure is called a reservoir drive. The proper identification of the reservoir drive plays a crucial role in designing the development of oil and gas reservoirs.

In the literature reservoir drive mechanisms are classified as follows: 1. Solution gas drive; 2. Gas cap drive; 3. Water drive; 4. Gravity drainage; 5. Combination or mixed drive.

According to this classification, a water drive can be strong (or full or complete) or partial. This classification can be illustrated by the scheme presented in Figure 1 [15].

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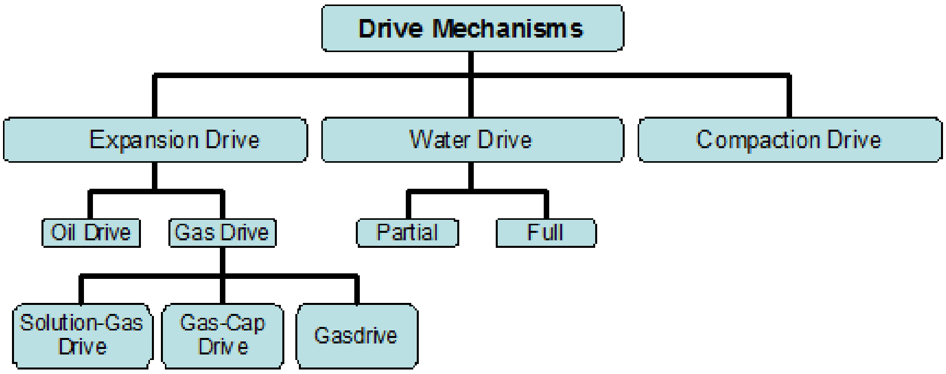

Figure 1. The classical classification of drive mechanisms.

The analysis of reservoir drive mechanisms shows that there are two types of energy sources of reservoir systems - exhaustible and inexhaustible energy sources. If we consider the above noted reservoir drive mechanisms on this basis, we can see that the Solution gas drive, Gas cap drive, Gas drive, Oil drive and Compaction drive are the drive mechanisms in which reservoir energy is depleted relatively quickly with production. The duration of the depletion of the reservoir energy depends on the elastic reserve of the formation system. Within this paper, such drive mechanisms are called elastic drives. So, the energy in the elastic reservoir systems is generated basically by a set of elastic forces.

There can be two cases in the water drive. In the first case, the aquifer has a much larger volume than the reservoir or is in communication with surface recharge. Therefore there is no intensive decline in the reservoir pressure. A drive mechanism of this type will be called a strong-water drive.

In the second case, when the aquifer does not have a huge volume due to the relatively rapid depletion of energy of the aquifer, there is an intense pressure decline in the reservoir. In this case, the drive mechanism is called an elastic-water or water-expansion drive.

Considering the aforesaid the drive mechanism should be classified as the scheme shown in Figure 2.

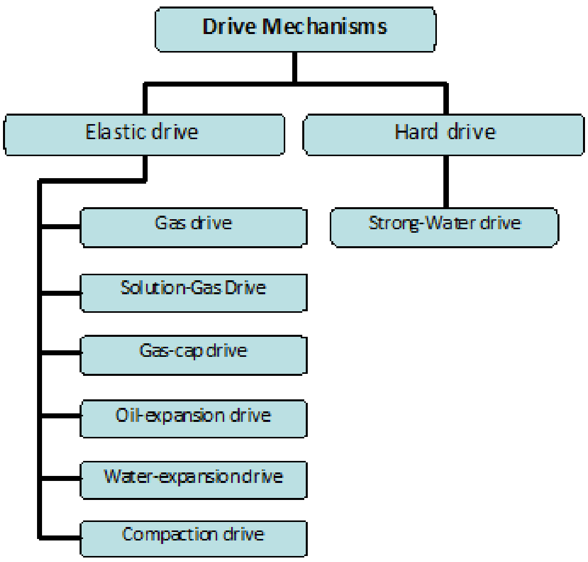

Figure 2. The classification of drive mechanisms by the energy source type.

Many years of experience in developing oil and gas fields shows that even a general classification of reservoir drive mechanisms is conditional, because both types of force can participate in the actual reservoir systems in the shaping of the reservoir pressure. But only the dominating one defines the reservoir drive [9].

Determining the nature of the forces that shape the reservoir pressure, including the nature and aquifer activity index allows to identify the reservoir drive and is of great importance for the designing of development.

The earliest possible determination of the drive mechanism is a primary goal before designing development and it can greatly improve the management and recovery of reserves from the reservoir. The existing methods for the determination of reservoir drive is mainly based on the trend analysis of the pressure and GOR [12-14]. These techniques require more data, are based on a subjective evaluation and do not provide the required reliability.

In the books by Zakirov [16] the mentioned approach is applied to gas fields, taking into account the compaction of formation. The account of compaction increases the reliability of the mentioned approach for determination of the drive mechanism but does not change the aim of the said method. In the cases of insufficient historical field data the determination of reservoir drive by a curve shape is even more difficult and unreliable. The aim of this work is to find some indexes characterizing the energetics of the reservoir and to develop a more reliable method for determining the reservoir drive mechanism on the basis of such indexes.

