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Identification of gas reservoirs and determination of their parameters by combination of radioactive logging methods

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Запропоновано новий підхід до використання комплексу радіоактивного каротажу — нейтрон-нейтронного (ННК) і гамма-гамма каротажу (ГГК), який дозволяє визначати сукупність параметрів газових колекторів (характер насичення, істинна пористість, коефіцієнт газонасиченості) з урахуванням впливу термобаричних умов залягання. Виконано аналіз варіантів усереднення позірних пористостей за ННК і за ГГК при отриманні істинної пористості. Розроблено спосіб визначення коефіцієнта газонасиченості, який використовує той же комплекс, що й при визначенні істинної пористості газових колекторів. Приведені результати отримано для широкого інтервалу глибин (до 10 км). Застосування розвинутих підходів до визначення петрофізичних параметрів газових колекторів продемонстровано на прикладі обсадженої метановугільної свердловини.

Ключові слова: газові пласти-колектори, термобаричні умови залягання, комплекс нейтрон-нейтронного і гамма-гамма каротажу, виділення газових пластів-колекторів, позірні пористості, істинна пористість, коефіцієнт газонасиченості.

1. Introduction. The subject of investigation is a gas reservoir in open and cased wells taking into account the pressure and temperature conditions of occurrence (*PT*-conditions).

Porosity, gas saturation and permeability are the main petrophysical parameters of gas reservoirs. Important parameters are also bulk density of the rock; weight and volume fraction of shale and clay minerals; hydrogen indices of rock, shales, clay minerals and interstitial fluids [Interpretation…, 1988].

Radioactive logging methods are universal methods for determination of parameters of conventional and unconventional gas reservoirs in both open and cased holes. The density logging (for determination of the bulk density), neutron logging (for determination of the neutron porosity) and gamma ray logging (as neutron logging correction for the hydrogen content in clay minerals) are effective enough methods for obtaining the majority of petrophysical parameters of reservoirs [Golovatskaia et al., 1984; Serra, 1984; Nuclear..., 1990; Ellis, Singer, 2008].

Features of the application of these radioactive logging methods (density logging, neutron logging and gamma ray logging) for investigation of gas reservoirs are considered in [Alger, Dewal, 1969; Golovatskaia et al., 1984; DasGupta, 1997; Mao, 2012; Ijasan et al., 2013]. In particular, neutron logging or density logging separately do not allow determining the true porosity and other parameters of the gas reservoirs. The solution of this problem requires their combined use [Kulyk, Bondarenko, 2013a, b; Bondarenko et al., 2014].

At the same time, the existing approaches of combined use of neutron logging and density logging have shortcomings and restrictions. Among these are absence of substantiation of an optimal method of averaging the neutron-apparent and density-apparent porosities for determining true porosity of gas reservoir, neglect of occurrence depth, necessity to use the electric logging for determining gas saturation (by means of water saturation) and others.

The paper proposes a new approach of using radioactive logging combination, which allows determining set of the gas reservoir parameters (nature of saturation, true porosity and gas saturation) taking into account influence of pressure and temperature conditions of gas reservoir occurrence. Results presented in the paper were obtained for a wide depth interval (up to 10 km). The application of developed approaches to determine petrophysical parameters of gas reservoirs has been demonstrated by the example of cased coal-bed methane well.

2. Features of radioactive logging in both open and cased holes. Investigation of reservoirs in both open and cased wells has its own features.

2.1. Open hole. After drilling, the near-wellbore region of gas reservoir can have properties, different from a virgin bed.

When drilling on water-based mud in *conventional reservoirs* the invaded zone is formed.

The problem of determining true porosity in the presence of invaded zone under certain conditions can be solved, as shown in [DasGupta, 1997], with the help of combination of density-neutron loggings. However, this paper disregards the influence of residual gas saturation, which mostly is equal about 20 % [Hallenburg, 1998].

Residual gas essentially influences on the readings of radioactive logging tools and, hence, on porosities determined by density-neutron loggings. In actual practice, when the invasion depth exceeds the depth of investigation of density-neutron loggings, identification of gas reservoirs and determination of their true porosity on the basis of the combination of radioactive loggings are possible, as well as a quantitative estimation of residual gas saturation [Kulyk et al., 2014].

When drilling on oil-based mud the invaded zone practically is not formed [Cholet, 2000]. Invasion is also a minimal when logging while drilling. It is absent also in gas-saturated tight sandstones and gas-saturated shales because of low permeability (*unconventional reservoirs*). In these cases, combination of radioactive loggings, under certain conditions, allows to determine the true petrophysical parameters of gas reservoir.

2.2. Cased hole. The investigation of conventional gas reservoirs in cased holes has become an increasingly important. This is due to following problems: old wells reevaluation, control over gas-saturation in the course of gas reservoir development, monitoring of wells of underground gas storages, necessity of immediate casing the holes (for example, when drilling in the complicated geological conditions). The latter takes place in Ukraine, in particular, during both exploration of hydrocarbons at great depths (over 6 km) and investigation of coal-bed methane wells.

After drilling and casing the holes, the mud filtrate dissipates during the time from a few weeks [Serra, 1984] to a few months and even to a few years, depending on the reservoir properties. In immediately cased wells invaded zone mostly has no time to form or this zone is negligible. The invaded zone is absent in old wells.

Radioactive logging is practically without alternative in the cased holes for identification gas-bearing reservoirs, for determination of their porosity, gas saturation and other parameters.

3. Pressure and temperature conditions. Estimation of *PT*-conditions influence in determining the parameters of gas reservoirs is the topical task due to the facts that the depth of commercial gas production increases and the reservoirs with abnormally high formation pressure (AHFP) exist.

At the present time the gas presence of formations at great depths (up to about 10 km) is proved [Reeves et al., 1998; Thaddeus, Cook, 2001; Lukin, 2014b]. Total porosity as a whole declines with the depth, whereas the gas density and the amount of hydrogen per unit volume increase. In other words, hydrogen index of a gas increases with increasing formation pressure. Accordingly, *PT*-conditions significantly affect the radioactive logging tools readings, measured neutron and density porosities and other parameters.

Formation pressure is the pressure of the fluids (formation water, oil, gas) in the pore space of the formation. It is generally accepted that normal formation pressure is equal to hydrostatic pressure. The hydrostatic pressure is caused by the water column which has a certain density and is extending from the wellhead to the investigated formation. Conditional hydrostatic pressure (CHP) is equal to the pressure of the column of water with density of 1 g/cm^3. Pressure gradient which corresponds to conditional hydrostatic pressure is equal to 10 MPa/km [Fertl et al., 1976; Melik-Pashaev et al., 1983; Chilingar et al., 2002].

Manifestations of AHFP in gas reservoirs lying at different depths are recorded practically in all regions of the world. For the reservoir, which is located at a given depth, the lower limit of AHFP is determined by the density of formation water at a maximal salinity (~1.3 g/cm^3). The upper limit of AHFP corresponds to overburden pressure which produces formation with an average bulk density ~2.3 g/cm^3. Thus, the pressure gradient corresponding to AHFP lies in the range about ~13—23 MPa/km [Fertl et al., 1976; Melik-Pashaev et al., 1983; Chilingar et al., 2002].

