Parameterization permeability curves for the simulation of oil displacement with gas and water at pressures below the saturation pressure

Yu.A. Zarubin[1*], M.V. Gunda[2], M.I. Yurova[2], O.M. Zazulyak[3]

[1] *LLC «Research and production company «Centre of Oil and Gas Resources»; 12, Viacheslava Chornovola Str., Kyiv, 01135, Ukraine*

[2] *Subsidiary enterprise «Scientific-research institute of oil and gas industry» («Naukanaftogaz») of National Joint Stock Company (NJSC) «Naftogaz of Ukraine»; 8, Kyivska Str., Vyshneve, Kyiv region, 08132, Ukraine*

[3] *Research and Project Institute PJSC «Ukrnafta»; 2, Pivnichny Boulevard named after Pushkin, Ivano-Frankivsk, 76019, Ukraine*

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Abstract

Numerical modeling of water alternating-gas processes requires adequate representation of dependencies of relative phase permeability for oil, gas and water upon saturation of the reservoir. On the basis of the agreement of the results of numerical modeling with laboratory experiments parameterization of Korea functions for phase permeability of Eocene sandstone for oil, gas and water at pressure below the saturation pressure has been carried out. Correlation between meters of membership functions with initial gas saturation, formed as a result of the allocation of oil dissolved gas, has been established.

Key words: *Eocene sandstone, numerical modeling, phase permeability, saturation pressure, water alternating-gas processes.*

Introduction

Modern tendencies in application of oil recovery enhancement methods define significant interest towards water-alternating-gas methods which are done to be classified as water-alternating-gas processes. Such methods are considered to be able to raise final oil recovery up to 5–10 % [1]. In domestic literature such processes are usually called gas-water or water-gas repression.

Due to broad range of conditions and diversity of technologies, WAG methods depending on the phase state of hydrocarbons after mixing of injected gas with formation oil are divided into miscible and immiscible displacement (correspondingly MWAG, IWAG). Depending on gas injection sequence, simultaneous injection, simultaneous WAG injection and hybrid WAG injection [1, 2] are defined. The latter presumes consequent injection of large portions of gas with subsequent insignificant amount of water and gas portions. (Jackson et al., 1985; Magruder et al., 1990; Hustad et al., 2002).

Natural gas injection for oil recovery enhancement has been applied on oil fields of oligocene deposits (menilite suite) of deep-seated fold of Bytkov–Babchensk oil and gas condensate field which is one of the largest in Ukraine. Development of oil deposits of deep-seated oil deposits was started in 1951 on dissolved gas regime. To maintain formation pressure with the help of waterflooding, in 1958–61 water injection into formation was researched but due to low water intake rate and high pressures these operations were terminated.

Thanks to discovery of significant gas condensate deposits with high formation pressure in deep-buried Eocene sediments, gas injection technology aimed at oil recovery enhancement in menilite oil deposits (Bytkovskyy, Pasichnyanskyy and Lyubizhnyanskyy blocks) has been implemented. On the first stage (1963–1969) the development was accomplished by downhole overflow of high-pressure gas into oil deposits without its preliminary treatment at condensate factor of 60 g/m^3.

On the second stage (1971–1985) 169–301 mln m^3/year of gas was injected with the help of high-pressure compressors. Besides, almost simultaneously (1971–1988) water was injected with gradual building-up from 10 thousand m^3 up to 912 thousand m^3. Gas injection was terminated in 1995. Later on since 1986 it has been developed with formation pressure maintaining and water injection (200 thousand m^3/year) in a combined mode under the conditions of slow formation pressure reduction [4].

Altogether during development of deep-seated fold oil deposits more than 8.2 mln of tonnes of oil and 10.65 billion m^3 of gas have been produced. Oil

* Corresponding author: info@cogr.com.ua

recovery coefficient being attained with the help of WAG injection at the beginning of 2015 is evaluated at 11.6%.

Positive experience, obtained in complex geological and hydrodynamic conditions of oil deposits of deep-seated fold, let us consider the perspective of WAG application on the other deposits of oligocene (menilite) oil and gas bearing complex, within the limits of which approximately 80% of geological oil deposits of Karpaty region have been found.

The validity of technological decisions made in the course of planning of water and gas methods of influence upon the deposit is in many ways stipulated by the quality of numerical simulation of technological processes. Difficulty and complexity of physical, chemical and hydrodynamic phenomena, accompanying joint filtration of oil and gas, make high demands of numerical model parameterization quality.

In most programs for numerical hydrodynamic simulation of formation systems to close system of filtration equations, integrated Darcy's law is used as an equation of motion:

$$\boldsymbol{w}_i = -\frac{k_i(s_i)}{\mu_i}\,\boldsymbol{grad}\ p_i\,, \tag{1}$$

where $\boldsymbol{w}_i$ is the *i*-phase filtration velocity; $k_i(s_i)$ is the relative porous medium permeability coefficient for *i*-phase; μ_i is the dynamic viscosity of *i*-phase; $\boldsymbol{grad}\ p_i$ is the pressure gradient for i-phase.

Dependencies of phase permeability coefficients for phases, participating in motion, upon saturation of porous medium of one of the phases are usually called phase permeability curves. In hydrodynamic simulators these curves must be preset as input data in the form of tables or analytic dependencies. It is common knowledge that phase permeability curves significantly determine simulation results and their updating is used to match the model with the field development history.