2. Reservoir drive performance indexes (RDPI)

It is known that during the development of oil and gas reservoirs the volume of reservoir is decreasing. This can occur due to both the compaction of reservoir rocks and the water influx in the reservoir. So, in the development of oil and gas reservoirs the pressure drop causes the compaction of the reservoir rocks and the invasion of edge water to the field. Both the porosity decrease and the invasion of the edge water into the reservoir compensate for the pressure decline. However, when the aquifer has a high productivity index the reservoir pressure usually has a high current value. When the aquifer is missing or it has a low productivity index the reservoir pressure has a high decrease rate. In view of the above mentioned, a decrease in the volume of reservoir in relation to the reservoir pressure drop (i.e. the ratio of the volume decrease and pressure drop) should allow evaluate the aquifer productivity index and can characterize the reservoir drive mechanism.

The purpose of this paper is to study the regularities between the decrease in reservoir pore volume and the change in reservoir pressure in various reservoir drives, detect new indicators to characterize the aquifer productivity and develop a new methodology for determining the reservoir drive mechanism. To do this, numerous calculations have been carried out for a hypothetical gas condensate reservoir developed at different production rates and in various geological conditions. During these calculations compressible and non-compressible formations, the cases of gas and water drives of different aquifer productivity indexes were considered. For this purpose, algorithms and the calculation formulas obtained on basis of the binary model of a gas-condensate system were used. Within the binary model of a gas-condensate system the filtration of a gas and condensate mixture in compressible porous media is represented by the following system of differential equations [2, 8, 11]:

$$\frac{1}{r}\frac{\partial}{\partial r}\left\{r\left[\frac{k_g(s)p\beta[1-c(p)\bar{\gamma}(p)]}{\mu_g(p)z(p)p_{at}}+\frac{k_c(s)S(p)}{\mu_c(p)B(p)}\right]k(p)\frac{\partial p}{\partial r}\right\}=$$

$$-\frac{\partial}{\partial t}\left\{\left[\frac{(1-s)p\beta[1-c(p)\bar{\gamma}(p)]}{z(p)p_{at}}+s\frac{S(p)}{B(p)}\right]\phi(p)\right\} \quad (1)$$

$$\frac{1}{r}\frac{\partial}{\partial r}\left\{r\left[\frac{k_g(s)p\beta c(p)}{\mu_g(p)z(p)p_{at}}+\frac{k_c(s)}{\mu_c(p)B(p)}\right]k(p)\frac{\partial p}{\partial r}\right\}=-\frac{\partial}{\partial t}\left\{\left[\frac{s}{B(p)}+(1-s)\frac{p\beta c(p)}{z(p)p_{at}}\right]\phi(p))\right\} \quad (2)$$

where parameters with the c and g indexes correspond to liquid and gas phases respectively; $\bar{\gamma}$ is the ratio of the specific weights of heavy components in the liquid and vapor state at reservoir pressure.

It is known [10] that in the case of elastic deformation the change in porosity and permeability obeys the exponential law and is determined by the following expressions:

$$\phi=\phi_0\exp[c_m(p-p_0)]andk=k_0\exp[c_k(p-p_0)] \quad (3)$$

Equations (1), (2) describe the motion of gas and liquid condensate in a porous medium, respectively. They are nonlinear partial differential equations. For the linearization we shall apply the averaging method.

So, applying the function H, analogous to the Khristianovich function

$$H=\int\varphi(p,\rho)dp+const, \quad (4)$$

where integrand $\varphi=\left[\frac{k_g(s)p\beta[1-c(p)\bar{\gamma}(p)]}{\mu_g(p)Z(p)p_{at}}+\frac{k_c(s)S(p)}{\mu_c(p)B(p)}\right]k(p)$.

Applying the method of averaging over r to the right-hand side of equation (1), we rewrite (4) in the following form [2]:

$$\frac{1}{r}\frac{\partial}{\partial r}\left\{r\frac{\partial H}{\partial r}\right\}=-\Phi(t), \quad (5)$$

where $\Phi(t)$ is yet an unknown function.

Equation (5) is easily solved with respect to the pseudo-pressure (H) at the following boundary conditions corresponding to the depletion-drive:

$$r=R_b,\quad H=H_b(t);$$

$$r=r_w;\quad H=H_w(t)$$

and

$$\frac{\partial H}{\partial r}_{r=R_b}=0$$

and it is possible to obtain an expression for determining the instantaneous value of well production in the following form:

$$q=\frac{2\pi h(H_b-H_w)}{\ln\frac{R_b}{r_w}-\frac{1}{2}} \quad (6)$$

To use (6), a transition from pseudo-pressure drop (H_b-H_w) to true pressure drop (p_b-p_w) is necessary. For this purpose, the integrand φ was investigated and it was established that it can be approximated by a logarithmic function in the form:

$$\varphi=a\ln(p)-b \quad (7)$$

In this case, the expression for calculating (H_b-H_w) is obtained by integrating (4) within the range of $[p_w,p_b]$ taking into account (7):

$$H_b-H_w=a\left[p_b\ln p_b-p_b-p_w\ln p_w+p_w\right]-b(p_b-p_w) \quad (8)$$

where the expression for the calculation of the coefficients a and b was obtained from (4) and (7), taking into account the corresponding boundary conditions in the following form:

$$a = \frac{\varphi_b - \varphi_w}{\ln \frac{p_b}{p_w}}, \quad b = \frac{\varphi_b - \varphi_w}{\ln \frac{p_b}{p_w}} \ln p_b - \varphi_b \tag{9}$$

Here, φ_b, φ_w are the values of φ at the boundary and bottom hole pressures p_b and p_w, respectively.