The average geothermal gradient in most of oil and gas fields is equal to ~30 °C/km [Petrenko et al., 2004; William, Plisga, 2005], while pressure gradient corresponds to CHP [Petrenko et al., 2004].

Gas density and hydrogen index of gas with consideration of *PT*-conditions were obtained below on a basis of real gas equation of state with compressibility factor to account for non-ideal behavior of real gas [Reid et al., 1977]. Most of the parameter calculations were obtained for the CHP and average geothermal gradient.

4. Petrophysical model. For investigation of principal aspects of determination of both the porosity and the gas saturation we accepted the following simplest petrophysical model of reservoir.

By «gas reservoir» we shall mean rock, which contains free gas in open, closed pores or in both.

Solid constituent of the rock (matrix) consists of single mineral (quartz, calcite, dolomite), excluding shale. Pores are filled with fresh water and gas (methane CH_4) in various proportions. The relative volume of gas in the pores of a rock is the gas saturation. Gas saturation vary from 0 (water) to 1 (total gas saturation).

Matrix density and density of interstitial water are accepted as constant in the depth interval from 0 to 10 km; *PT*-conditions of gas reservoir occurrence determine gas density.

5. Apparent porosities of gas reservoirs. ***5.1. Neutron porosity.*** Neutron porosity is closely related to the hydrogen content in the rock. It is necessary to construct a calibration curve for determination of neutron porosity φ_N. This calibration curve is a relation between readings of neutron tool and porosity of water-filled pure rock (for example, non-shale limestone) for the given technical conditions of measurement.

Gas reservoir has a lower number of hydrogen nuclei in unit volume than a water-filled formation of the same porosity. When gas-filled formation is logged, the neutron porosity φ_N, which is estimated using the «water-filled» calibration curve, will be apparent. This apparent porosity will be lower than the true porosity.

The relative hydrogen content (hydrogen index, ω) of porous gas-water-filled non-shale formation in terms of hydrogen indices of water ω_w and gas ω_g is written as [Serra, 1984]:

$$\omega = \omega_w \varphi (1 - S_g) + \omega_g \varphi S_g \,, \qquad (1)$$

where φ is the porosity of gas reservoir; S_g is the gas saturation; ω_w is the hydrogen index of water (hydrogen index of fresh water ω_w=1); ω_g is the hydrogen index of gas; the hydrogen index of methane is given by:

$$\omega_g = 2{,}25 \rho_g / \rho_w \,, \qquad (2)$$

where ρ_g is the gas density in the pores for the given pressure-temperature conditions, ρ_w is the water density.

As a first approximation the hydrogen index of a water-filled reservoir is equal to neutron porosity. The hydrogen index of a gas-filled formation can be approximately considered as the neutron-apparent porosity, i. e. $\omega \approx \varphi_N$. Then, from the Eq. (1) it follows that

$$\varphi_N = \varphi - \Delta\varphi_N \,, \qquad (3)$$

where

$$\Delta\varphi_N = (\omega_w - \omega_g)\varphi S_g \,. \qquad (4)$$

According to Eq. (3), neutron-apparent porosity of gas reservoirs will be lower than the true porosity on the value $\Delta\varphi_N$. In the case of a fully water-saturated reservoir (S_g=0, $\Delta\varphi_N$=0), neutron-apparent porosity becomes true: $\varphi_N = \varphi$. In the case of a fully gas-saturated reservoir (S_g=1), neutron-apparent porosity takes a minimum value: $\varphi_N = \omega_g \varphi$.

5.2. Density porosity. The results of density logging are due to electron density of rock, which, in turn, is closely connected with bulk density. The total porosity of water-saturated reservoirs obtained from the density logging is expressed as:

$$\varphi_D = \frac{\rho_s - \rho^{\gamma\gamma}}{\rho_s - \rho_w} \,, \qquad (5)$$

where ρ_s is the bulk density of solid component, ρ_w is the water density, $\rho^{\gamma\gamma}$ is gamma-gamma log density [Serra, 1984; Interpretation…, 1988; Ellis, Singer, 2008].

The bulk density of gas-water-saturated reservoirs ρ is determined using the following equation:

$$\rho = \rho_s(1 - \varphi) + \rho_w \varphi (1 - S_g) + \rho_g \varphi S_g \,. \qquad (6)$$

Taking into account that $\rho^{\gamma\gamma} \approx \rho$, and substituting Eq. (6) in Eq. (5), we get expression for the density-apparent porosity of gas-water-saturated reservoirs:

$$\varphi_D = \varphi + \Delta\varphi_D \,, \qquad (7)$$

where

$$\Delta\varphi_D = (\Delta_g - 1)\varphi S_g \,. \qquad (8)$$

Here Δ_g is dimensionless density parameter (Δ_g>1), which at given ρ_s=const and ρ_w=const is determined by the gas density ρ_g under reservoir conditions:

$$\Delta_g = \frac{\rho_s - \rho_g}{\rho_s - \rho_w} \,. \qquad (9)$$

According to Eq. (7), density-apparent porosity of the gas reservoirs is higher than the true porosity on the value of $\Delta\varphi_D$. In the case of a fully water-saturated reservoir, density-apparent porosity becomes true: φ_D=φ. In the case of a fully gas-saturated reservoir, density-apparent porosity takes a maximum value: $\varphi_D=\Delta_g\varphi$.

5.3. Relation between apparent porosities and true porosity. Three different porosities (neutron-apparent porosity, density-apparent porosity and true porosity) are used in the investigation of gas reservoirs with the aid of radioactive logging combination.

As an example of gas-saturated sandstones at 20 %-porosity and 10 %-porosity, the results of estimating the neutron-apparent porosity and density-apparent porosity on the basis of Eqs. (3), (4) and Eqs. (7)—(9), respectively, for various gas saturations depending on the occurrence depth are shown in Fig. 1.

Fig. 1 shows that depth-dependences of the apparent porosities φ_N and φ_D are nonlinear, in so doing the nonlinearity increases with increasing S_g. For reservoirs deeper than ~4 km, porosities φ_N and φ_D relatively depend only weakly on the *PT*-conditions for all the values of S_g.

Thus, the differences between density-apparent porosity and true porosity, between neutron-apparent porosity and true porosity, between density-apparent porosity and neutron-apparent porosity are increasing as the gas saturation increases. The same pattern is characteristic for gas reservoir with increasing true porosity. The effect of gas on both density porosity and neutron porosity decreases with increasing depth at the expense of an increase in gas density and hydrogen index of gas. In so doing effect of gas saturation on the neutron logging is stronger than on the density logging over the whole depth interval and it doesn't depend on both gas saturation and true porosity.