For macro-homogenous model of porous medium phase permeability curves are the only instrument that let us match the results of numerical and full-scale simulation. In other words phase permeability curves must be specified in such a way that numerical simulation is adequate besides in the widest possible range of boundary and initial conditions.

Dependencies of phase permeability upon saturation are often obtained using the results of laboratory tests in displacement of one fluid with the other one in core samples, so-called nonsteady state method. Identification task adds up to matching of mathematical model with test results. If only certain type of function is used, approximating phase permeability curves, then coefficients of these functions are to be identified. A large number of correlations and approximating functions for phase permeability dependencies upon saturation, used for instance in [2, 5] has been suggested. Power function, introduced by A. Corey (Corey, 1954 [3]) is best suited for numerical simulation and doesn't impose additional restrains, especially on definition field. This function can be written down as:

$$k_{rog}\left(s_g\right) = k_{rogcg}\left[\frac{1-s_g-S_{org}-S_{wcon}}{1-S_{gcon}-S_{org}-S_{wcon}}\right]^{Nog},$$
$$k_{rg}\left(s_g\right) = k_{rgcl}\left[\frac{s_g-S_{gcrit}}{1-S_{gcrit}-S_{org}-S_{wcon}}\right]^{Ng}; \tag{2}$$

$$k_{rw}\left(s_w\right) = k_{rwiro}\left[\frac{s_w-S_{wcrit}}{1-S_{wcrit}-S_{oriw}-S_{gcon}}\right]^{Nw},$$
$$k_{row}\left(s_o\right) = k_{rocw}\left[\frac{s_o-S_{orw}}{1-S_{wcon}-S_{orw}-S_{gcon}}\right]^{Now}, \tag{3}$$

where k_{rw} is the relative water permeability; k_{row} is the relative oil permeability in case of collaborative filtering with water; k_{rog} is the relative oil permeability in case of collaborative filtering with gas; k_{rg} is the relative gas permeability; k_{rwiro} is the relative water permeability at residual oil saturation; k_{rocw} is the relative oil permeability at connate water saturation; k_{rogcg} is the relative oil permeability at critical gas saturation value; k_{rgcl} is the relative gas permeability at critical value of liquid saturation ($S_{org}+S_{wc}$); s_w, s_o, s_g are the water saturation, oil saturation and gas saturation respectively; S_{orw}, S_{org} are the residual oil saturation in case of water and respectively gas displacement; S_{oriw} is the critical oil saturation in case of oil displacement with water; S_{wcrit} is the critical water saturation in case of oil displacement with water; S_{wcon} is the connate water saturation; S_{gcrit} isa the critical gas saturation; S_{gcon} is the residual gas saturation; N_w, N_{ow}, N_{og}, N_g are the power exponents.

Attention should be paid to the difference between connate fluid saturation and critical saturation values. By critical saturation value is meant saturation at which filtering of the given fluid is terminated if it functions as a displacement agent (the process is going on in the direction of rise of its saturation). Residual saturation is understood as saturation at which fluid displacement is terminated by its displacement by the other fluid (the process is going on in the direction of decrease of its saturation) (Tarek 2006 [3]).

Correctness of use of phase permeability values ideally obtained on the basis of tests results at steady filtration has been in doubt over and over again (e.g. refer to Konovalov 1988, Jones & Roszelle 1978 [4, 5]). Such critical attitude can be justified by unsatisfactory predictive possibilities of replacement theory, built on Buckley–Leverett assumptions, especially while determining leap of saturation leap at the displacement front (Konovalov, 1988 [4]), and divergence in relative permeability functions, defined under stable filtration conditions and calculated on the basis of displacement results (Efros 1956, [6]). Phase permeability curves and correspondent distribution function, identified on the basis of displacement characteristic, are quite descriptive, but they hold only for certain experiment conditions. The main reason is that multiphase flow forms different structures in stationary and non-stationary experiments. Such authors as Jones & Roszelle 1978 [5] define this thesis as the dependence of phase permeability curves upon saturation formation prehistory.

Thereby, for parameterization of functions (2) and (3), application of which will be adequate in the course of numerical simulation of gas-alternating-water injection, the results of two series of experiments are used. These experiments are dealing with gas-oil or water-oil displacement with the formation of initial saturation in approximate reservoir conditions. Samples of homogenous fine-grained Eocene sandstones, pulled out from the hole No. 116 of Dolynske Field were used as a porous medium. For residual water saturation, formation water with salinity of 200–220 g/l was used. Recombined oil samples from Bytkivske and Dolynske fields and gas from Eocene deposits of Bytkivske field with gas saturation pressure of 17.0–26.3 MPa and gas content of 110–157 m^3/m^3 were used for experiments.

Gas-oil displacement

Parameterization of oil-gas phase permeability curves (2) is based on the results of 13 gas-oil displacement experiments (oil is from Bytkivske field), conducted on three samples of porous medium with the diameter of 2.80–2.85 mm, length of 39.5–42.3 cm, porosity of 12.2–12.7%, absolute permeability of 9.1–14.7 mD and connate water saturation of 21.2–28.8 %.

