Assessment of Non-Equilibrium Phase Behavior Model Parameters for Oil and Gas-Condensate Systems by Laboratory and Field Studies

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Abstract

Non-equilibrium phase behavior of hydrocarbons has a great influence on the development of gas condensate and oil and gas condensate deposits, as well as oil deposits after evolution of dissolved gas. The key parameter of mathematical models that take into account non-equilibrium phase behavior is the characteristic relaxation time. The paper presents examples of assessing its value according to the results of laboratory experiments and well tests, which also allow verifying the mathematical model and obtaining input data for the production forecast taking into account non-equilibrium processes.

A model of non-equilibrium phase behavior in a compositional formulation, based on relaxation of the chemical potentials difference, was verified on the data of a laboratory experiment in a calorimeter cell. The numerical algorithm for calculating the dynamics of phase fractions and compositions in a non-equilibrium process was modified to take into account the isochoric condition, which made it possible to directly compare the simulation results to the real experiment. A good match of the experimental pressure-temperature hysteresis curves was obtained without additional adjustment of the characteristic relaxation time as compared with the estimate obtained from processing the measured pressure relaxation curve. Thus, the adequacy of the mathematical model and the possibility of evaluating its parameters directly from the experimental measurements were confirmed.

An example of assessing the characteristic relaxation time from well test data is presented for the pressure buildup (PBU) curve recorded under the conditions of gas dissolution in oil. A sector blackoil-type model was used for the well drainage area. For matching the PBU data, various modeling methods for non-instant gas dissolution were considered, including a model based on relaxation of solution gas-oil ratio (sGOR). The results of simulations with the sector model showed that the traditional options for limiting the sGOR increasing rate do not allow adequate matching of the PBU curve under conditions of gas dissolution. For the model that takes into account the sGOR relaxation, an in-situ estimate of the characteristic relaxation time was obtained which provided a fine match of the PBU data. As expected from theoretical concepts, the characteristic relaxation time for the in-situ process has a much larger order of magnitude than for the laboratory experiments on centimeter-sized cells.

The results of the study show the adequacy of relaxation models for non-equilibrium phase behavior in compositional and black-oil formulations for describing real processes and demonstrate the possibility to estimate the characteristic relaxation time from laboratory experiments and well tests, taking into account its dependence on the process scale.

Introduction

Phase behavior modeling of hydrocarbon (HC) mixtures forms the basis for calculation of the state and properties of fluids in flow simulations and engineering calculations of reservoir processes, as well as in PVT modeling. The classical assumption of such models is the equilibrium nature of phase transitions (Brusilovsky, 2002). That is, it is believed that the time to establish thermodynamic equilibrium in an elementary volume is significantly less than the characteristic time of variations in pressure and mixture composition (and temperature in the non-isothermal case) for the process under consideration. This assumption in the case of compositional description of reservoir fluids is written in the form of equality conditions for the chemical potentials (or fugacities) of the components in phases. And in the case of pseudo-binary description (models of black-oil type with the components "separator oil / condensate" and "separator gas"), it is reduced to the possibility of setting the current saturated sGOR (or the condensate content in the gas phase) as a function of pressure (and temperature).

For relatively slow processes associated with the production and flow of fluids in the reservoir, these conditions are satisfied when the state of the system changes from single-phase to two-phase, that is, for evolution of gas in the oil system or retrograde condensation in the gas condensate system. Quick establishment of equilibrium is achieved by nucleating a new phase in the form of bubbles / drops in the volume of the existing phase. In the opposite direction, for gas dissolution or condensate evaporation, phase transitions proceed much more slowly, since they are associated with the diffusion of components through the formed interphase boundary (Indrupskiy et al., 2017). If such a non-equilibrium process is considered as the relaxation of the phases fractions and compositions in the mixture to their equilibrium values, then the characteristic relaxation time is a parameter characterizing its duration.

Thus, there is a phase transition hysteresis: the characteristic relaxation time is short (can be considered zero) for transitions from a single-phase to the two-phase state, but it can be significant for opposite situations. Moreover, it depends on the composition and properties of the fluid, reservoir properties, process characteristic and modeling scale (elementary volume) (Indrupskiy et al., 2017; Lobanova and Indrupskiy, 2012).

From practical point of view, the relaxation time determines, for example, the possibility of dissolution of the free (released) gas in oil or evaporation of the retrograde condensate. Therefore, it is fundamentally important for assessing the effectiveness of secondary and tertiary methods for HC recovery after decreasing pressure below the saturation point of the initial reservoir system (Brilliant et al., 2014; Danko et al., 2018).