We consider ratios of density-apparent porosity and neutron-apparent porosity to true porosity ($R_N=\varphi_N/\varphi$ and $R_D=\varphi_D/\varphi$), respectively, as:

$$R_N = 1-(\omega_w-\omega_g)\,S_g\,, \tag{10}$$

$$R_D = 1+(\Delta_g-1)\,S_g\,, \tag{11}$$

together with the ratio of neutron-apparent porosity to density-apparent porosity, $R_{N/D}=\varphi_N/\varphi_D$, as

$$R_{N/D} = \frac{1-(\omega_w-\omega_g)\,S_g}{1+(\Delta_g-1)\,S_g}\,. \tag{12}$$

Fig. 2 demonstrates depth dependences of the ratios R_N, R_D and $R_{N/D}$ for various gas saturations S_g.

Analysis of Eq. (10)—(12) along with Fig. 2 leads to the following conclusions:

• to accepted approximation the ratios R_N, R_D and $R_{N/D}$ are independent of porosity of gas reservoir, i. e., Eq. (10)—(12) and Fig. 2 are valid for any porosity;

• dependences of the ratios R_N, R_D and $R_{N/D}$ on the occurrence depth of beds h are nonlinear for any values of S_g; in so doing for small values

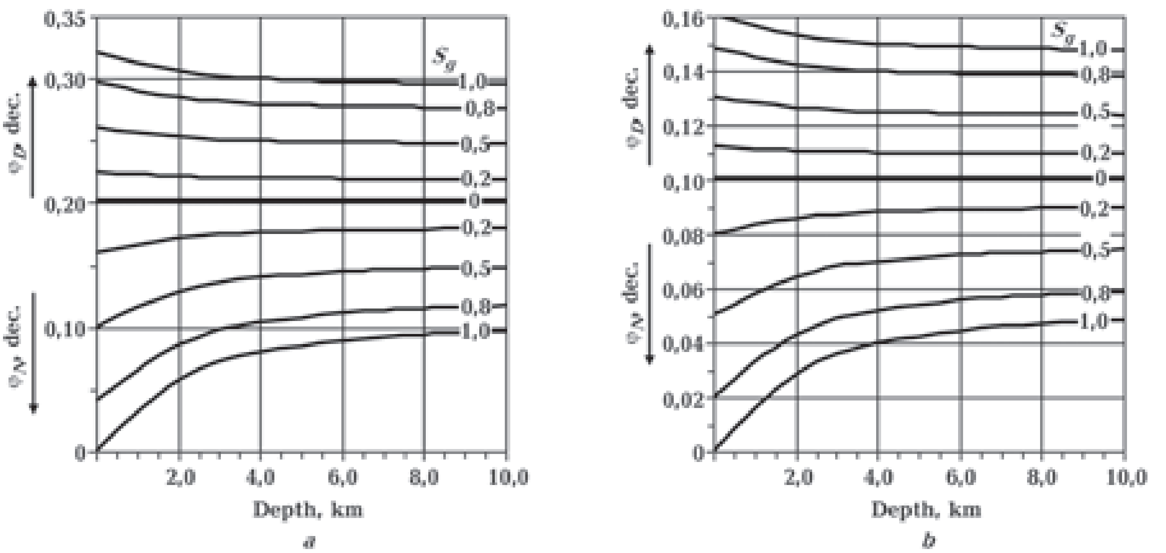

Fig. 1. Apparent porosities φ_N and φ_D of gas reservoirs vs depth for sandstone with φ=0.2 (*a*) and φ=0.1 (*b*) at different gas saturation.

S_g(<0.2) this nonlinearity is weak (R≈const(h)), whereas for large values S_g (>0.8) nonlinearity is relatively strong to a depth of ~4 km; at the bigger depths parameters R depend relatively only weakly on PT-conditions for all values of S_g;

- if S_g=0 (fully water-saturated pores) it is obvious that R_N=R_D=$R_{N/D}$=1; at S_g=1 (fully gas saturation) we may write that R_N=ω_g(<1), R_D=Δ_g(>1), $R_{N/D}$=ω_g/Δ_g(<1);
- for all the values of S_g and h the ranges of ratios R are as follows: $0<R_N\le 1$; $1\le R_D\le \Delta_g$ (maximum value $\Delta_g\le 1.6$ corresponds to shallow depth and to maximum gas saturation); $0<R_{N/D}\le 1$.

Thus, parameters R_N and R_D provide quantitative estimating for the ratio of both apparent porosities to true gas reservoir porosity as a functions of the occurrence depth at a given value of the gas saturation; whereas the parameter $R_{N/D}$ gives a quantitative relationship between apparent porosities depending on the same factors.

6. Identification of gas reservoirs. Estimation of nature of saturation (gas, water) is impossible using neutron logging or density logging separately, whereas their combined use solves this problem. One known way of solving the problem of gas reservoirs identification is to compare of neutron-apparent porosity and density-apparent porosity as borehole logs [Ellis, Singer, 2008].

Disagreement between density porosity and neutron porosity along geological section of borehole can serve as convenient quantitative criterion of gas-filled rocks. This disagreement is determined by difference of two porosities

$$\Delta\varphi = \varphi_D - \varphi_N . \tag{13}$$

Difference $\Delta\varphi$ can be considered as a parameter of gas reservoir identification. For water-saturated rocks, difference is zero ($\Delta\varphi$=0), whereas for gas-bearing interval, wherein both density porosity and neutron porosity are apparent, this parameter is a positive value, and $\Delta\varphi$ increases, as the porosity and gas volume in pores are increased.

For reliable identification of gas reservoir, difference $\Delta\varphi$ shall exceed the total error of porosity determination with the help of density logging and neutron logging. In our estimation the absolute total error of difference $\Delta\varphi$ in practice is less than about ±3 %.

In Fig. 3 the calculated depth dependences of the parameter $\Delta\varphi$ at various gas saturations are shown for the sandstone with porosity 20 % (it corresponds to a conventional, good-quality reservoir which occurs at a moderate depth) and 5 % (it corresponds to an unconventional reservoir or to a deep-seated conventional reservoir [Lukin, 2014a]). Dashed line indicates the accepted absolute error (3 %) of parameter $\Delta\varphi$ for fully water-saturated pores ($\Delta\varphi$=0); that is, identification of gas reservoir in the range of parameter $\Delta\varphi$ from 0 to 0.03 is impracticable through errors of measurements.