Experiments were conducted at different initial pressure values in the range from pressure value of oil saturation with gas and up to half of its value, corresponding to initial gas saturation of 0–18.5%.

Numerical simulation of gas-oil displacement experiments was accomplished by compositional simulator GEM CMG. In compliance with formulas (2), accepted for phase permeability curves approximation, it was necessary to pick up such saturation pivotal values $(S_{org}, S_{gcrit}, S_{gcon})$, permeability boundary values (k_{rogcg}, k_{rgcl}) and power exponents (Nog, Ng), under which numerical simulation results would match with experimental data of oil displacement on reservoir samples. Relatively high pressure gradient (of about 4 MPa/m) in the course of experiments stipulated absence of capillary pressure impact upon simulation results.

The task of coefficients identification in equations (2) was being solved by alternating-variable descent method with manual control of direction and descent step to minimization of mean square divergence $\Delta\beta$ between experimental βex_i and design $\beta calc_i$ N points of displacement coefficient dependence upon flushing volume:

$$\Delta\beta^2 = \frac{1}{N}\sum_{i=1}^{N}(\beta ex_i - \beta calc_i)^2 . \qquad (4)$$

While selecting initial approximations of equations coefficients (2) their physical interpretation has been taken into consideration (Fig. 1). Maximum values of phase permeability in initial approximation were taken equal to 1 $(k_{rgol} = k_{rogcg} - 1)$. Connate water saturation was taken as constant and equal, formed in the course of filtration experiments preparation. Initial approximation to residual oil saturation was evaluated to the maximum of displacement coefficient, achieved during certain experiment $S_{org} = \beta_{\max}(1 - S_{wcon})$.

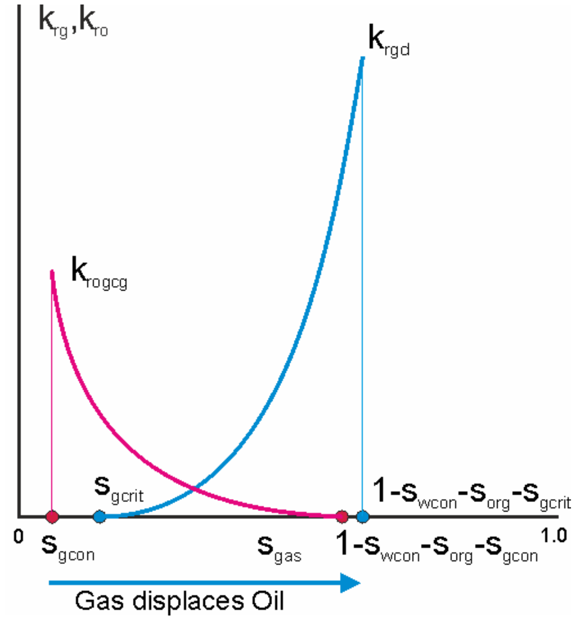

Figure 1 – Relative phase permeability curves

It is obvious that oil filtration must start as soon as gas saturation exceeds initial saturation, formed before the start of gas-oil displacement. That's why initial approximation for critical gas saturation was taken equal to the initial value:

$$S_{gcrit} = S_{ginitial} . \qquad (5)$$

Out of assumption that final gas saturation corresponds with pore space, occupied with gas, emitted from space, filled with residual oil after reduction of pressure below saturation pressure. Its initial approximation was evaluated in accordance with the formula:

$$S_{gcon} = S_{ginitial}\frac{S_{org}}{(1 - S_{wcon})} . \qquad (6)$$

Initial gas saturation of sample $S_{ginitial}$ after reduction of initial pressure p_{ini} to the value, lower than saturation pressure p_{bbp} can be evaluated according to the formula:

$$S_{ginitial} = \frac{(1 - S_{wcon})}{B_{oil}} G \frac{p_{bbp} - p_{ini}}{p_{bbp}} \frac{p_0}{p_{ini}},$$

where G, B_{oil} are the gas content and volume coefficient of formation oil under saturation pressure; p_0 is the standard pressure.