To calculate the instantaneous well production rate, we rewrite (6) taking into account (8) and (9) in the following form:

$$q_g = \frac{2\pi h \left\{ \frac{\varphi_b - \varphi_w}{\ln \frac{p_b}{p_w}} \left[\frac{\ln p_b^{p_b}}{\ln p_w^{p_w}} - p_b + p_w \right] - \left(\frac{\varphi_b - \varphi_w}{\ln \frac{p_b}{p_w}} \ln p_b - \varphi_b \right)(p_b - p_w) \right\}}{\ln \frac{R_b}{r_w} - \frac{1}{2}} \tag{10}$$

To determine the reservoir pressure p_b and the pore saturation s of the liquid phase at any time, we use the equations of the following material balance of gas and liquid:

$$q_g = -\frac{d}{dt} \left[\frac{(1-s)p\beta}{z(p)p_{at}} [1 - c(p)\bar{\gamma}] + \frac{s_c S(p)}{B(p)} \right] \Omega(p), \tag{11}$$

$$q_c = -\frac{d}{dt} \left[\frac{s}{B(p)} + (1-s)\frac{p\beta c(p)}{z(p)p_{at}} \right] \Omega(p), \tag{12}$$

where pore volume $\Omega(p) = \pi(R_b^2 - r_w^2)h\phi(p)$.

The following differential equations are obtained from (11) and (12):

$$\frac{dp}{dt} = -\frac{\frac{q_g}{\Omega_0 \bar{\Omega}}(\alpha_4 + \frac{\alpha_2}{G}) - (\alpha_2\alpha_3 + \alpha_1\alpha_4)\frac{1}{\bar{\Omega}}\frac{d\bar{\Omega}}{dt}}{(\alpha_5 + \alpha_6)\alpha_4 + (\alpha_7 + \alpha_8)\alpha_2} \tag{13}$$

$$\frac{ds}{dt} = -\frac{\frac{q_g}{\Omega_0 \bar{\Omega} G} + (\alpha_7 + \alpha_8)\frac{dp}{dt} + \alpha_3 \frac{1}{\bar{\Omega}}\frac{d\bar{\Omega}}{dt}}{\alpha_4} \tag{14}$$

where gas condensate rate

$$G = \frac{\frac{\bar{\mu}(p)B(p)p\beta}{z(p)p_{at}}[1 - c(p)\bar{\gamma}(p)] + \frac{S(p)}{\psi(s)}}{\frac{1}{\psi(s)} + \frac{\bar{\mu}(p)a(p)p\beta c(p)}{z(p)p_{at}}}, \frac{1}{\psi(s)} = \frac{k_g}{k_c};$$

$$\bar{\mu}(p) = \frac{\mu_c}{\mu_g}; \quad \alpha_1 = (1-s)\frac{p\beta}{z(p)p_{at}}[1 - c(p)\bar{\gamma}(p)] - s\frac{S(p)}{B(p)}, \quad \alpha_2 = \frac{p\beta}{z(p)p_{at}}[1 - c(p)\bar{\gamma}(p)] - \frac{S(p)}{B(p)},$$

$$\alpha_3 = s\frac{1}{B(p)} - (1-s)\frac{p\beta c(p)}{z(p)p_{at}}, \quad \alpha_4 = \frac{1}{B(p)} - \frac{p\beta c(p)}{z(p)p_{at}}, \quad \alpha_5 = (1-s)\left\{ \frac{p\beta}{z(p)p_{at}}[1 - c(p)\bar{\gamma}(p)] \right\}',$$

$$\alpha_6 = s\left[\frac{S(p)}{B(p)}\right]', \alpha_7 = s\left[\frac{1}{B(p)}\right]', \quad \alpha_8 = (1-s)\left[\frac{p\beta c(p)}{z(p)p_{at}}\right]'; \tag{15}$$

"$'$" – means the derivative with respect to p.

In equations (13) and (14), $\bar{\Omega}$ and $\frac{d\bar{\Omega}}{dt}$ in the case of elastic formations are determined taking into account (3) as follows:

$$\bar{\Omega} = \frac{\Omega}{\Omega_0} = \exp[c_m(p - p_0)] \ \ and \ \ \frac{d\bar{\Omega}}{dt} = c_m \exp[c_m(p - p_0)]\frac{dp}{dt} \tag{16}$$

Taking into account (16), we rewrite the equations for determining the values of reservoir pressure and condensate saturation (13) and (14) in the following form:

$$\frac{dp}{dt} = -\frac{\frac{q_g}{\Omega_0 \bar{\Omega}}(\alpha_4 + \frac{\alpha_2}{G})}{(\alpha_5 + \alpha_6)\alpha_4 + (\alpha_7 + \alpha_8)\alpha_2 - (\alpha_2\alpha_3 + \alpha_1\alpha_4)\frac{a_m}{\bar{\Omega}}e^{a_m(p-p_0)}} \tag{17}$$

The system of ordinary differential equations (14), (16), (17) is solved taking into account (10) by one of the numerical methods. It allows to determine the well production rate, the reservoir pressure and the condensate saturation at any time during the development of the reservoir, represented by elastic rocks. In the same way, analogous differential equations and an expression for determining the well production rate for the case of a water-drive were obtained.

The algorithm outlined above makes it possible to predict the main parameters of the development of a gas condensate deposit represented by elastic reservoirs.