As may be seen from Fig. 3, *a*, at relatively high true porosity the neutron-density loggings allow to identify gas reservoirs practically over

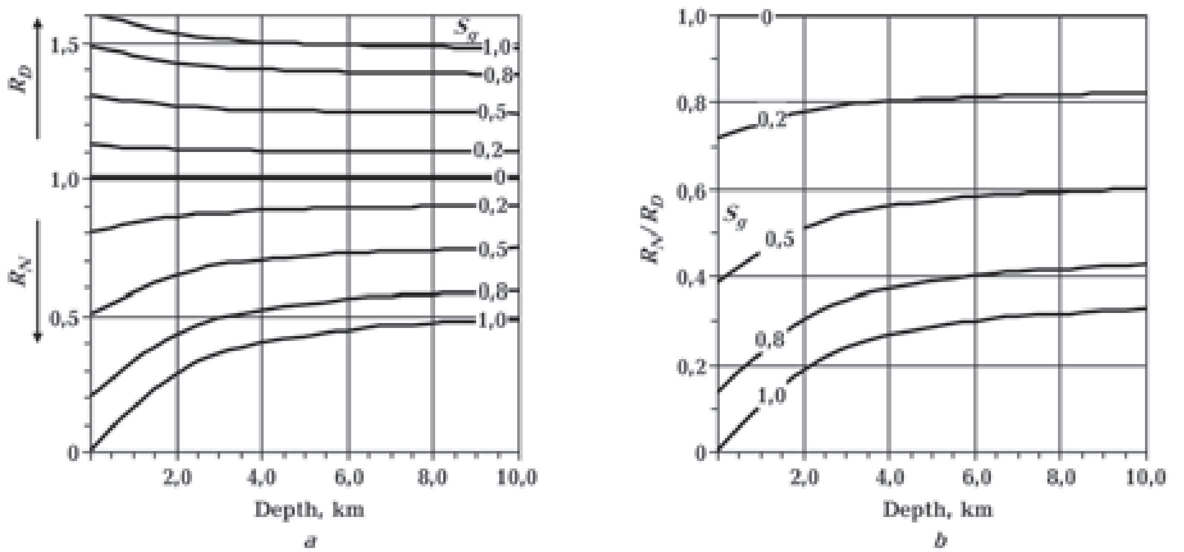

Fig. 2. Ratios R_D, R_N (*a*) and R_N/R_D (*b*) vs depth for sandstone at different gas saturation.

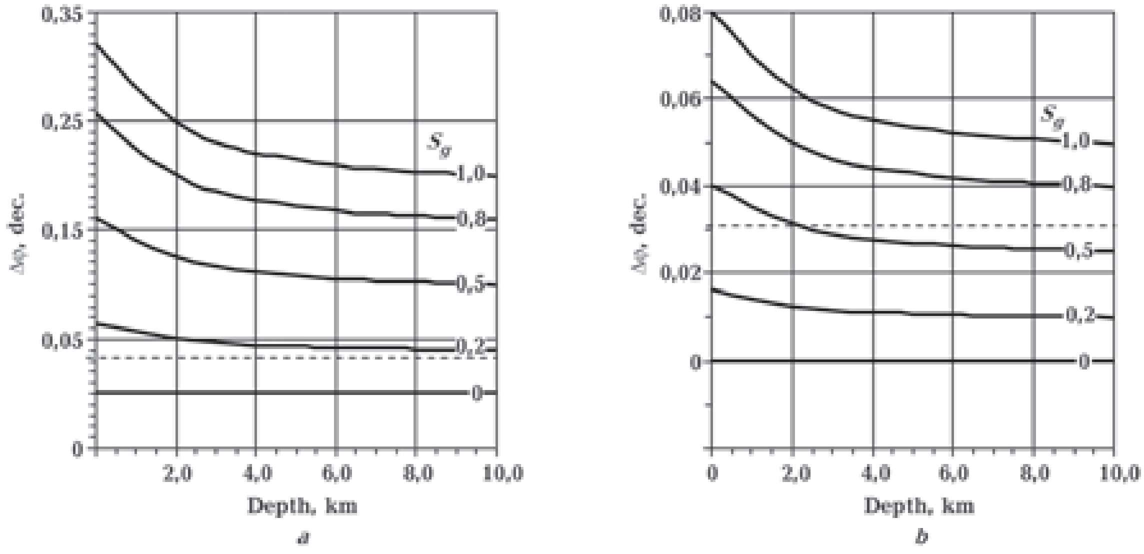

Fig. 3. Identification parameter Δφ vs depth for sandstone with φ=0.2 (*a*) and φ=0,05 (*b*) at different gas saturation. Dashed line shows error of identification parameter.

the whole gas saturation range (at S_g>0.2), in particular also in the presence of residual gas saturation in an invaded zone. From Fig. 3, *b* it follows that the neutron-density loggings allow to identify low-porosity gas reservoirs with confidence only at high gas saturation (at S_g>0.5—0.6). At low porosity the shallowness (less than ~2 km) of gas reservoir is favorable factor for its identification by neutron-density loggings.

Specific procedure of gas reservoirs identification consists in the following (see Fig. 4). Obtained neutron porosity log and density porosity log should be plotted together (at the same scale and use of the same porosity units). In gas reservoirs, the two porosity curves will cross over each other: the density porosity log will show higher porosity, while the neutron porosity log will show a lower porosity (φ_D>φ_N).

The magnitude of the crossover (the amount of separation between the curves) increases with increasing both true porosity and gas saturation. In water-saturation (non-shale) formations, the porosity curves obtained from neutron log and density log (φ_N and φ_D, respectively) are practically agreed (within the limits of errors).

Fig. 4 gives logging data obtained in immediately cased coal-bed methane well (Donbas, terrigenous geologic section). Gas reservoirs were identified by the use of difference Δφ in the following intervals (where the density porosity curve and neutron porosity curve are separated): X15—X20 m, X23—X30 m, X35—X40 m, X41—X50 m, X59—X65 m, X72—X75 m, X84—X90 m. Petrophysical parameters of gas reservoirs were also determined. In so doing, methods of determinations of true porosity φ and gas saturation S_g

Table 1. Example of determination of gas reservoir petrophysical parameters in the cased borehole

Number	Interval, m	φ_D, %	φ_N, %	Δφ, %	φ, %	S_g, %
1	X15—X20	17.5	11.4	6.1	15	26
2	X23—X26	19.8	13.4	6.4	18	24
3	X26—X30	22.2	3.1	19.1	16	80
4	X35—X40	19.1	13.3	5.8	17	22
5	X41—X47	21.8	14.8	7.0	19	24
6	X47—X50	15.5	9.6	5.9	13	29
7	X59—X62	19.6	13.0	6.6	17	25
8	X62—X65	23.0	5.4	17.6	17	68
9	X72—X75	17.9	8.1	9.8	14	44
10	X84—X90	17.3	10.2	7.1	15	31