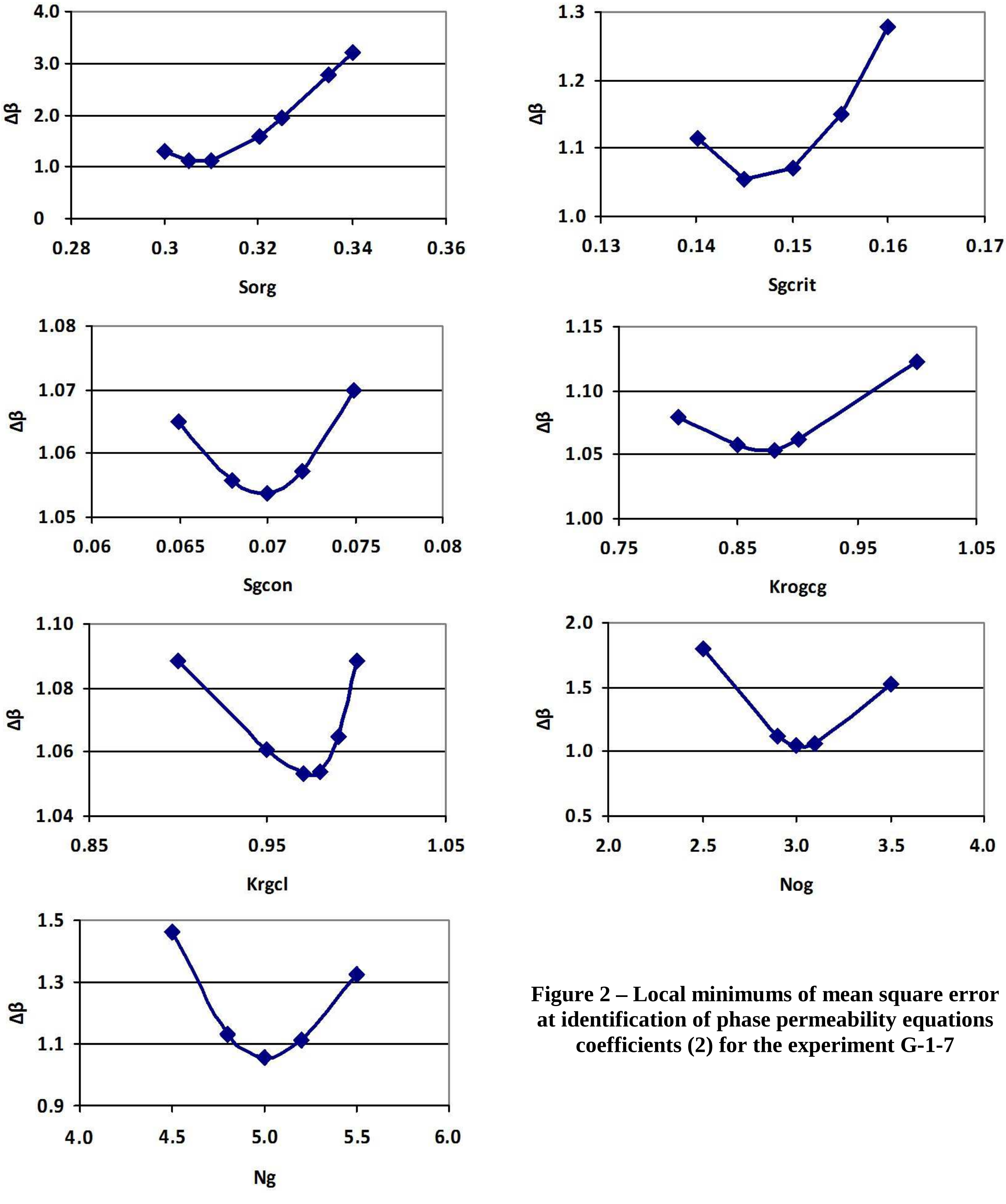

Figure 2 – Local minimums of mean square error at identification of phase permeability equations coefficients (2) for the experiment G-1-7

Initial approximations for power exponents in equations (2) on the basis of preliminary numeric experiments hereafter were taken equal to $Ng = 5$ and $Nog = 3$.

To illustrate the procedure of equations coefficients identification (2), Fig. 2 displays position of local coordinate-wise minimums of divergence between data of physical and numeric experiments, using the example of 1–7.

The results of matching of model and experimental data for 13 experiments on oil displacement from Eocene sandstones are displayed in Fig. 3 and Fig. 4.

Identified values of equations coefficients, obtained in the course of iteration procedures, are listed in Table 1.

On the basis of identification results, part of equations coefficients (2) irrespective of experimental conditions preserves value close to constant while the other part significantly correlates with the initial gas saturation of sample, formed before displacement of oil with gas.

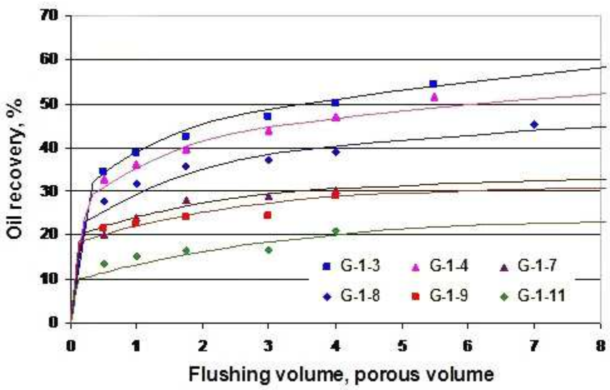

Figure 3 – The results of gas-oil displacement simulation for a series of experiments on the sample No. 1

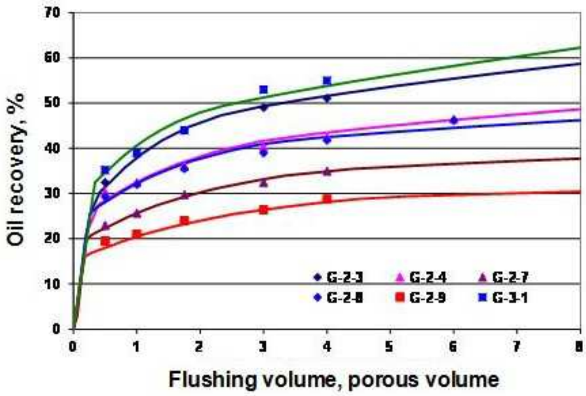

Figure 4 – The results of gas-oil displacement simulation for a series of experiments on the samples No. 2 and No. 3