In the subsequent sections of the paper, models for non-equilibrium phase behavior of hydrocarbons in compositional and pseudo-binary formulations and relation of their parameters to the characteristic relaxation time are described. Then examples of estimating the characteristic relaxation time from the results of laboratory experiments and well test, with verification of the models of non-equilibrium phase behavior, are considered. In each case, the corresponding approaches and algorithms are described. The estimates obtained are analyzed taking into account the expected influence of scale of the elementary volume on the characteristic relaxation time.

Non-equilibrium phase behavior models

In commercial software for compositional flow simulations and PVT modeling, equilibrium assumption is generally accepted. It is assumed that at each calculation step (and in every grid cell) the phase state and phase properties are determined from the phase equilibrium conditions: equality of temperatures, pressures

and chemical potentials (or fugacities) of the components in the coexisting phases. The resulting system of equations, after adding normalization conditions, is called the flash problem and allows determining the number, fractions, and compositions of coexisting phases for given temperature, pressure, and total composition of the hydrocarbon mixture (Whitson and Brule, 2000):

$$\begin{cases} ln f_{i,L} - ln f_{i,V} = 0, & i = 1..N, \\ x_i L + y_i V - z_i = 0, & i = 1..N, \\ \sum_{i=1}^{N} y_i - 1 = 0, \\ L + V = 1, \end{cases} \qquad (1)$$

where N is the number of components in the HC mixture; L and V are the molar fractions of the liquid and vapor phases, x_i and y_i are the compositions of the liquid and vapor phases (molar concentrations of component i in the phases), respectively; $f_{i,L}$ and $f_{i,V}$ are the fugacities of component i in the liquid and vapor phases at current pressure p and temperature T, related to the chemical potentials of this component in liquid $\mu_{i,L}$ and vapor $\mu_{i,V}$ phases as

$$\mu_{i,L} = RT \ln f_{i,L} + \mu_i^0, \; \mu_{i,V} = RT \ln f_{i,V} + \mu_i^0, \; i = 1..N, \qquad (2)$$

with R being the universal gas constant; μ_i^0 – chemical potential of component i in the ideal gas state at temperature T and unit pressure.

To take into account non-equilibrium phase transitions, two methods were proposed in (Indrupskiy et al., 2017; Bogachev et al., 2019) that generalize the classical formulation by replacing the phase equilibrium conditions by relaxation relations.

In (Indrupskiy et al., 2017), it was proposed for each step of the calculation, when the criterion for non-equilibrium phase transition is satisfied, to replace system (1) by relations:

$$\begin{cases} ln f_{i,L} - ln f_{i,V} = \bar{\omega}_{i,\,L-V}, & i = 1..N, \\ x_i L + y_i V - z_i = 0, & i = 1..N, \\ \sum_{i=1}^{N} y_i - 1 = 0, \\ L + V = 1, \end{cases} \qquad (3)$$

where all the quantities in the left hand side correspond to the current moment j, and the expression for $\bar{\omega}_{i,\,L-V}$ in the right hand side is:

$$\bar{\omega}_{i,\,L-V} = \left[\ln f_{i,L}\left(\vec{x}^{j-1}, p^j \right) - \ln f_{i,V}\left(\vec{y}^{j-1}, p^j \right) \right] \exp(-\lambda \Delta t). \qquad (4)$$

Here $\vec{x}^{j-1}$ and $\vec{y}^{j-1}$ correspond to the compositions of the liquid and vapor phases at the previous moment in time, and pressure p^j – at the current moment j; Δt is the time step; and λ is the reverse characteristic relaxation time.

The substitution of expression (4) in the right-hand side of equations (3) corresponds to the assumption of relaxation of the component chemical potentials difference towards the equilibrium (zero) value during the time step Δt, with a corresponding change in the fractions and compositions of the phases, following the change in pressure from p^{j-1} to p^j).

An alternative method based on relaxation of the distribution coefficients (K-values) of components $K_i = \dfrac{y_i}{x_i}$ was proposed in (Bogachev et al., 2019).

At each time step, the system (1) is first solved to determine the equilibrium K-values K_{i}^{*j}. To do this, system (1) is generalized to the region of single-phase states, where the obtained solution satisfies the

normalization conditions for a negative fraction of one of the phases – the so-called negative flash (Whitson and Michelsen, 1989).

Further it is assumed that the actual (non-equilibrium) K-values are relaxing during the time step Δt from K_i^{j-1} towards $K_{i\,j}^*$, so at the moment j

$$K_i^j = K_i^{j-1} + \left(K_{i\,j}^* - K_i^{j-1}\right)\exp\left(-\lambda\Delta t\right), \tag{5}$$

or assuming a small time step

$$K_i^j = K_{i\,j}^* - \lambda\left(K_i^* - K_i^{j-1}\right)\Delta t. \tag{6}$$

The obtained values K_i^j are used to compute current (non-equilibrium) phase fractions and compositions from normalizing conditions.