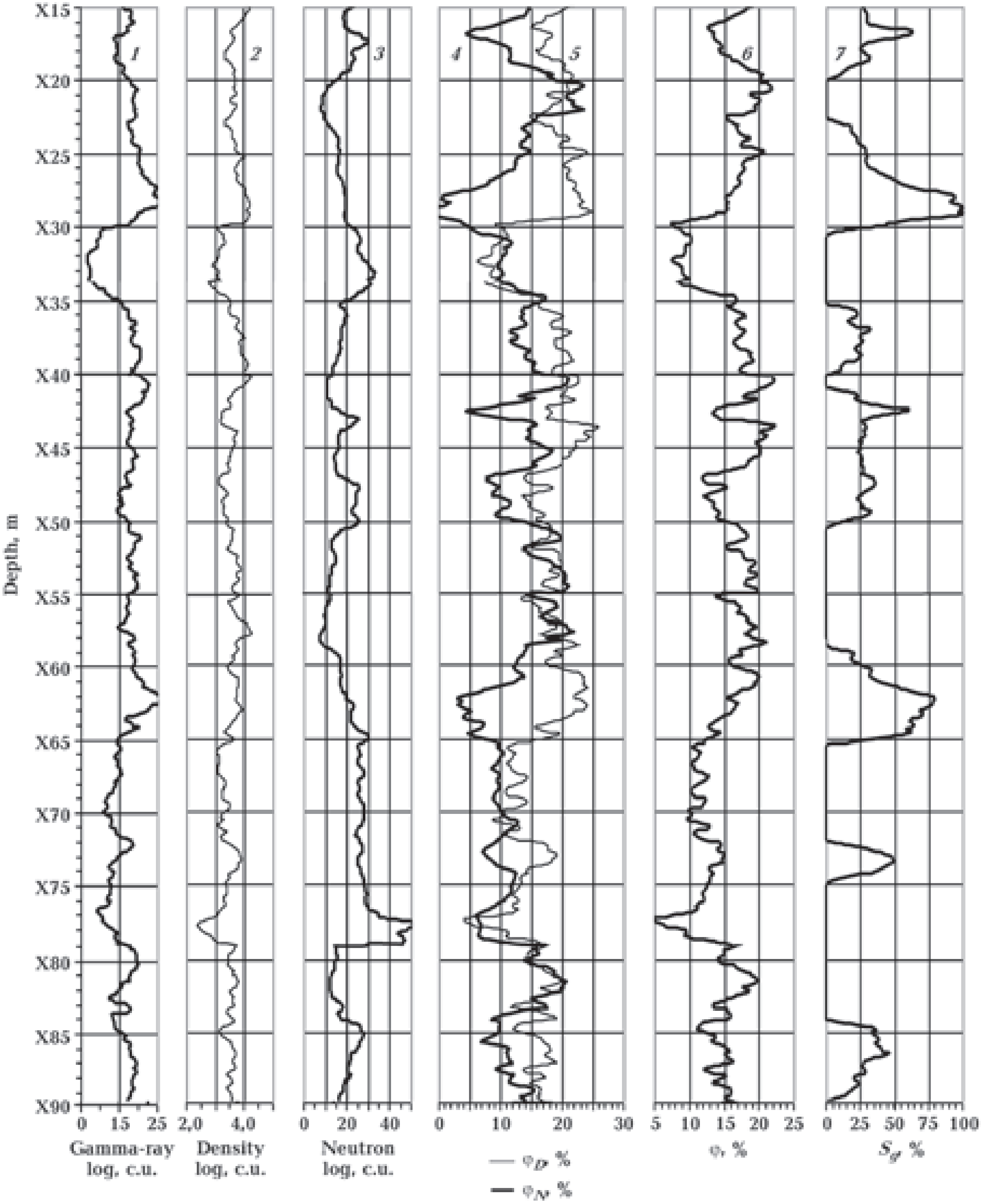

Fig. 4. Diagrams of radioactive logging (*1* — gamma-ray log, *2* — density log, *3* — neutron log; c. u. — conventional unit) and petrophysical parameters of formations (*4* — neutron porosity, *5* — density porosity, *6* — true porosity, *7* — gas saturation) obtained in coalbed methane well (Donbas, terrigenous geologic section).

will be considered in the following sections (see sections *7* and *8*).

The Tab. 1 gives, as an example, the results of determination of gas reservoir petrophysical parameters in the same borehole. Namely the following parameters are presented: apparent porosities φ_D and φ_N, parameter of gas reservoir identification $\Delta\varphi$, true porosity φ, gas saturation S_g.

Another known method exists for identification of gas reservoirs, namely, the comparison of neutron porosity and density porosity in the form of crossplot [Hunt, Pursell, 1997; Ellis, Singer, 2008].

Fig. 5 demonstrates the comparison of neutron porosity and density porosity for formations identified in aforementioned borehole. Diagonal line of crossplot represents the water-filled porosity, whereas water-saturated formations and low gas saturation formations fall within a dashed interval. Gas-saturated formations fall outside of dashed interval (the density porosity log shows higher porosity, while the neutron porosity log shows a lower porosity).

As may be seen from the crossplot, gas reservoirs are shifted up and to the left about the diagonal of this crossplot. This shift increases with increasing both true porosity and gas saturation.

A comparison between results of gas reservoirs identification by the use of neutron-density porosity logs plotted together (Fig. 4) and by the use of density-neutron crossplot method (Tab. 1 and Fig. 5), verified the efficiency of both. In practice it is expedient to use both approaches together.

7. True porosity of gas reservoirs from density-neutron loggings. ***7.1. Variants of averaging apparent porosities.*** In gas reservoirs, the neutron porosity is lower than the true porosity due to both low hydrogen content in the pore fluid

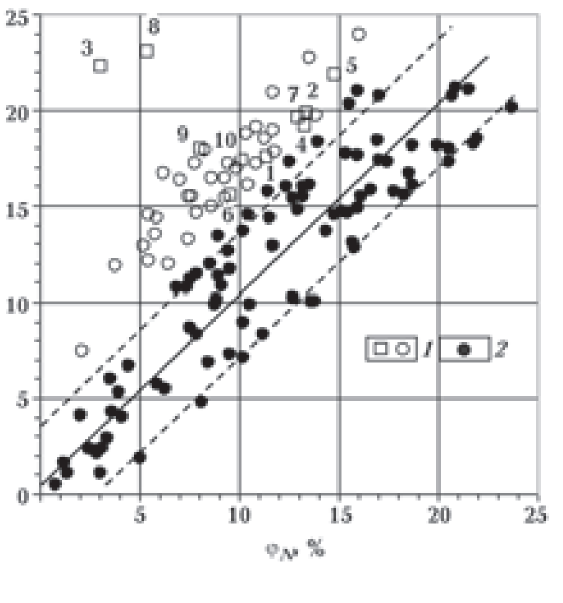

Fig. 5. Field example of neutron-density porosity crossplot: *1* — gas reservoir, *2* — water reservoir; 1—10 — number of gas reservoirs in Tab. 1.

and, to some extent, decrease of density, whereas the density porosity is higher than the true value through decrease in bulk density. Therefore in gas reservoirs the neutron porosity and the density porosity are apparent. Hence the determination of true porosity of gas reservoir using neutron logging or density logging separately is impossible. It is necessary to use the combination of these methods for determination of true porosity.

Historically true porosity in gas-bearing formations is estimated by applying the root-means-square equation [Gaymard, Poupon, 1968]:

$$\varphi = \sqrt{\frac{\varphi_D^2 + \varphi_N^2}{2}} \, . \qquad (14)$$

There are other approaches to determining the true porosity of gas reservoirs with the help of density-neutron loggings, namely as the following approaches:

$$\varphi = \left(\varphi_D + \varphi_N\right)/2 \, , \qquad (15)$$

$$\varphi = 0.55\varphi_D + 0.45\varphi_N \, , \qquad (16)$$

$$\varphi = (0.70 \pm 0.02)\varphi_D + (0.30 \pm 0.02)\varphi_N \, . \qquad (17)$$

$$\varphi = 0.63\varphi_D + 0.37\varphi_N \, . \qquad (18)$$

The arithmetic mean of values φ_D and φ_N (see Eq. (15)) is used, predominantly, for oil reservoirs, but it can be applied in estimating the true porosity as well as gas reservoirs [Hunt, Pursell, 1997]. The averaging equation (16) obtained according to the experimental data of measurements [Alger, Dewal, 1969]. The numerical factors on φ_D and φ_N in Eq. (17) were obtained when estimating the true porosity of the gas reservoirs (with mud-filtrate-invaded zone) by a procedure of fitting using least-squares method [DasGupta, 1997]. Equation (18) was obtained by empirical way by the example of near-surface aeration zone [Kulyk, Bondarenko, 2014]. We used Eq. (18) for determination of the true porosity of gas reservoirs occurring at shallow depths (up to about 1.0 km).