Table 1 – Coefficients of equations of phase permeability curves at gas-oil displacement

Experiment	Connate water saturation	Initial gas saturation	S_{org}	S_{gcon}	S_{gcrit}	k_{rogcg}	k_{rgcl}	Nog	Ng	Mean square divergence, %
G-1-3	0.300	0	0.300	0	0	0.83	1.00	3.0	5.0	1.19
G-2-3	0.312	0	0.275	0	0	0.88	0.86	3.0	4.9	0.44
G-3-1	0.288	0	0.275	0	0	0.61	1.00	2.9	4.8	1.55
G-1-4	0.300	0.046	0.280	0.025	0.050	0.88	0.95	3.0	5.0	1.01
G-2-4	0.312	0.047	0.290	0.020	0.020	0.88	0.88	3.0	5.0	0.88
G-1-8	0.300	0.082	0.280	0.050	0.090	0.88	0.98	2.9	4.9	1.01
G-2-8	0.312	0.074	0.285	0.040	0.076	0.88	1.00	3.1	4.8	1.27
G-1-7	0.300	0.137	0.310	0.070	0.145	0.88	0.97	3.0	5.0	1.05
G-2-7	0.312	0.133	0.325	0.070	0.130	0.88	0.88	3.0	5.0	0.49
G-1-9	0.300	0.175	0.310	0.070	0.200	0.88	0.88	3.0	5.0	0.79
G-2-9	0.312	0.159	0.335	0.087	0.160	0.80	1.00	2.9	5.1	0.35
G-1-11	0.300	0.238	0.295	0.130	0.250	0.88	1.00	3.0	5.0	1.70
G-2-11	0.312	0.222	0.362	0.130	0.220	0.88	1.00	3.0	5.0	0.36

Maximum value of gas phase permeability (average value of $k_{rgcl} = 0.849 \pm 0.038$)[1], oil phase permeability (average value of $k_{rogcg} = 0.954 \pm 0.057$) and power exponents (average value of $Ng = 4.962 \pm 0.087$, $Nog = 2.985 \pm 0.055$) are considered to be close to constant.

Linear connection of values of residual S_{gcon} and critical gas saturation S_{gcrit} with initial gas saturation value $S_{ginitial}$ is clearly traced. Though, values of residual and critical gas saturation (Fig. 5) practically coincide with evaluations of their initial approximations by formulas (5) and (6), which proves interpretation of their physical meaning.

The influence of initially formed gas saturation upon residual oil saturation value S_{org} is ambiguous. Initial gas saturation of less than 8–10% doesn't influence residual oil saturation value noticeably. There is statistically improbable increase of residual oil saturation with the increase of initial gas saturation at larger values.

Thus, phase permeability dependencies are obtained as a result of experimental data treatment at collaborative filtering of oil and gas. They can be used in compositional simulators for validated simulation of gas-oil displacement processes from Eocene sandstones in a broad range of conditions. The main peculiarity of oil-gas phase permeability set (Fig. 6) is the necessity of their change and scaling in accordance with the initial gas saturation of porous medium.

Water-oil displacement

For parameterization of oil-water phase permeability curves (3) the results of 9 experiments on water-oil displacement are used. Oil is from Dolynske field. The experiments are conducted, using three

[1] Hereinafter 90% confidence level is accepted to determine the confidence interval and statistical estimates.

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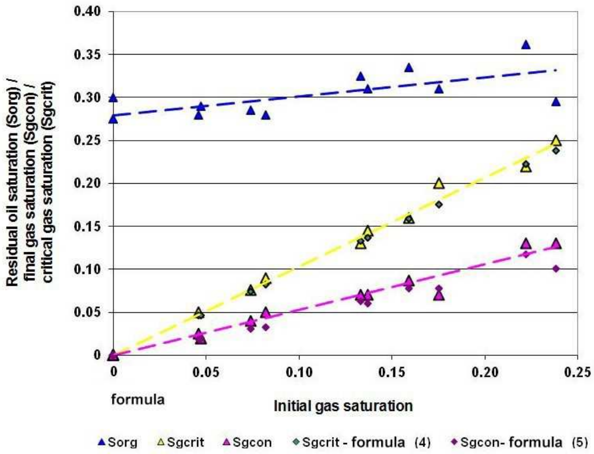
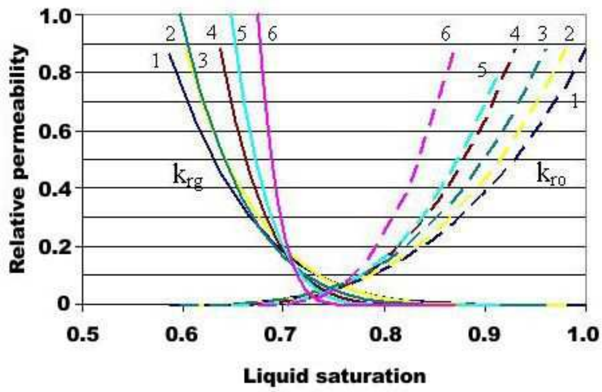


Figure 5 – Interconnection of identified coefficients S_{org}, S_{gcon} and S_{gcrit} with initial gas saturation



1 – 0, 2 – 0.047, 3 – 0.074, 4 – 0.133, 5 – 0.312, 6 – 0.222

Figure 6 – Identified relative permeability at gas-oil displacement from core sample No 2 at the initial gas saturation

samples of porous medium, prepared from Eocene sandstones with the diameter of 2.80–2.86 mm, length of 39.3–42.8 cm, porosity 12.2–12.5%, absolute permeability of 3.0–14.7 mD and connate water saturation of 27.3–33.2 %.