In black-oil type models, sGOR R_s and condensate content in the gas phase R_v play a role of component concentrations in the phases. We will consider specifics of phase behavior modeling for such models on the example of R_s.

The classical equilibrium formulation assumes that in the two-phase state of the hydrocarbon mixture, sGOR is a function of pressure: $R_s = R_s(p)$. This means that both the evolution and dissolution of the gas occur instantly, following the change in pressure.

To take into account non-instantaneous gas dissolution, the option of limiting the sGOR changing rate is available in commercial simulators:

$$R_s^j \leq D\Delta t + R_s^{j-1}, \tag{7}$$

where D is the input parameter, which corresponds to the maximum possible change of sGOR (in absolute units) over the unit step in time.

In (Zubov et al., 2015), it was proposed to use the solution of the relaxation equation for sGOR within the time step Δt instead of the engineering relation (7):

$$\frac{dR_s^j}{dt} = -\overline{D}\left(R_s^j - R_s^*(p^j)\right), \tag{8}$$

where $\overline{D}$ has the same meaning as λ in equations (4)–(6), and $R_s^*(p^j)$ is the equilibrium sGOR at p^j). Then the final expression for the change in sGOR over the timestep takes the form similar to (5)–(6).

Both in the methods (3)–(4) and (5)–(6) for compositional models, and in the relaxation method (8) for black-oil models, the control parameter is $\lambda = \overline{D}$, which is the reverse characteristic relaxation time: $\lambda = 1/t_{relax}$. If t_{relax} is small ($\lambda \rightarrow \infty$), then all the methods are reduced to the classical equilibrium calculations of the fractiona and compositions of the phases (or sGOR / condensate content). If t_{relax} is large ($\lambda \rightarrow 0$), then a change in pressure does not lead to a change in the fractions and compositions of the phases, which corresponds to the absence of interphase mass transfer, that is, the impossibility of gas dissolution or condensate evaporation. At the same time, it should be taken into account that since the relaxation conditions in the considered methods are expressed with respect to different control values, they lead to slightly different dynamics of the process parameters (Al-Jenaibi et al., 2019), and the differences should increase with increasing time step.

For practical application of the non-equilibrium models, it is important to estimate the characteristic relaxation time by means of laboratory and field data. Relevant examples are discussed below. They also make it possible to verify the adequacy of the non-equilibrium processes description using the mathematical models.

Estimation of the characteristic relaxation time for a three-component mixture from a calorimeter cell experiment

Currently, laboratory studies of reservoir fluids are carried out under equilibrium conditions, which is ensured by slow changes in thermobaric parameters and mixing of the mixture.

Therefore, to verify the model and estimate the characteristic relaxation time, the data of specialized research studies performed earlier by the laboratory of Phase Transitions and Critical Phenomena named after E.E. Gorodetsky at OGRI RAS were used (Gorodetskii et al., 2005). The experiments were carried out with an adiabatic calorimeter, in a fixed-volume cell.

In the experiments, the HC mixture with given composition z_i was placed in the cell at an initial temperature T_{start}, corresponding to the single-phase state of the mixture. Density of the mixture ρ, which remains constant during the experiment, was determined from known mass of the mixture. Then the cell was gradually cooled down with a given rate of temperature change, and the isochoric p-T (pressure-temperature) dependence was determined upon cooling. From the characteristic kink on the isochore, the phase transition temperature T_{trans} was determined. Since the transition from a single-phase state to the two-phase state is equilibrium, this temperature corresponds to an equilibrium phase transition. Cooling of the cell, with the two-phase state of the mixture and equilibrium process dynamics, was continued until the minimum temperature T_{min} was reached.

Further, the cell was heated back, starting from the temperature T_{min}, with the same rate of temperature change as during cooling. But since the heating corresponds to the transition of the mixture from the two-phase state to the single-phase state, it is characterized as non-equilibrium. The p-T diagram shows pronounced hysteresis. Both the shape of the isochore, without an evident kink, and the temperature of the transition to the single-phase state change. The magnitude of deviation of the isochore during heating from the isochore during cooling depended on the minimum cooling temperature T_{min} and the exposure time before heating.

If the heating of the mixture was stopped at the temperature of the equilibrium phase transition T_{trans}, pressure relaxation was observed, and the system returned to the equilibrium p-T isochore obtained upon cooling. Further heating showed no hysteresis.

Fig. 1 shows an example of a p-T diagram obtained in one of the experiments with a three-component mixture of the following composition: 50% (molar) methane, 35% propane and 15% pentane. The initial temperature T_{start}= 365K, the minimum temperature T_{min}= 300K. The equilibrium cooling process with a rate of 2K/hour is shown by the blue isochore in Fig. 1. A kink at 340.6 K corresponds to equilibrium transition from the single-phase to the two-phase state.