Thus the Eq. (14) and the Eq. (15)—(18) differ in the structure. As well numerical factors on φ_D and φ_N in Eqs. (15)—(18) substantially differ from each other in all variants.

The use of weighted arithmetic mean of the neutron apparent-porosity and density apparent-porosity with corresponding weight factors is a generalization of Eq. (15)—(18) [Kulyk et al., 2014]:

$$\varphi = \alpha_1\varphi_D + \alpha_2\varphi_N \, . \qquad (19)$$

Weight factors α_i (i=1, 2) are, by definition, the real non-negative numbers which are less than 1.

Weight factors α_i are normalized such that their sum is equal to 1:

$$\alpha_1 + \alpha_2 = 1\,. \qquad (20)$$

7.2. Weight factors of weighted arithmetic mean of φ_D and φ_N. In the context of accepted approximations it is possible to obtain the following values of the weight factors α_i:

$$\alpha_1 = (1-\omega_g)/(\Delta_\delta - \omega_g)\,,$$
$$\alpha_2 = (\Delta_\delta - 1)/(\Delta_\delta - \omega_g)\,. \qquad (21)$$

Hence, weight factors (20)—(21) used for obtaining the true porosity of gas reservoirs by Eq. (19) depend on the following factors: the matrix density, which is due to reservoir lithology; densities and hydrogen indices of pore water and pore gas; as well as *PT*-conditions of occurrence, which are the governing factors for gas density and hydrogen index of gas.

In Fig. 6 the depth dependences of weight factors α_i for main reservoir lithologies with conditional hydrostatic pressure are shown. Lithology distinctions bound up with various matrix density. As may be seen from Fig. 6, parameters α_i are substantially varying to a depth of about 4 km, while deeper the *PT*-conditions dependence is essentially weaker. In addition, the value of α_1 is greater than α_2 ($\alpha_1 > \alpha_2$) for depths under consideration with conditional hydrostatic pressure (CHP). Under CHP the weight factors α_i are approaching to 0.5 with increasing of depth (see Fig. 6).

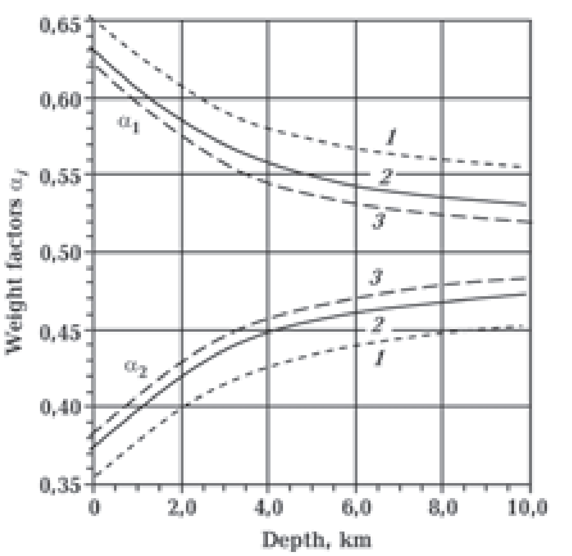

Fig. 6. Weight factors α_i vs depth occurrence of reservoir: *1* — dolomite, *2* — limestone, *3* — sandstone.

Fig. 7 compares the influence of CHP with the influence of AHFP on the weight factor α_1 for sandstone (dashed curves correspond to lower and upper limit of pressure gradient for AHFP). Calculation of parameter α_1 for examples of AHFP in gas fields of both Dnieper-Donets Depression (DDD) and other regions of the world (points) is also presented. As evident from the Fig. 7, the increase of pressure gradient causes the range extension of weight factors α_i. In so doing, both case of $\alpha_1 \geq \alpha_2$ and case of $\alpha_1 \leq \alpha_2$ are possible.

Thus as follow from Eq. (21) and Figs. 6, 7, weight factors α_i in the considered approximation possess the following properties:

– α_i substantially depends on *PT*-conditions (in so doing they depend primarily on reservoir pressure) through changes of both gas density ρ_g and hydrogen index of the gas ω_g;

– abnormally high *PT*-conditions strongly effect on the values of α_i;

– α_i depends on lithology (through density of solid constituent ρ_s);

– α_i is independent of both porosity and gas saturation;

– α_i is independent of both specification and metrological characteristics of particular neutron tools and density tools, as well as it is independent of borehole effects (hole diameter, casing etc.).

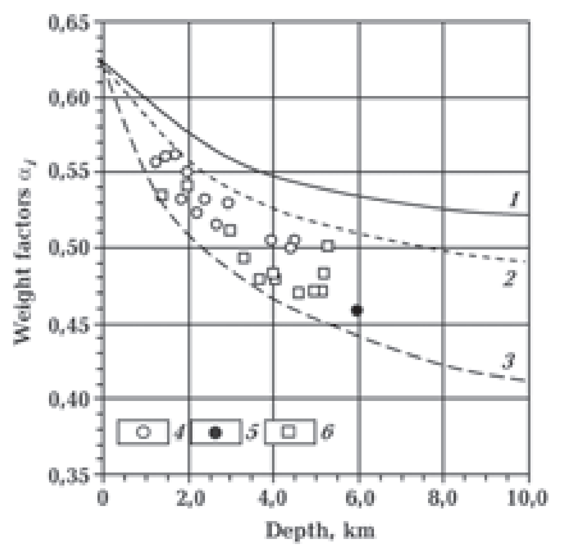

Fig. 7. Weight factor α_1 for sandstone. Pressure gradient: *1* — 10 MPa/km (CHP), *2* — 13 MPa/km (lower limit of AHFP), *3* — 23 MPa/km (upper limit of AHFP). Examples of AHFP: *4* — DDD [Melik-Pashaev et al., 1983], *5* — DDD [Lukin, 2014b]; *6* — other regions of the world [Petrenko et al., 2004].

7.3. True porosity and variants of averaging. In determining the true porosity of gas reservoirs using the different variants of averaging of apparent porosities φ_D and φ_N the problem of analysis of both accuracy and the area of application of each Eq. (14)—(19) depending on the *PT*-conditions, as well as lithology and other characteristics of formations arises.

Analytical expressions (21) for the weight factors α_i make it possible to calculate their values depending on both gas reservoir depth and lithology as well as to compare the calculated weight factors with numerical factors on φ_D and φ_N in Eq. (15)—(18). The results of calculations are presented in Tab. 2.