On the basis of this algorithm, a computer simulator was created, which allowed to simulate the process of development of the gas condensate deposit under various geological and technological conditions. By this simulator, numerous computer experiments were performed for a hypothetical gas condensate deposit, developed at different rates of gas extraction from the reservoir. Deformable and non-deformable reservoirs, cases of depletion, elastic and strong water-drive were considered and regularities between decrease in the pore volume of the productive part of the deposit and changes in reservoir pressure were studied. The following input data were used for calculations:

Original reservoir pressure: $p_0 = 46.3\ MPa$;

Original permeability: $k_0 = 0.1\,10^{-12}m^2$;

Formation thickness: $h = 20\,m$;

Wellbore radius: $r_w = 0.1\ m$;

Formation compaction factor: $c_m = 0$ and $0.1\ MPa^{-1}$;Gas production rate (in percent of the original gas in place volume per year): 10 and 20.

Various computer experiments have been carried out in the simulator created on the basis of equations (14), (16), (17) and (10). The process of development in gas, water-expansion and strong-water drives was investigated by using the above-mentioned values of production rate and the following parameters were defined:

$$\bar{\Omega}_p = \bar{\Omega}/_{\bar{p}}, \quad \bar{\Omega}_m = \bar{\Omega}/_{\bar{\phi}}$$

where $\bar{\Omega}$ is the ratio of current reservoir pore volume (Ω) to its original value (Ω_0); $\bar{\phi} = \frac{\phi(p)}{\phi_0}$ is the ratio of current formation porosity to its original value; $\bar{p} = \frac{p}{p_0}$ is the ratio of current and original reservoir pressure;

In the calculations it was assumed that the formation compaction obeys an exponential law and thus, the porosity corresponding to current reservoir pressure (p) is defined by the following expression [10]:

$$\phi = \phi_0 \exp[c_m(p - p_0)] \tag{18}$$

where ϕ_0 is initial porosity.

The obtained values of $\bar{\Omega}_p$ and $\bar{\Omega}_m$ at different relative reservoir pressures ($\bar{p}$) are shown in Table 1. The table also indicates the values of cumulative gas production (Q_g) and condensate (Q_o) corresponding to those reservoir pressures.

It should be noted that when the aquifer is inactive the current value (i.e., a value corresponding to current reservoir pressure (p) of pore volume of the reservoir was calculated by the following formula taking into account the law of porosity change:

$$\Omega = \pi R_b^2(t) h \phi(p) \tag{19}$$

And when an aquifer is active the function is determined by the solution of the corresponding problem in the present model.

Table 1. Values of the $\bar{\Omega}_p$ and $\bar{\Omega}_m$ parameters for various reservoir drive mechanisms.

Actual reservoir drive mechanism	$\bar{p}$	Q_g, $10^3\,m^3$	Q_s, $10^3\,m^3$	$\bar{\Omega}_p$	$\bar{\Omega}_m$	Expected drive mechanism
Incompressible reservoir ($q_g = 10$ % of original gas in place volume per year)						
Gas drive	0.914 0.833 0.760	23386.9 46773.8 70160.7	6.6119 12.5788 17.9457	1.094 1.200 1.315	1.000 1.000 1.000	Gas drive
Water-expansion drive	0.915 0.834 0.761	23386.9 46773.8 70160.7	6.6208 12.5971 17.9718	1.091 1.197 1.312	0.999 0.999 0.999	Water-expansion drive
Strong-water drive	0.950 0.935 0.929	23386.9 46773.8 70160.7	6.7114 13.2127 19.6407	1.013 0.984 0.926	0.972 0.920 0.860	Strong-water drive
Compressible reservoir ($q_g = 10$ % of original gas in place volume per year)						
Gas drive	0.946 0.891 0.836	23386.9 46773.8 70160.7	6.7320 13.0609 18.9542	1.031 1.067 1.109	1.000 1.000 1.000	Gas drive
Water-expansion drive	0.958 0.907 0.852	23386.9 46773.8 70160.7	6.7735 13.2123 19.2305	1.009 1.036 1.073	0.986 0.980 0.978	Water-expansion drive
Strong-water drive	0.964 0.942 0.927	23386.9 46773.8 70160.7	6.7831 13.3660 19.8138	0.998 0.971 0.927	0.978 0.940 0.889	Strong-water drive
Incompressible reservoir ($q_g = 20$ % of original gas in place volume per year)						
Gas drive	0.833 0.695 0.580	46773.8 93547.6 140321.4	12.5785 22.8011 31.1853	1.200 1.439 1.723	1.000 1.000 1.000	Gas drive
Water-expansion drive	0.836 0.697 0.582	46773.8 93547.6 140321.4	12.6137 22.8643 31.2689	1.194 1.432 1.716	0.998 0.998 0.998	Water-expansion drive
Strong-water drive	0.890 0.863 0.844	46773.8 93547.6 140321.4	12.9761 25.0093 36.6500	1.005 0.973 0.851	0.946 0.840 0.719	Strong-water drive
Compressible reservoir ($q_g = 20$ % of original gas in place volume per year)						
Gas drive	0.891 0.781 0.675	46773.8 93547.6 140321.4	13.0608 24.4177 34.1555	1.06 1.157 1.275	1.000 1.000 1.000	Gas drive
Water-expansion drive	0.916 0.816 0.715	46773.8 93547.6 140321.4	13.2402 26.0804 35.3748	1.020 1.968 1.140	0.970 0.949 0.930	Water-expansion drive
Strong-water drive	0.925 0.869 0.822	46773.8 93547.6 140321.4	13.2744 25.5838 37.0993	1.000 0.957 0.885	0.958 0.884 0.790	Strong-water drive