Non-equilibrium isochore for heating at the same rate of 2K/hour is shown in orange. For the case when heating was stopped at the equilibrium phase transition temperature of 340.6 K, pressure relaxation is shown by a red vertical line. The same process is shown in Fig. 2 as a graph of pressure versus time during relaxation. Upon further heating, the system showed equilibrium behavior corresponding to the upward movement along the red inclined line in Fig. 1 towards T_{start}.
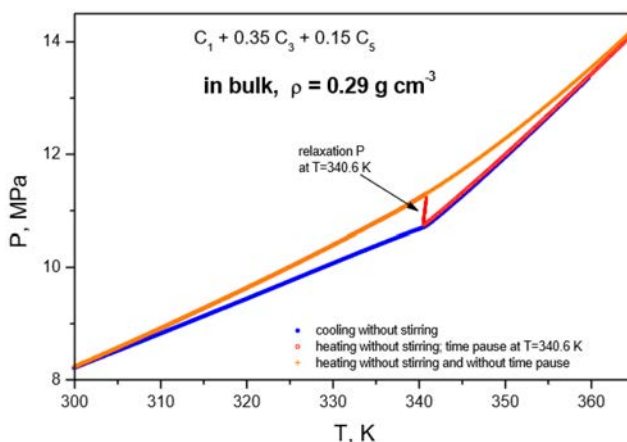
Figure 1—The *p-T* diagram for the isochoric experiment (Gorodetskii et al., 2005)
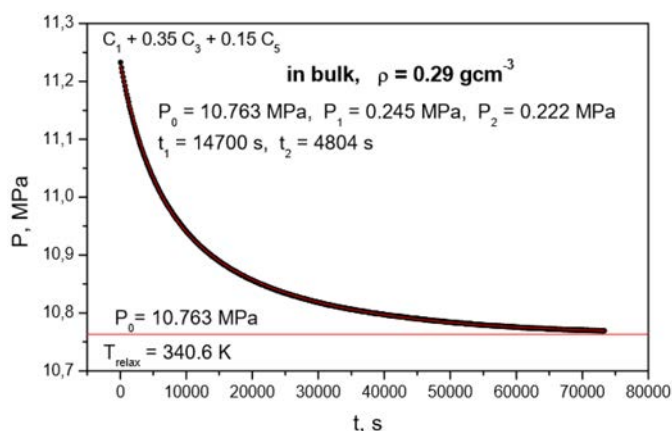

Figure 2—Graph of pressure relaxation at the temperature of equilibrium phase transition (Gorodetskii et al., 2005)

Values of t_1 and t_2 in Fig. 2 correspond to the processing of the pressure relaxation graph performed during the experiment with the expression

$$p(t) = P_0 + P_1 \exp(-t/t_1) + P_2 \exp(-t/t_2), \tag{9}$$

and during further modeling, the largest of the quantities was taken as the characteristic relaxation time – $t_1 = 14700$ s.

To simulate the experiment, the method based on relaxation of the chemical potentials difference was used. But since the experiment under consideration is isochoric, it required to make changes to the models described above. The problem is that both the equilibrium system (1) and the non-equilibrium system (3)–(4) assume independent changing of pressure and temperature at the steps of the experiment. In particular, these formulations are suitable for isothermal processes as a special case, when the temperature is constant and the pressure changes, which is most typical for oil and gas applications.

In an isochoric process, changes in pressure and temperature are not independent, but related by the condition of preserving the total volume (or density) of the mixture. In order to take into account the isochoric condition, systems (1) and (3) must be supplemented, for example, by the constant molar density equation. Combining together the equilibrium and non-equilibrium cases, we obtain the following system of equations for calculating the fractions and compositions of the phases in the isochoric process:

$$\begin{cases} lnf_{i,L} - lnf_{i,V} = \overline{\omega}_{i,\,L-V}, & i = 1..N, \\ x_i L + y_i V - z_i = 0, & i = 1..N, \\ \displaystyle\sum_{i=1}^{N} y_i - 1 = 0, \\ L + V = 1, \\ \rho_L u + \rho_V (1 - u) = \rho_0, \end{cases} \tag{10}$$

where ρ_L and ρ_V are the molar densities of the liquid and vapor phases; u is the volume fraction of the liquid phase, and $(1-u)$ – of the vapor phase; ρ_0 is the total molar density of the mixture, which is constant in the experiment.

To simulate the isochoric process, a system of equations (10) is solved at each time step with respect to the fractions and compositions of the phases, as well as the pressure, for the given total mixture composition and the temperature change at the step. The fugacities of the components in phases and the molar densities of phases are determined from the equation of state, for example, the Peng-Robinson equation (Whitson and Brule, 2000). The resulting system of nonlinear equations is solved by the Newton method (Aglyamova and Indrupskiy, 2019).