Like in the preceding series, part of experiments has been conducted at the pressure, exceeding the pressure of oil saturation with gas, correspondingly at free gas absence in porous space. The other part has been conducted after sample pressure reduction and formation of initial gas saturation of 5.6–25.5%.

Numerical simulation of gas-oil displacement experiments has been carried out at the compositional simulator GEM CMG. In compliance with formulas (3), accepted for phase permeability curves approximation (3), the identification task was solved with the help of alternating-variable descent method with the definition of saturation pivotal values (S_{orw}, S_{gcon}), permeability boundary values (k_{rocw}, k_{rwiro}) and power exponents (Now, Nw), minimizing mean square divergence (4) between experimental and design displacement coefficients.

Initial approximation for residual oil saturation has been estimated by maximum displacement coefficient, achieved in the course of certain experiment $S_{org} = \beta_{\max}(1 - S_{wcon})$.

Due to the fact that the procedure of samples preparation for water-oil displacement simulation implied that a sample contained only connate water, it was assumed that:

$$S_{wcon} = S_{wcrit}.$$

Similarly oil displacement couldn't be finished before residual oil saturation, so

$$S_{oirw} = S_{orw}.$$

Initial approximation for final gas saturation like in gas-oil displacement experiments, has been evaluated according to the formula (6).

Preliminary numerical experiments showed that phase permeability maximum values could be gone through as constant $k_{rocw} = 0.88$, $k_{rocw} = 0.41$ and deleted from identification procedure.

Initial approximations for power exponents in equations (3), being based on preliminary numerical experiments, hereafter were taken to be equal to $Ng = 3$ and $Now = 1.5$.

To illustrate the equations coefficients identification procedure (3) in the course of water-oil displacement, Fig. 7 displays position of local coordinate-wise minimums of divergence between physical and numerical experiments data, using the example of W-3-4 experiment.

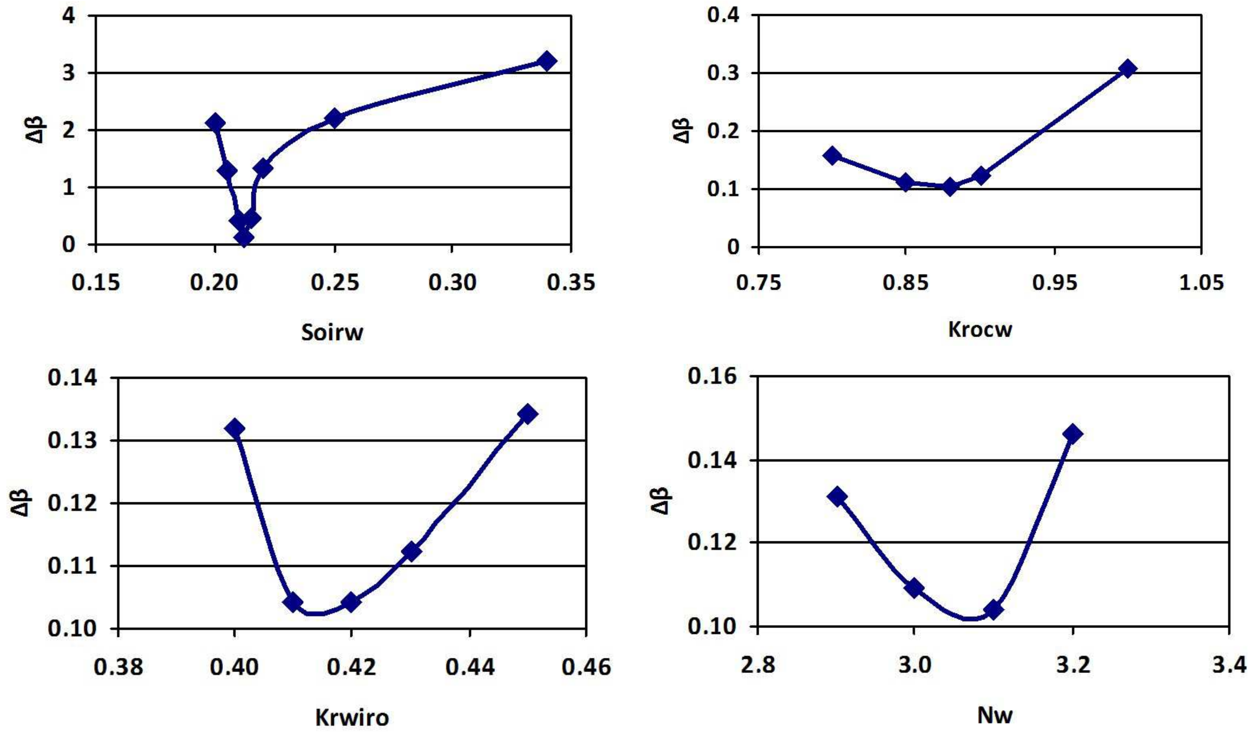
Obtained dependencies of phase permeabilities at collaborative filtering of oil and water coordinate full-scale and numerical simulation data fairly good (Fig. 8 and Fig. 9). Mean square error inaccuracy of divergence between experimental and design displacement coefficients doesn't exceed 0.7 %.