As seen in the data shown in Table 1, there is a relation between the parameters of $\bar{\Omega}_p$, $\bar{\Omega}_m$ and the actual reservoir drive. So, it is evident that under water-expansion and gas drives, $\bar{\Omega}_p$ is always more than unity, whereas in strong-water drive it is less than unity. It is also seen that this effect does not depend on the production rate and formation compaction factor and can be observed at any stage of development. It is also interesting that $\bar{\Omega}_m$ becomes equal to unity in the gas drive, while it is always less than unity in the water drives. One can understand that considering that in the gas drive, i.e. when there is no water invasion into the reservoir, the pore volume reduction occurs only due to the compaction of the reservoir rocks and $\bar{\Omega}_m$ is always equal to $\bar{\phi}$. One can easily see this by considering equations (18) and (19) together, given that $\bar{\Omega} = \frac{\Omega}{\Omega_0}$.

The results shown in Table 1 are graphically illustrated in Figures 3–6.

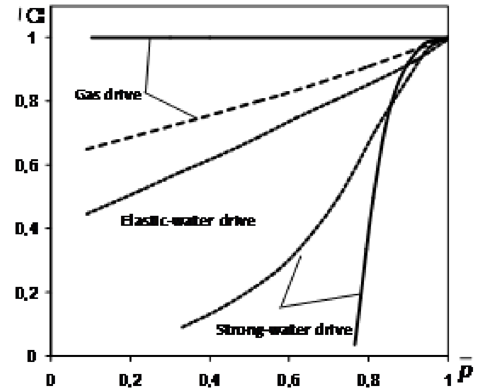

Figure 3. $\bar{\Omega}$ vs. $\bar{p}$ curves for various drive mechanisms. dotted line - compressible reservoir, continuous line - incompressible reservoir.

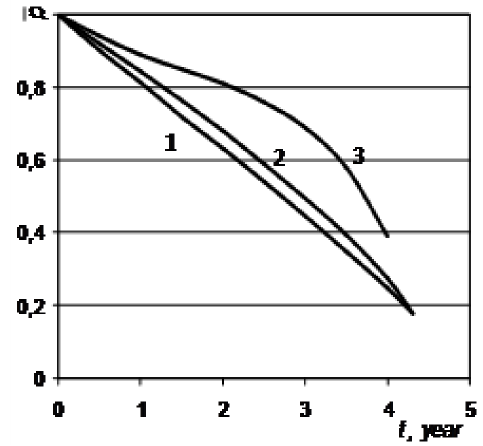

Figure 4. Reservoir pressure trends for various drive mechanisms.1- gas drive, 2-elastic -water drive, 3-strong-water drive.

It is seen from the $\Omega(\bar{p})$ curve in Figure 3 that $\bar{\Omega}$ has lower current values in case of a more active aquifer. At the beginning of development when there is a strong-water drive, the relatively high value of $\bar{\Omega}$ is related to the fact that the gas-water contact movement has not become active yet due to the incomplete reservoir pressure redistribution. This is also confirmed by the $\bar{p}(t)$ curves in Figure 4, which show that under strong-water drive condition, the reservoir pressure is higher, while the pore volume is lower (curves 3 and 2), whereas under the gas drive an adverse tendency (curve 1), i.e., relatively large pore volume and low reservoir pressure, is observed. This allows to characterize the reservoir drive mechanism, evaluate the aquifer productivity index and identify the reservoir drive.

To test this hypothesis, the $\bar{\Omega}_p(\bar{p})$ function has been studied in different reservoir drives and gas production rates for the compressible and non-compressible formations. The results are shown in Figure 5. It can be seen that the resulting curves are of two distinct types: the ones that increase by the decrease of dimensionless reservoir pressure ($\bar{p}$) starting from unity and the ones that decrease. This effect does not depend on the compaction of the formation and gas production rate.

The curves of the first type are characteristic for the cases where the pore volume reduction occurs primarily due to the formation compressibility and the fluids are moved by the elastic reserve of the reservoir system which contains formation compaction and reservoir fluid elasticity.

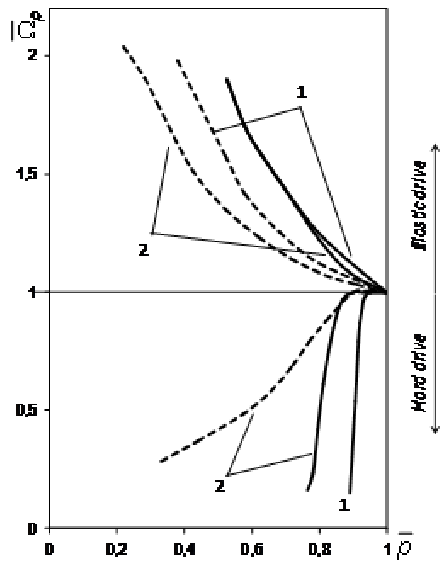

Figure 5. $\bar{\Omega}$ vs. $\bar{p}$ curves for various drive mechanisms. 1- gas drive, 2-elastic -water drive, 3- strong-water drive.