In the single-phase state of the mixture, system (10) is reduced to solving one last equation with respect to pressure at $u=0$ or $u=1$, which for a given temperature can be done by the successive substitution method.

In the case of equilibrium process, $\overline{\omega}_{i,\,L-V} = 0$ in (10). In the non-equilibrium case, it is necessary to make some changes to expression (4) in order to take into account the specifics of the isochoric process. Considering the temperature as an independent external parameter, and the pressure as a dependent via the isochoric condition, the final expression can be represented in the form (Aglyamova and Indrupskiy, 2019):

$$\overline{\omega}_{i,\,L-V} = \left[\ln f_{i,L}\left(\vec{x}^{\,j-1}, \tilde{p}^{\,j-1}, T^j\right) - \ln f_{i,V}\left(\vec{y}^{\,j-1}, \tilde{p}^{\,j-1}, T^j\right) \right] \exp\left(-\lambda \Delta t\right). \tag{11}$$

Here $\tilde{p}^{\,j-1}$ corresponds to the "intermediate" value of pressure, which ensures preservation of the total molar density of the mixture ρ_0 at the new temperature T^j, but keeping the previous phase fractions L^{j-1}, V^{j-1} and their compositions $\vec{x}^{\,j-1}$, $\vec{y}^{\,j-1}$. The successive substitution method is also used to determine $\tilde{p}^{\,j-1}$.

Thus, successively changing the temperature values in accordance with the time step and the heating rate, and solving system (10) at each step taking into account expression (11), it is possible to determine the changes in the fractions and compositions of the phases, as well as the pressure, during the non-equilibrium isochoric process. At a fixed temperature, the solution of system (10) with the expression (11) for successive time steps provides calculation of the pressure relaxation curve.

Fig. 3 shows a comparison of the experimental p-T diagram from Fig. 1 and calculated diagram obtained using the described isochoric algorithm. The solid lines show the experimental dependences, and the circular markers show the calculated results. The blue line corresponds to the equilibrium process when the mixture is cooled, the red line – to the non-equilibrium process when the mixture is heated. It can be seen that, in general, a good agreement was achieved between the experimental data and the simulation results. In particular, the general shape of the hysteretic diagram and the deviation of the non-equilibrium curve from the equilibrium one were correctly reproduced. In this case, the value of λ was set equal to $1/14700$ s^{-1}, i.e., it corresponds to the experimentally estimated characteristic relaxation time and did not require additional correction. Some deviation of the calculated diagram from the experimental one in Fig. 3 is manifested both on the non-equilibrium and equilibrium isochores. It is associated not with the behavior of the non-equilibrium model, but with inaccuracies in calculating the density of the mixture using the equation of state.

The influence of the relaxation time on the shape of the p-T diagram is shown in Fig. 4. When the value of $t_{relax}=1/\lambda$ is set higher than accepted in Fig. 3, the non-equilibrium isochore goes farther from the equilibrium

one, and the magnitude of the hysteresis increases. When the characteristic relaxation time is underestimated (λ is overestimated), the non-equilibrium isochore approaches the equilibrium one.
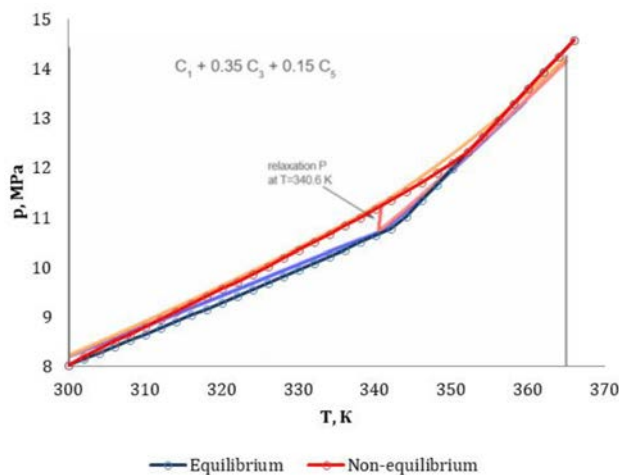

Figure 3—Experimental (solid lines) and calculated (circle markers) *p-T* diagrams for the experiment
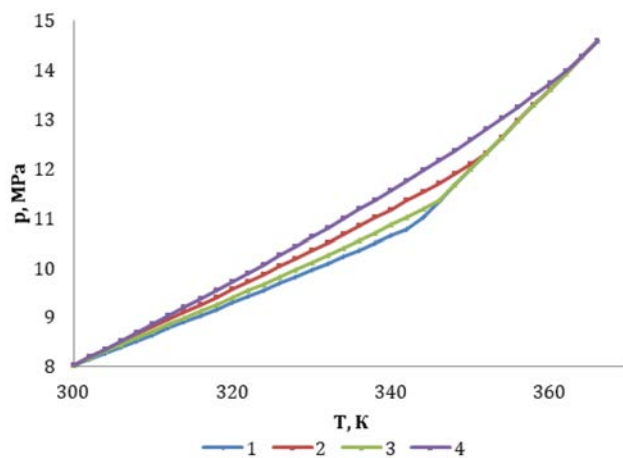