Identified values of equations coefficients, obtained in iteration procedures, are listed in Table 2. All coefficients are taken to be equal to constant, including power exponents at mean value of $Nw = 3.044 \pm 0.045$ and $Now = 1.544 \pm 0.088$.

For experiments, conducted at the pressure, lower than the pressure of oil saturation with gas, residual gas saturation was being well predicted on the basis of correlation (5) and didn't have to be specified in the iteration process.

An exception is the value of the residual oil saturation, which happened to be closely correlated with the initial gas saturation of the sample, formed before displacement (Fig. 10). In contrast to the results of experiments on gas-oil displacement, pressure drop below the saturation pressure of the sample prior to the water-oil displacement, leads to a decrease in residual oil saturation and hence to increase of displacement completeness. For the experimental conditions this decrease is nonmonotonic. Residual oil saturation coefficient is minimal at the initial gas saturation of about 20%. For oil from Dolynske field that was used during the experiments, such gas saturation was formed approximately when the pressure was decreased to 40% of the saturation pressure.

Dependencies of relative phase permeability of Eocene sandstones for oil and water, obtained by parameterization of Korea features on the results of water-oil displacement at different initial gas saturation values, are shown in Fig. 11. Following the classification by Creig (Creig 1971) [7] the form of the obtained phase permeability curves is for sandstones with intermediate wettability.



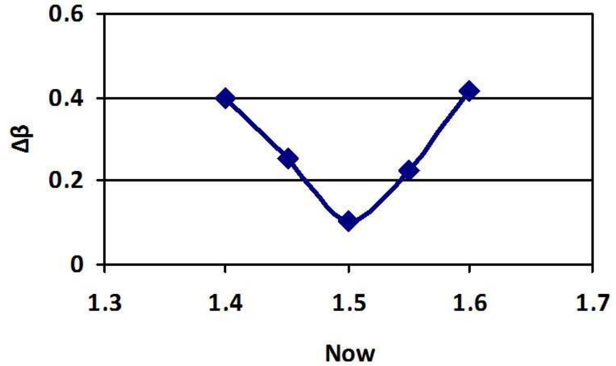


Figure 7 – Local minimums of mean square error at identification of phase permeability equations coefficients (3) for the experiment W-3-4

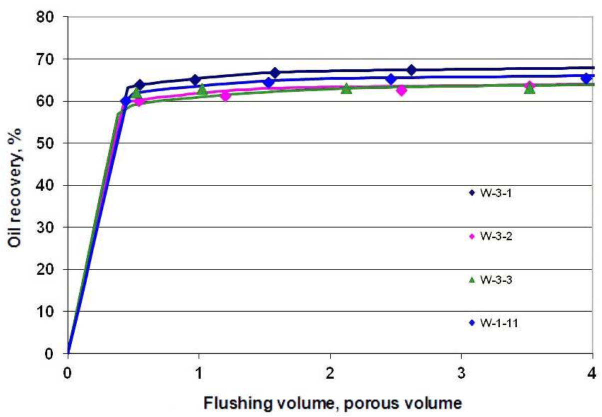


Figure 8 – The results of water-oil displacement simulation for a series of experiments at a sample pressure higher than saturation pressure

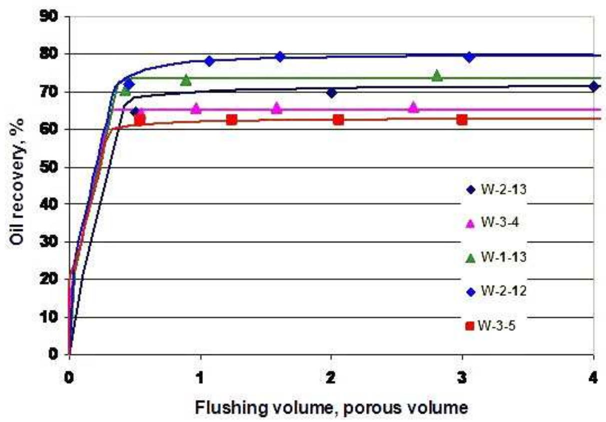


Figure 9 – The results of water-oil displacement simulation for a series of experiments at a sample pressure lower than saturation pressure

Table 2 – Equations coefficients for phase permeability curves in the course of water-oil displacement, coordinating experimental and model data