From Tab. 2 it follows that variants of averaging (15)—(18) do not fully agree with the theoretically substantiated variant (19)—(21).

This is more visually illustrated by Fig. 8. In Fig. 8 the results of calculation of true porosity for gas-bearing sandstone with porosity 20 and 10 % on a basis of methods (14)—(21) depending on occurrence depth are shown. Thickened line indicates the true porosity, calculated according to Eq. (19)—(21).

Comparison of the results of porosity determination of gas reservoirs using the above-described variants of averaging shows the following.

- The porosity obtained by using root-mean-square equation (14) is overstated over the whole depth interval and is weakly dependent on the depth; systematic relative error of this averaging variant is equal to about +10 % for any porosities.
- The porosity resulting from simple averaging of neutron and density porosity (see Eq. (15)) is understated over the whole depth interval; this porosity highly depends on the depth to a depth of 4 km and in this interval is actually unusable; deeper then 4 km systematic relative error is equal to about — 5 % for any porosities.
- Averaging (16) gives porosity, which is nearest to true porosity for actual depth; deeper then 1.5 km relative error is about ±3 %.
- Averaging (17) gives overstated porosity for any depth with systematic relative error of about +15 %.
- Averaging (18) is effective for shallow depth (less than about 1 km); at these depths error is less than about +5 %.
- Weighted arithmetic mean of porosity (19)—(21) within the accepted approach allows obtaining exact value of true porosity of gas reservoirs.

The field example of determining the true porosity of gas-saturated reservoir with the help of radioaktive logging by Eq. (19)—(21) is shown in Fig. 4 and Tab. 1.

8. Gas saturation from density-neutron loggings. Gas saturation, S_g, is determined as a ratio of volume of gas-filled pores to total volume of pores. For two-phase (gas—water) reservoirs the relation between gas saturation and water saturation is given by: $S_g+S_w=1$.

In an open borehole the water saturation S_w of conventional reservoirs is determined by electric logging, using the Archie's equation [Serra, 1984; Interpretation…, 1988; Ellis, Singer, 2008; Alimoradi et al., 2011]. However, in high-resistivity reservoirs, in unconventional low-permeability reservoirs, as well as in cased wells, this approach to determining the gas saturation ($S_g=1–S_w$) is non-working.

We have proposed a method for determining S_g [Kulyk et al., 2014], which allows determining gas saturation from the combination of radioac-

Table 2. Weight factors for true porosity determination of gas reservoirs by means of averaging the apparent neutron and density porosities

Depth, km	Eq. (15)		Eq. (16)		Eq. (17)		Eq. (18)		Eq. (19)—(21)					
	Limestone, sandstone, dolomite		Limestone		Limestone, sandstone, dolomite		Sandstone		Limestone		Sandstone		Dolomite	
	α_1	α_1	α_1	α_2	α_1	α_2	α_1	α_2	α_1	α_2	α_1	α_2	α_1	α_2
0.0	0.50	0.50	0.55	0.45	0.70±0.02	0.30±0.02	0.63	0.37	0.63	0.37	0.62	0.38	0.65	0.35
1.0							0.63	0.37	0.61	0.39	0.60	0.40	0.63	0.37
2.0							—	—	0.58	0.42	0.57	0.43	0.61	0.39
4.0							—	—	0.56	0.44	0.55	0.45	0.58	0.42
6.0							—	—	0.54	0.46	0.53	0.47	0.56	0.44
8.0							—	—	0.53	0.47	0.52	0.48	0.56	0.44

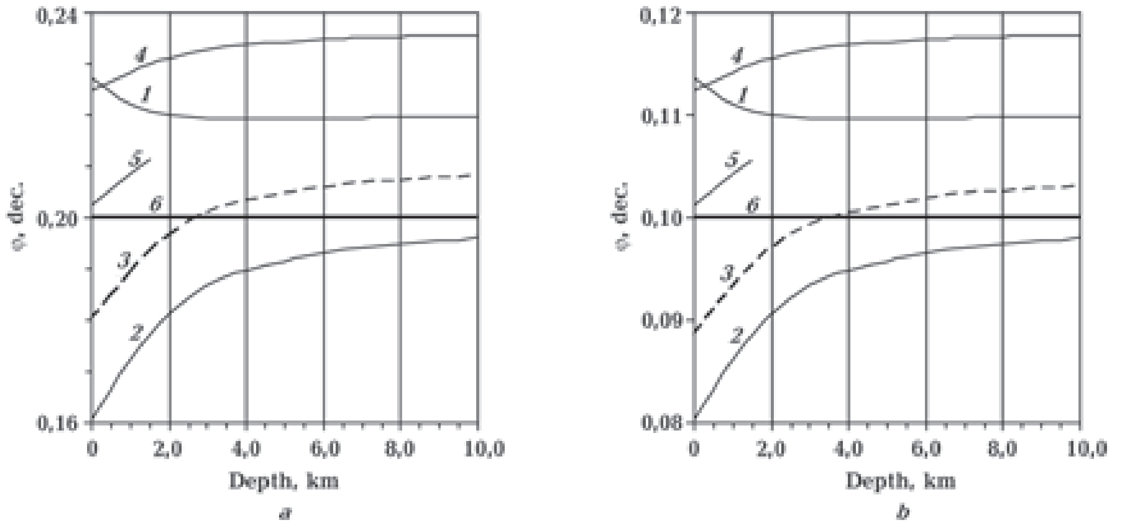

Fig. 8. Porosity of gas reservoir from density-neutron log porosity vs depth by: *1* — root-means-square equation (14); *2* — α_1=0.50, α_2=0.50 (Eq. (15)); *3* — α_1=0.55, α_2=0.45 (Eq. (16)); *4* — α_1=0.70, α_2=0.30 (Eq. (17)); *5* — α_1=0.63, α_2=0.37 (Eq. (18)); *6* — α_i from Eqs. (19)—(21). True porosity: *a* — φ=0.20, *b* — φ=0.10.

tive loggings practically in all cases of the absence of mud-filtrate invasion into reservoir. In case of presence of mud-filtrate invasion in open boreholes, proposed method allows determining residual gas saturation.

According to this method, the parameter S_g can be obtained as a value, which is proportional to the ratio of difference between density-apparent porosity and neutron-apparent porosity to true porosity:

$$S_g = \beta \, \frac{\Delta\varphi}{\varphi}, \tag{22}$$

where β is the proportionality factor, whereas Δφ and φ are determined by Eq. (13) and (19), respectively.

Within the approach, which is adopted in this paper, the proportionality factor β takes the form:

$$\beta = \frac{1}{\Delta_g - \omega_g}, \tag{23}$$

where Δ_g is determined by Eq. (9).

Thus, dimensionless proportionality factor β depends on matrix density, water density and gas density as well depend on hydrogen index of a gas.