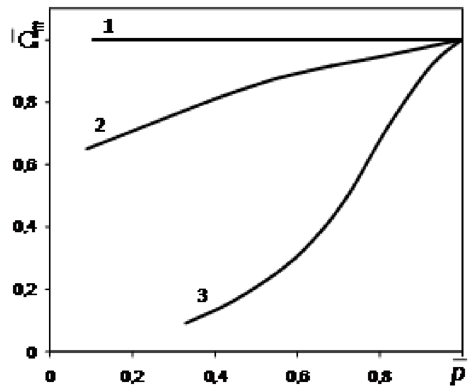

Figure 6. $\bar{\Omega}$ vs. $\bar{p}$ curves for various drive mechanisms. 1- gas drive, 2-elastic -water drive, 3- strong-water drive.

Such reservoir systems are characterized by a more intensive decrease in relative reservoir pressure ($\bar{p} = \frac{p}{p_0}$) that exceeds the reduction in the relative pore volume ($\bar{\Omega} = \frac{\Omega}{\Omega_0}$). This, in turn, leads to a sharp increase in $\bar{\Omega}_p$ the parameter in all possible cases. Thus, one can conclude that in elastic drive conditions the $\bar{\Omega}_p(\bar{p})$ function has a positive trend and its value is greater than unity at any moment of development. This effect allows characterizing the aquifer productivity and determining the reservoir drive. To do this, we just need to calculate and compare the value of $\bar{\Omega}_p$ with unity at the given reservoir pressure. If $\bar{\Omega}_p > 1$, then the reservoir drive mechanism refers to an elastic system, otherwise, if $\bar{\Omega}_p < 1$, - the reservoir refers to a hard system. However, in case of $\bar{\Omega}_p > 1$, only this parameter is not sufficient to identify the reservoir drive mechanism. Then it is necessary to differentiate the reservoir drive mechanism between the water-expansion and depletion (i.e. gas, solution-gas and other drives) systems. For this purpose, it is necessary to consider the $\bar{\Omega}_m$ parameter.

Figure 6 presents the curves of the $\bar{\Omega}_m(\bar{p})$ function. It is seen that in the gas drive (i.e. depletion), $\bar{\Omega}_m$ remains unchanged, while in the at water-expansion drive it reduces.

These results show that if the $\bar{\Omega}_m(\bar{p})$ parameter is less than unity, the reservoir development is accompanied by the influx of water into a reservoir. The current aquifer performance index can be evaluated by using the value of $\bar{\Omega}_m(\bar{p})$. The aquifer performance trend may be determined by the shape of the $\bar{\Omega}_m(\bar{p})$ curve. However, the constancy of $\bar{\Omega}_m(\bar{p})$ indicates that the aquifer does not exist or has a very low activity index.

The $\bar{\Omega}_m(\bar{p})$ and $\bar{\Omega}_p(\bar{p})$ parameters, in fact, are the indicators of the aquifer activity. So, they characterize the drive mechanism and can evaluate the performance of aquifer. We will call the $\bar{\Omega}_m(\bar{p})$ and $\bar{\Omega}_p(\bar{p})$ parameters as Reservoir Drive Performance Indexes (RDPI).

Summarizing the above-mentioned results, Table 2 has been created to determine the reservoir drive by RDPI.

Now the task is to obtain expressions for the determination of RDPI on the basis of production data. Below, a solution to this problem is discussed and the expressions are presented for calculating the values of RDPI for the gas-condensate and volatile oil reservoirs.

Table 2. Relation between RDPI and drive mechanisms.

$\bar{\Omega}_p$	$\bar{\Omega}_m$	Reservoir drive mechanisms
>1	=1	Gas drive
>1	<1	Water-expansion drive
<1	<1	Strong-water drive

3. The technique for determining RDPI for gas-condensate and volatile oil reservoirs

For the settlement of the problem the equations of material balances were used. The material balance equations for a gas-condensate system can be written as follows taking into account the rocks compaction [2]:

$$q_g = -\frac{d}{dt}\left[\frac{(1-s)p\beta}{z(p)p_{at}}[1-c(p)\bar{\gamma}(p)] + \frac{sS(p)}{B(p)}\right]\Omega(p,t) \tag{20}$$

$$q_c = -\frac{d}{dt}\left[\frac{s}{B(p)} + (1-s)\frac{p\beta c(p)}{z(p)p_{at}}\right]\Omega(p,t) \tag{21}$$

where $\bar{\gamma}$ is the ratio of the specific weights of heavy hydrocarbons in vaporous and liquid states;

The material balance equations for a volatile oil are written as follows [1]:

$$q_o = -\frac{d}{dt}\left[\frac{s_o}{Bo(p)} + (1-s_o)\frac{p\beta C_o(p)}{z(p)p_{at}}\right]\Omega(p,t) \tag{22}$$

$$q_g = -\frac{d}{dt}\left[\frac{(1-s_o)p\beta}{z(p)p_{at}}[1-c(p)\bar{\gamma}_o] + \frac{s_oS(p)}{B_o(p)}\right]\Omega(p,t) \tag{23}$$

where Ω is the volume of gas- or oil-saturated (depending on the case to be considered) pores. The rest of the designations are the same as in the above equations.

Determination of RDPI for gas-condensate reservoirs. Let us first consider the case of a gas-condensate reservoir. Suppose that the reservoir has been developed for t time. Within this time, the reservoir pressure has dropped to the value of p and the cumulative production of gas and condensate have become Q_g and Q_c.