Figure 4—Calculated *p-T* diagrams for various values of t_{relax} = 1/λ: 1 – equilibrium; 2 – 14700 s; 3 – 7000 s; 4 – 50000 s

Thus, the correct matching of the experimental hysteresis magnitude in Fig. 3 by the model one indicates the adequacy of the relaxation time value used in the model.

Fig. 5 compares the experimental (according to Fig. 2) and calculated isochoric pressure relaxation curves at the temperature of the equilibrium phase transition. The graphs show similar but not identical behavior, with a faster decrease in the experimental curve in the initial section. This is explained by the presence of a "faster" exponential term in the experimental expression (9) and is most likely due to the superposition of the influence of interphase mass transfer processes for different components of the mixture.
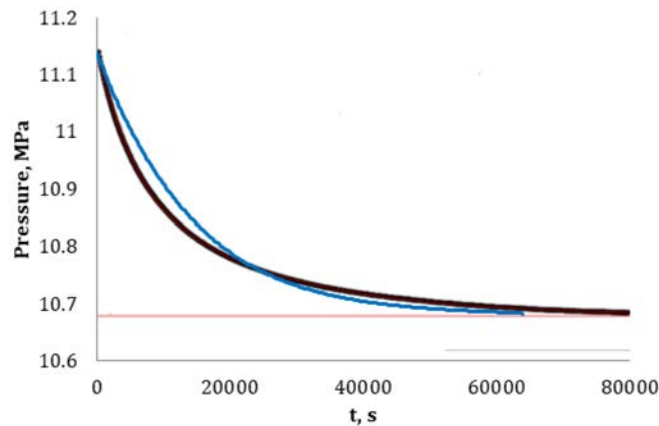
**Figure 5—Calculated (blue line) and experimental (brown line) pressure
relaxation curves at the temperature of equilibrium phase transition**

In general, Fig. 3–5 show that the model used and the value of the characteristic relaxation time determined directly from the experimental pressure relaxation curve ensure the correct reproduction of the general dynamics of the non-equilibrium process.

We also note that the obtained estimate of the characteristic relaxation time of 14700 s, i.e., a little higher than 4 hours, corresponds to the scale of the calorimeter cell – the first units of centimeters. In other similar experiments with two and three-component mixtures carried out both in bulk and in artificial porous media, this estimate varied in the range from units to the first tens of hours (Gorodetskii et al., 2005).

Estimation of relaxation time during gas dissolution by PBU data

It is known that the evolution of dissolved gas in the vicinity of an oil well when the pressure falls below the saturation pressure leads to deformation of the IPR curve due to a decrease in the permeability to oil. This behavior reflects the equilibrium transition of the reservoir HC mixture from the single-phase state to the two-phase state.

The process of gas dissolution with increasing pressure is reflected in the reverse IPR curve, which in such cases demonstrates pronounced hysteresis (Usenko, 1967; Kornaeva, 2015). One of key reasons for such behavior is the non-equilibrium (non-instantaneous) nature of the reverse phase transition of the HC system to the single-phase state. This effect also manifests itself in the PBU data, in the form of a prolonged period until the radial flow is reached.

Let us consider, as an example, the PBU recorded in a well completed in an ultralight oil reservoir with high sGOR (849.2 m^3/tonn), and a saturation pressure of 49.46 MPa close to the initial reservoir pressure of 52.7 MPa. The PBU was recorded within 49 hours after long-term operation with bottomhole pressure significantly lower than the saturation pressure, which led to gas evolution and long period until the radial mode was reached. The kind of pressure behavior cannot be reproduced within the framework of standard PBU interpretation models. As an illustration, Fig. 6 shows an attempt to match the actual bilogarithmic graph of pressure deviation and its logarithmic derivative with the model graph taking into account the influence of the wellbore storage and the dependence of the skin effect on the flow rate. It can be seen that the nature and duration of the "hump" on the actual derivative curve corresponds to a fundamentally different process.
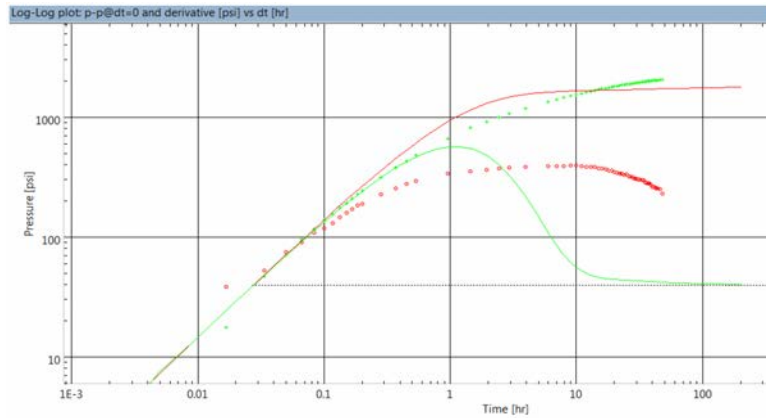
Figure 6—Model (solid lines) and actual (points) dynamics of the pressure deviation (red line, green points) and its logarithmic derivative (green line, red points) in bilogarithmic coordinates