Experiment	Connate water saturation	Initial gas saturation	S_{orw}	S_{gcon}	k_{rocw}	k_{rwiro}	Nw	Now	Mean square deviation, %
W-3-1	0.287	0	0.230	0	0.88	0.41	3.0	1.6	0.515
W-3-2	0.306	0	0.270	0	0.88	0.41	3.0	1.6	0.688
W-3-3	0.332	0	0.255	0	0.88	0.41	3.0	1.2	0.268
W-1-11	0.250	0	0.265	0	0.88	0.41	3.0	1.6	0.119
W-2-13	0.254	0.056	0.205	0	0.88	0.41	3.0	1.6	0.671
W-3-4	0.323	0.118	0.212	0.048	0.88	0.41	3.1	1.5	0.104
W-1-13	0.274	0.195	0.167	0.060	0.88	0.41	3.2	1.5	0.124
W-2-12	0.273	0.196	0.148	0.095	0.88	0.41	3.0	1.6	0.582
W-3-5	0.329	0.255	0.220	0.095	0.88	0.41	3.1	1.7	0.259

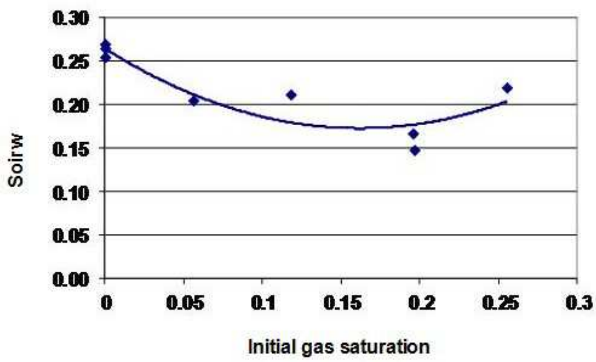
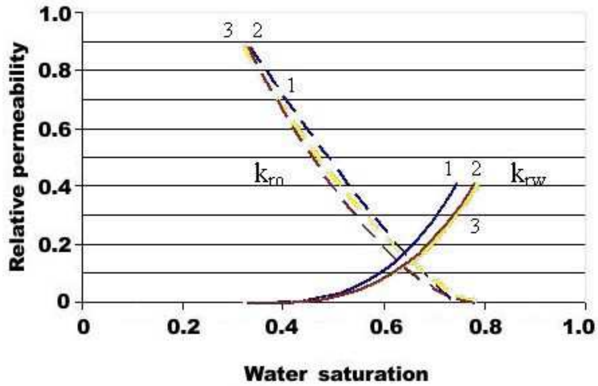


Figure 10 – Interconnection of the residual oil saturation in the course of water-oil displacement with the initial sample gas saturation



1 – 0, 2 – 0.118, 3 – 0.255

Figure 11 – Identified relative phase permeability values at water-oil displacement from core sample №3 at the initial gas saturation

Conclusions

On the basis of laboratory investigations of displacement of oil with water and gas and their matching with the hydrodynamic simulation results, phase permeability functions of Eocene sandstones of the Prycarpathian Region have been parameterized. For approximation of dependencies of phase permeabilities upon saturation Corey power functions have been used (Corey 1954). Features of phase permeabilities behavior when oil is displaced after a pressure drop below the saturation pressure become apparent in the significant interconnection of some parameters with the initial gas saturation, emerging as a result of dissolved gas discharge from oil.

With the subsequent gas-oil displacement, a part of parameters in phase permeability functions (2) significantly correlates with the initial gas saturation of a sample, formed before gas-oil displacement. Linear connection of values of residual S_{gcon} and critical gas saturation S_{gcrit} with the value of formed initial gas saturation $S_{ginitial}$ can be easily traced. Power exponents Ng and Nog are considered to be proximal to constant, as well as maximum phase permeability values of gas k_{rgcl} and oil k_{rgocg}.

Residual oil saturation S_{orw} is closely linked with initial gas saturation $S_{ginitial}$ of a sample in the course of water-oil displacement. Reduction of pressure below the saturation pressure of the sample prior to the displacement of oil with water leads to a decrease in residual oil saturation, and hence to increase of the displacement completeness. For the experimental conditions this decrease is nonmonotonic. Coefficient of residual oil saturation is minimal at the initial gas saturation of about 20%.

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Параметризація кривих фазових проникностей для моделювання витіснення нафти водою і газом при тисках нижче тиску насичення

Ю.О. Зарубін[1], М.В. Гунда[2], М.І. Юрова[2], О.М. Зазуляк[3]

[1] *ТОВ «НВП «Центр нафтогазових ресурсів»;*
вул В'ячеслава Чорновола, 12, м. Київ, 01135, Україна

[2] *ДП «Науково-дослідний інститут нафтогазової промисловості»*
Національної акціонерної компанії «Нафтогаз України»;
вул. Київська, 8, м. Вишневе, Київська обл., 08132, Україна

[3] *НДПІ ПАТ «Укрнафта»;*
Північний бульвар ім. Пушкіна, 2, м. Івано-Франківськ, 76019, Україна

Числове моделювання технологій водогазових репресій вимагає адекватного представлення залежностей відносних фазових проникностей для нафти, газу і води від насиченості колектора. На основі узгодження результатів числового моделювання з натурними експериментами виконано параметризацію функцій А. Корея для фазових проникностей еоценових пісковиків за нафтою, газом і водою після зниження тиску нижче тиску насичення. Встановлено зв'язки параметрів функцій з початковою газонасиченістю, що формується в результаті виділення з нафти розчиненого газу.

Ключові слова: *водогазова репресія, еоценовий пісковик, тиск насичення, фазові проникності, числове моделювання.*