Taking this into account, the following equation can be written using (20):

$$\int_0^t q_g dt = \int_{p_0}^{p} d\left[\frac{(1-s)p\beta}{z(p)p_{at}}[1-c(p)\bar{\gamma}] + \frac{sS(p)}{B(p)}\right]\Omega(p,t) \tag{24}$$

Assuming that the original reservoir pressure (p_0) is higher than the dew point pressure and accordingly, initial condensate-saturation (s_0) is zero, the equation (24) can be rewritten as follows:

$$\bar{Q}_g = \alpha_0 - (1-s)\alpha_p\bar{\Omega} - s\frac{S(p)}{B(p)}\bar{\Omega}, \tag{25}$$

where $\bar{Q}_g = \frac{Q_g}{\Omega_0}$; Ω_0 is the original volume of reservoir pores; $\bar{\Omega} = \frac{\Omega}{\Omega_0}$; $\alpha_p = \frac{p\beta}{z(p)p_{at}}[1 - c(p)\bar{\gamma}(p)]$; $\alpha_0 = \frac{p_0\beta}{z_0 p_{at}}[1-c_0\bar{\gamma}_0]$; p, p_0- current and original reservoir pressure respectively. The other parameters with zero indexes correspond to an initial reservoir pressure.

By integrating equation (21) within the same time and pressure bounds for determination of the condensate saturation, one can obtain the following expression:

$$s = \frac{\bar{Q}_c - \alpha_0^* + \alpha_p^*\bar{\Omega}}{\left(\alpha_p^* - \frac{1}{B(p)}\right)\bar{\Omega}}, \tag{26}$$

where $\alpha_0^* = \frac{p_0\beta c_0}{z_0 p_{at}}$, $\alpha_p^* = \frac{p\beta c(p)}{z(p)p_{at}}$; $\bar{Q}_c = \frac{Q_c}{\Omega_0}$.

By combining equations (24) and (25) the next expression for determination of $\bar{\Omega}$ can be obtained:

$$\bar{\Omega} = \frac{\frac{\bar{Q}_g - \alpha_0}{\alpha_p - \frac{S(p)}{B(p)}} - \frac{\bar{Q}_c - \alpha_0^*}{\alpha_p^* - \frac{1}{B(p)}}}{\frac{\alpha_p^*}{\alpha_p^* - \frac{1}{B(p)}} - \frac{\alpha_p}{\alpha_p - \frac{S(p)}{B(p)}}} \tag{27}$$

By multiplying both sides of equation (26) by $\frac{p_0}{p}$ an expression for calculating the parameter of $\bar{\Omega}_p$ can be obtained as follows:

$$\bar{\Omega}_p = \frac{\frac{\bar{Q}_g - \alpha_0}{\alpha_p - \frac{S(p)}{B(p)}} - \frac{\bar{Q}_c - \alpha_0^*}{\alpha_p^* - \frac{1}{B(p)}}}{\frac{\alpha_p^*}{\alpha_p^* - \frac{1}{B(p)}} - \frac{\alpha_p}{\alpha_p - \frac{S(p)}{B(p)}}} \cdot \frac{p_0}{p} \tag{28}$$

Given the designation $\bar{\Omega}_m = \frac{\bar{\Omega}}{\phi}$, an expression for $\bar{\Omega}_m$ can be obtained from (26) as in (27):

$$\bar{\Omega}_m = \frac{\frac{\bar{Q}_g - \alpha_0}{\alpha_p - \frac{S(p)}{B(p)}} - \frac{\bar{Q}_c - \alpha_0^*}{\alpha_p^* - \frac{1}{B(p)}}}{\frac{\alpha_p^*}{\alpha_p^* - \frac{1}{B(p)}} - \frac{\alpha_p}{\alpha_p - \frac{S(p)}{B(p)}}} \cdot \frac{1}{e^{c_m(p-p_0)}} \tag{29}$$

Determination of RDPI for volatile oil reservoirs. The expressions for evaluation of RDPI of light oil reservoirs can be obtained analogously to the gas-condensate case using the material balance equations for oil and gas (22) and (23) as follows:

$$\bar{\Omega}_p = \frac{\frac{\bar{Q}_g - \alpha_0}{\alpha_p - \frac{S(p)}{B_o(p)}} - \frac{\bar{Q}_o - \frac{1}{B_o(p_0)}}{\alpha_p^* - \frac{1}{B_o(p)}}}{\frac{\alpha_p^*}{\alpha_p^* - B_o(p)} - \frac{\alpha_p}{\alpha_p - \frac{S(p)}{B_o(p)}}} \cdot \frac{p_0}{p} \tag{30}$$

$$\bar{\Omega}_m = \frac{\frac{\bar{Q}_g-\alpha_0}{\alpha_p-\frac{S(p)}{B_o(p)}} - \frac{\bar{Q}_o-\frac{1}{B_o(p_0)}}{\alpha_p^*-\frac{1}{B_o(p)}}}{\frac{\alpha_p^*}{\alpha_p^*-B_o(p)} - \frac{\alpha_p}{\alpha_p-\frac{S(p)}{B_o(p)}}} \cdot \frac{1}{e^{c_m(p-p_0)}} \tag{31}$$

where Q_o is the cumulative production of oil,

$$\bar{Q}_o = \frac{Q_o}{\Omega_0}; \quad \alpha_p = \frac{p\beta}{z(p)p_{at}}[1 - C_o(p)\bar{\gamma}_o(p)], \quad \alpha_p^* = \frac{p\beta C_o(p)}{z(p)p_{at}}$$

The expressions (29) and (30) for black-oil reservoirs are applied with the following parameters: $\alpha_p = \frac{p\beta}{z(p)p_{at}}$ and $\alpha_p^* = 0$.