To simulate the actual reservoir processes taking into account gas evolution and reverse dissolution, a layered sector flow model of the well drainage area was used with power-law increasing grid cell sizes in horizontal directions from 0.02 m at the well to 3000 m. Properties of the layers were specified using the well log interpretation results. Permeabilities of the layers and the initial pressure were adjusted to match the parameters estimated from the PBU in the same well reaching the radial flow.

Simulations with the sector model, with equilibrium dependence of sGOR on pressure, made it possible to match the bottomhole pressure drawdown curve at the start of well operation and the pressure dynamics during operation before the well was stopped for the PBU. But the PBU curve itself couldn't be reproduced with the equilibrium model due to the instantaneous gas dissolution with increasing pressure, which led to too rapid restoration of oil permeability.

The traditional option for limiting the gas dissolution rate (7) also did not provide the correct dynamics of pressure during the PBU. The reason was in the constancy of parameter D, while the absolute rate of sGOR change should decrease as the system relaxes toward equilibrium. Fig. 7 shows that different sections of the PBU curve can be roughly approximated by an artificial change in the sGOR dependence on pressure during gas dissolution, that is, by controlling the deviation of the non-equilibrium sGOR from the equilibrium sGOR in time. This means that the balance between the change in the non-equilibrium sGOR and the pressure increase rate varies in time, which is not taken into account by relation (7).
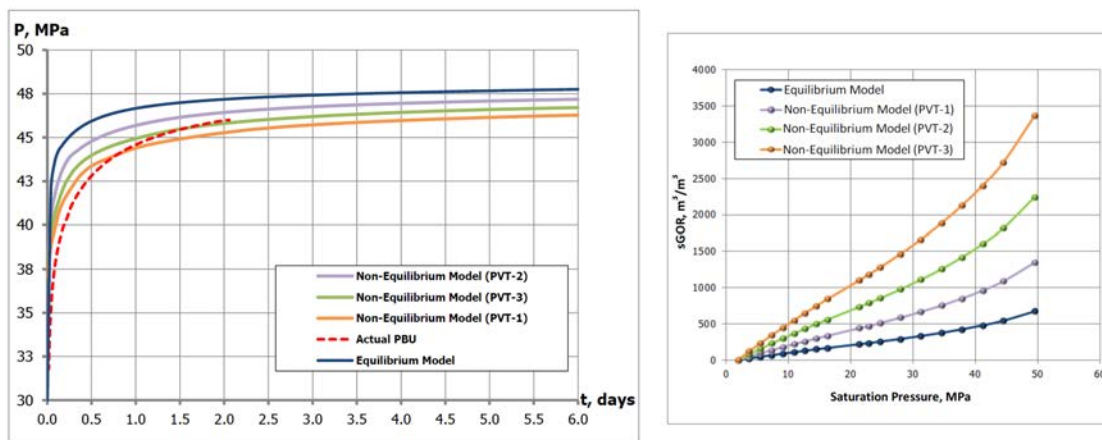

Figure 7—Approximation of the actual PBU data by the simulated ones (left) using various dependences of sGOR on pressure for gas dissolution (right). The equilibrium model corresponds to using the same curves during gas evolution and dissolution

Fig. 8 shows the result of successful matching of the actual PBU curve using the relaxation model (8) for changes in sGOR during non-equilibrium gas dissolution, in comparison with the simulated curves according to the equilibrium model and the model based on relation (7) with D=10 m³/m³/day. The obtained value of $\overline{D}$ in equation (8) corresponds to a characteristic relaxation time of ~ 1000 days. This value is in agreement with the analysis of the characteristic relaxation time dependence on the process description scale presented in (Indrupskiy et al., 2017). However, it can be noted that the simulated PBU curves for the equilibrium and non-equilibrium models reach similar values after about 6 days.

The apparent discrepancy is explained by the following reasons.