Since the parameters of the gas (density and hydrogen index) depend on *PT*-conditions, the factor β varies with the depth. Depth dependence of the factor β at pressure gradient, which corresponds to conditional hydrostatic pressure, and at an average geothermal gradient is shown

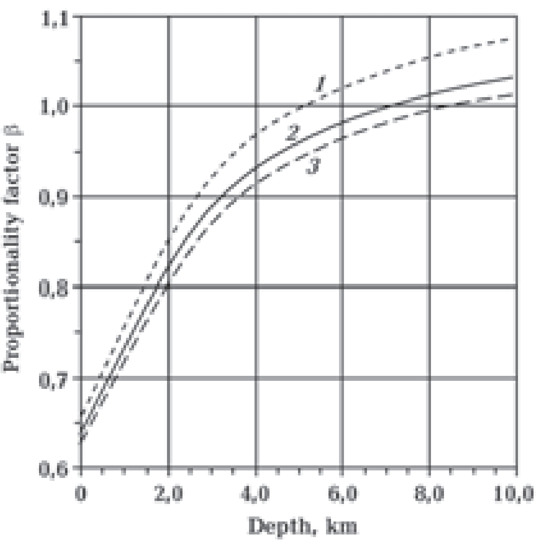

Fig. 9. Proportionality factor β vs depth occurrence of reservoir: *1* — dolomite, *2* — limestone, *3* — sandstone.

in Fig. 9 for sandstone, limestone and dolomite. There are sufficiently strong depth dependence and the relatively weak lithology dependence of the factor β, as indicated in Fig. 9.

Fig. 10 gives calculation data of the factor β (points) for sandstone with abnormally high formation pressure (by the example of gas fields of both Dnieper-Donets Depression and other regions of the world, occurring at the various depths). Dashed curves correspond to the lower and to the upper limits of pressure gradient for

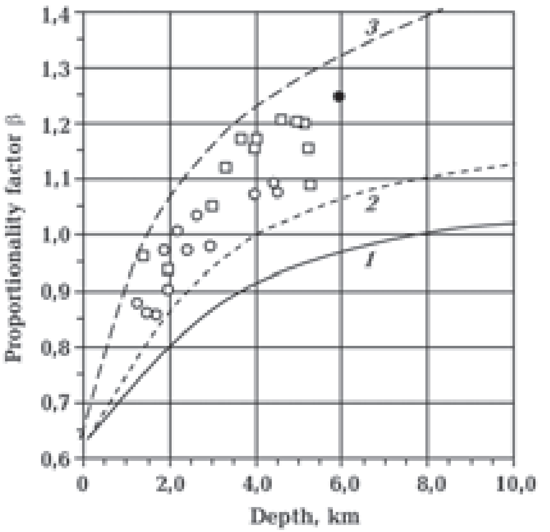

Fig. 10. Proportionality factor β for sandstone. Legend see in Fig. 7.

abnormally high formation pressure (AHFP). For comparison the depth dependence of factor β for typical *PT*-conditions is also given (curve *1*). It is seen that the dependence of factor β on *PT*-conditions increases sharply for the AHFP.

The example of determination of gas saturation on the basis of combination of radioactive loggings in cased well according to Eq. (22)—(23) is presented in Fig. 4 and Tab. 1.

9. Conclusions. The problem of identification of gas reservoirs and determination of their petrophysical parameters in principle can not be solved by separate (individual) logging methods and requires a combined approach. One such approach is the use of combination of radioactive logging methods (density logging, neutron logging and gamma ray logging), which works in both open and cased wells.

The paper is focused on the development of theoretical and applied aspects of the gas reservoirs investigation with the help of combination of radioactive loggings on the basis of simple models. However, these simple models take into account the basic properties of the subject under investigation and conditions of logging, as well as allow obtaining results in an explicit form. We used the simplest petrophysical model of reservoir and simplified relation between measured and petrophysical parameters. Identification of gas reservoirs, choice of optimal methods of obtaining their true porosity, quantitative estimation of porosity and gas saturation taking into account *PT*-conditions of reservoir occurrence are consecutively considered.

Combination of radioactive loggings allows identifying gas reservoirs by the parameter of disagreement between the density and the neutron porosity, which are presented in the form of logs along the investigated borehole section or a part thereof. In gas reservoirs a parameter of disagreement is positive and increases with increasing volume of gas in the rock. Together with this approach, it is advantageous to use the method of density-neutron porosity crossplot for identification of gas reservoirs.

It has been proposed that in general case, the true porosity of gas reservoirs is determined by the combination of radioactive loggings as a weighted arithmetic mean value of the measured both density-apparent porosity and the neutron-apparent porosity with weight factors, which are derived theoretically. The weight factors depend on *PT*-conditions (primarily they depend on the reservoir pressure) due to variation in both gas density and hydrogen index of gas, as well as depend on reservoir lithology. The estimation of values of weight factors for hydrostatic pressure and for abnormally high formation pressure has been carried out.

Another important parameter is the gas saturation, which can be obtained on data of radioactive logging as quantity, which is proportional to the ratio of difference between measured density-apparent porosity and neutron-apparent porosity to the determined true porosity. Proportionality factor is estimated by calculated way taking into account *PT*-conditions similarly to the weight factors.

The proposed method allows determining the gas saturation practically in all the cases of absence of mud-filtrate invasion into reservoir (cased wells with dissipated or unformed invaded zone, open wells when drilling on oil-based mud, unconventional reservoirs with low permeability). In case of presence of mud-filtrate invasion in open boreholes, proposed method allows determining residual gas saturation.

In the considered approach, the cited both the weight factors and the proportionality factor are independent of the following: particular values of both porosity and gas saturation; both specification and metrological characteristics of neutron tools and density tools; borehole effects.

It is shown, that the investigated parameters are substantially dependent on the hydrostatic pressure and the overburden pressure; estimation of affecting of abnormally high formation pressures for gas fields of the Dnieper-Donets Depression and other regions of the world is presented.

Efficiency of the developed approaches is demonstrated for the cased coal-bed methane well (without mud filtrate invasion zone).

In general, the investigation of conventional and unconventional gas reservoirs with the help of radioactive logging shows practical universality and high informativity of combination approach for determination of set of petrophysical parameters. Developed approaches allow the generalization towards account of more realistic petrophysical and calculated models. Combination of radioactive loggings and other logging methods (electric logging, acoustic logging) allows extending both capabilities of logging and a set of determined parameters.

Identification of gas reservoirs and determination of their parameters by combination of radioactive logging methods

The paper proposes a new approach for using a combination of radioactivity logging (neutron and density logging), which allows determining a set of gas reservoir parameters (nature of saturation, true porosity, gas saturation) taking into account influence of the pressure and temperature conditions of occurrence. Analysis of the ways of averaging the neutron-apparent porosity and the density-apparent porosity for obtaining the true porosity was made. Method of determination of gas saturation, which uses the same combination of radioactivity logging as in determining the true porosity of gas reservoirs, was developed. The results presented in the paper, were obtained over a wide interval of depth (up to 10 km). Application of developed approaches for determination of petrophysical parameters of gas reservoirs is demonstrated by the example of cased coalbed methane well.

Key words: gas reservoirs, pressure-temperature conditions of occurrence, combination of neutron logging and density logging, identification of gas reservoirs, apparent porosities, true porosity, gas saturation.

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