By using equations (27) and (28), or (29) and (30), it is possible to determine the main source of reservoir energy, i.e., to define the type of reservoir-drive mechanism in gas-condensate and volatile oil reservoirs. For this, one needs to know the value of cumulative production of fluids and the value of reservoir pressure at a given time point in the development process. And a reservoir-drive is determined from Table 2 by using the values of RDPI calculated by the equations (27) and (28), or (29) and (30).

4. Approbation and conclusions

In order to evaluate the reliability of the proposed approach and illustrate the relevance of the obtained equations, a number of model calculations have been performed. So, the process of development of a gas condensate reservoir with a known initial pore volume has been simulated in case of absence of an active aquifer with the gas production rate equal to 5 % of original gas in place volume per year. The compressible (the formation compaction factor $c_m = 0.01\ MPa^{-1}$) and non-compressible reservoirs have been considered. The reservoir pressure trend and the values of cumulative production for the considered cases were found out and then by using these results as field historical data the values of $\bar{\Omega}$ have been calculated by (26).

The comparison between the calculated and actual values of $\bar{\Omega}$ at various reservoir pressures is shown in Table 3. The maximum deviation of $\bar{\Omega}$ from its actual value corresponds to $\bar{p}$ =0.05 but does not exceed 1.1%.

The proposed approach was also tested for the actual reservoirs by using the expressions (27) and (28). The 9^{th} horizon of the Bahar field and the 10^{th} horizon of the Cenub field (Azerbaijan) with initial reservoir pressures of 45.4 and 35.8 MPa have been chosen as an example. Both of them are offshore gas-condensate fields and have been operated since 1971 and 1976 respectively. The mentioned reservoirs are at the final stage of development. So, there is full information about these reservoirs. Therefore, it is possible to compare the results of the proposed method.

On the basis of production data corresponding to the moment when the reservoir pressure was equal to 18.5 MPa the values of RDPI were calculated for the 9th horizon of the Bahar field. Their values turned out as follows:

$\bar{\Omega}_p = 2.443303$ and $\bar{\Omega}_m = 0.998301$.

According to the data of Table 2, the obtained values of RDPI confirm the water-expansion drive, which was adopted in the development design of field at considered moment.

The values of RDPI for the 10^{th} horizon of the Cenub field were calculated at 3.40 MPa reservoir pressure and were equal to the following values:

$\bar{\Omega}_p = 0.943036$ and $\bar{\Omega}_m = 0.037211$. With this in mind by using Table 2 it can be concluded that a reservoir drive mechanism is a strong-water drive.

The tests showed that the proposed new indicators in this paper called RDPI can evaluate the aquifer performance effectively. The technique developed on the base of RDPI to determine the reservoir drive mechanism in gas-condensate and oil fields have a high level of reliability.

Table 3. Comparison of the calculated and actual values of for various reservoir pressures.

$\bar{p}$	Calculated $\bar{\Omega}$	Actual $\bar{\Omega}$	Deviation , %
Incompressible reservoir			
1.00	1.00000	1.00000	-
0.83	1.00012	1.00000	0.01
0.69	1.00026	1.00000	0.03
0.58	1.00041	1.00000	0.04
0.47	1.00061	1.00000	0.06
0.38	1.00086	1.00000	0.09
0.28	1.00122	1.00000	0.12
0.19	1.00184	1.00000	0.18
0.10	1.00350	1.00000	0.35
0.05	1.00666	1.00000	0.67
Compressible reservoir			
1.00	1.00000	1.00000	-
0.96	0.96772	0.96770	0.00
0.87	0.90460	0.90452	0.01
0.79	0.84344	0.84330	0.02
0.70	0.78413	0.78391	0.03
0.60	0.72633	0.72601	0.04
0.50	0.66941	0.66896	0.07
0.39	0.61237	0.61172	0.11
0.26	0.55348	0.55244	0.19
0.10	0.48983	0.48715	0.55
0.05	0.47388	0.46885	1.07

5. Nomenclature

r= polar coordinate, m; q_g= gas production rate, m^3/s, q_c= condensate production rate, m^3/s; q_o= oil production rate, m^3/s, p= reservoir pressure, MPa, k= absolute permeability, m^2, m= current porosity of reservoir, m_o= initial porosity of reservoir, s= condensate saturation, $k_c(s)$= relative permeability of condensate, $k_g(s)$= relative permeability of gas phase, μ_c= dynamic viscosity of condensate, $MPa{\cdot}s$, μ_g= dynamic viscosity of gas-phase, $MPa{\cdot}s$, B = volume factor of liquid condensate, S= gas solubility in liquid-phase, m^3/m^3, z= gas compressibility factor, β= gas temperature-correction factor, c= concentration of the potentially liquid heavy components of gas-phase, p_{atm}= atmospheric pressure, MPa, t= time, s, c_m= formation compaction factor, MPa^{-1}, R_b= boundary radius, m, r_w= well radius, m, h= formation thickness, m.

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