− Gas dissolution during the real process lasts much longer than 6 days, which is confirmed by the dynamics of gas saturation changes in the sector model. However, since the relaxation process corresponds to an exponential dependence on time, the degree of its influence on the pressure curve decreases rapidly.
− The characteristic relaxation time corresponds to the process of gas dissolution at constant pressure. In the case of PBU, the pressure increases rapidly, so the same degree of proximity to the equilibrium curve is achieved much faster.
− By the time of 6 days, the pressure increase rate gets smaller by several orders of magnitude compared to the initial section of the curve. Accordingly, for a constant characteristic relaxation time, the difference between the non-equilibrium and equilibrium dynamics of gas dissolution also gets smaller by the same several orders of magnitude.

Thus, the example presented shows that the relaxation model (8) with the characteristic relaxation time estimated from PBU provides correct description of the non-equilibrium gas dissolution process and its effect on the pressure dynamics. But the resulting estimate should not be interpreted from a practical point of view as the time required for the process to get close to equilibrium.
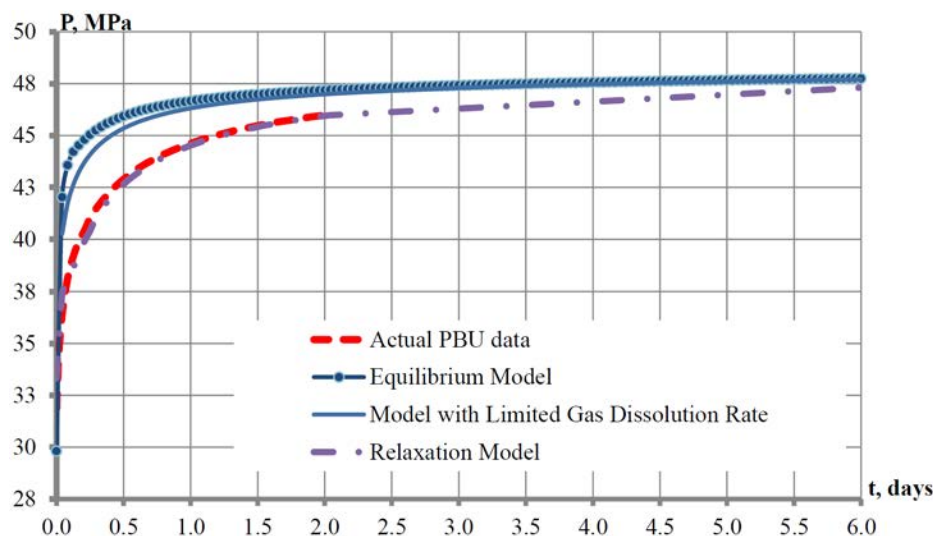

Figure 8—The result of matching the PBU curve with the relaxation model for sGOR during non-equilibrium gas dissolution

Conclusions

Non-equilibrium phase behavior takes place in many important processes in the development of petroleum reservoirs associated with mass transfer between the liquid and gas phases through the formed interphase boundary. In particular, it is typical for the dissolution of gas in oil and the evaporation of condensate to the gas phase.

To describe the processes with non-equilibrium phase transitions, several options have been previously proposed which extend the classical equilibrium models of both the compositional and black-oil types. Their common feature is the relaxation description of non-equilibrium effects. The key parameter of all considered models is the characteristic relaxation time.

This paper presented examples of estimating the characteristic relaxation time for two different processes and two models of different types.

In the first example, a laboratory experiment in a fixed-volume calorimeter cell for a three-component hydrocarbon mixture was considered. For simulation, a compositional model and a method for calculating non-equilibrium phase transitions based on relaxation of the chemical potentials difference, generalized to the isochoric case, were used. The characteristic relaxation time is estimated from direct processing of the experimental pressure relaxation curve. It is shown that the model correctly reproduces the experimental results without additional tuning.

In the second example, the PBU curve obtained in an oil well after intensive gas evolution during well operation was presented. A black-oil type model was used. The specific features of non-equilibrium gas dissolution on the PBU curve and the impossibility of matching it with standard interpretation and simulation tools were demonstrated. The use of a model based on relaxation of sGOR provided a good agreement between the simulated and actual PBU data. The characteristic relaxation time was estimated.

Due to the significant difference in the scale of the processes in the two examples, the estimates of the characteristic relaxation time have fundamentally different orders of magnitude. However, they are consistent with the expected scaling of the parameters of non-equilibrium phase transitions.

Thus, the relaxation models in the compositional and black-oil formulations make it possible to adequately describe processes with non-equilibrium phase transitions at the laboratory and field scales and provide an opportunity to estimate the characteristic relaxation time taking into account the scale of the process description.

Acknowledgements

Units

1 Psi = 0.069 bar = 0.0069 MPa

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