Article

Conditions for Effective Application of the Decline Curve Analysis Method

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Abstract: Determining the reliable values of the filtration parameters of productive reservoirs is the most important task in monitoring the processes of reserve production. Hydrodynamic studies of wells by the pressure build-up method, as well as a modern method based on production curve analysis (Decline Curve Analysis (DCA)), are some of the effective methods for solving this problem. This paper is devoted to assessing the reliability of these two methods in determining the filtration parameters of terrigenous and carbonaceous productive deposits of oil fields in the Perm Krai. The materials of 150 conditioned and highly informative (obtained using high-precision depth instruments) studies of wells were used to solve this problem, including 100 studies conducted in terrigenous reservoirs (C_1v) and 50 carried out in carbonate reservoirs (C_2b). To solve the problem, an effective tool was used—multivariate regression analysis. This approach is new and has not been previously used to assess the reliability of determining the filtration parameters of reservoir systems by different research methods. With its use, a series of statistical models with varying degrees of detail was built. A series of multivariate mathematical models of well flow rates using the filtration parameters determined for each of the methods is constructed. The inclusion or non-inclusion of these filtration parameters in the resulting flow rate models allows us to give a reasonable assessment of the possibility of using the pressure build-up method and the DCA method. All the constructed models are characterized by high statistical estimates: in all cases, a high value of the determination coefficient was obtained, and the probability of an error in all cases was significantly less than 5%. As applied to the fields under consideration, it was found that both methods demonstrate stable results in terrigenous reservoirs. The permeability determined by the DCA method and the pressure build-up curve does not control the flow of the fluid in carbonate reservoirs, which proves the complexity of the filtration processes occurring in them. The DCA method is recommended for use to determine the permeability and skin factor in the conditions of terrigenous reservoirs.

Keywords: reservoir permeability; skin factor; pressure stabilization curve; Decline Curve Analysis; fluid flow rate; geological and technological parameters; multivariate mathematical models; and carbonate deposits

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1. Introduction

Determination of the reliable values of the filtration parameters for productive reservoirs is the most important task in monitoring the production processes at hydrocarbon reserves. One of the effective methods for solving this problem is hydrodynamic studies of wells by the pressure build-up method. Conducting such studies is mandatory for an enterprise engaged in oil production, and on the territory of the Russian Federation, conducting hydrodynamic studies of wells is regulated by state documents [1].

However, hydrodynamic studies of wells, as a method for determining the filtration parameters of productive formations, are characterized by some disadvantages. Firstly,

conducting research requires stopping wells, often for a very long time. In turn, a prolonged shutdown of wells leads to losses in the production of hydrocarbons, which is an unfavorable factor from an economic point of view (Table 1). In the conditions of oil production from low-permeable reservoirs, the pressure build-up process takes a long time, and the wells are put into operation without waiting for the full recovery of the bottom-hole pressure to the reservoir value [2]. For example, only in 10% of studies conducted at wells that operate low-permeability reservoirs in the Perm Region, the pressure in the well is completely restored. The use of modern software products, such as the Kappa Workstation software (Saphir module), for processing not fully recovered data, leads to difficulties, for example, in identifying a section of radial flow or other characteristic areas on diagnostic graphs [3,4].

Table 1. Loss of oil production during the hydrodynamic studies of wells.

Well	Duration of the Pressure Build-Up Period, Hour	Oil Flow Rate Before Stopping, Tons/Day	Oil Production Losses, Tons
1	186.6	3.8	709.1
2	283.6	17.0	4821.2
3	427.7	2.3	983.7
4	106.4	65.5	6967.3
5	119.1	58.5	6967.3
6	125.1	47.0	5879.7
7	426.6	26.1	11,134.3
8	576.6	36.7	21,161.2
9	429.0	1.0	429.0
Total loss of oil production for 9 wells			59,052.8

Moreover, conducting hydrodynamic studies is often accompanied by technological problems. For example, with the significant content of paraffins in the extracted oil, they can be deposited on the surface of the downhole deep equipment and form plugs. As a result, it is difficult to put the well into operation after the study [5]. Another technological problem is the low resolution of deep measuring devices and the inability to accurately register pressure at low rates of its increase, which is a common situation for low-permeability reservoirs [3].

In this regard, the task of practical application of methods for determining the filtration parameters of productive formations that do not require a long stop of wells and exclude the manifestation of the complicating factors listed above is urgent.

Currently, the method of determining the filtration parameters of productive formations based on the analysis of production is widely used in world practice [3,6,7].

Decline Curve Analysis (DCA) is a kind of analysis implemented in the Topaze module of the KAPPA Workstation software, which is currently one of the most frequently used in petroleum engineering [8,9]. This method is empirical and is used to evaluate the production of carbon-hydrogen, as well as to determine the filtration parameters of the reservoir and its state (skin factor). To implement this method, it is necessary to use the values of the well fluid flow rate for a long period of its operation (preferably for a month or more). A significant advantage of DCA is that this method does not require additional technical and technological solutions or economic investments [10,11]. Accumulation of measurements of bottom-hole pressure and well fluid flow can be the basis for hydrodynamic monitoring and allow for a correct analysis of the dynamics of changes in reservoir pressure over time for almost the entire fund of producing wells. It is worth highlighting the disadvantages of this method, which are noted in a number of works [12–14]: (1) the Arps drop curve is a classical DCA model, but it can only be used for granular-type reservoirs (it assumes a constant bottom-hole pressure and skin factor, as well as a constant well supply circuit; i.e., stable operation of neighboring wells); (2) the Fetkovich model is used for unsteady modes and modes of influence of boundaries, but production must be carried out at a constant pressure, and the well supply area and

the condition for the stability of the skin factor values over time must be observed; (3) the exponential decline model (SEPD) can simulate a non-stationary flow, but a sufficiently long production history is required for a qualitative assessment of the parameters (preferably from the beginning of well operation); (4) the model of the decline curve for the linear flow regime requires the use of a series of permeabilities of the collector matrix, which is difficult to determine; (5) the Duong model is used for reservoirs of a complex structure characterized by low permeability, but there are difficulties in predicting the parameters of rocks characterized by the presence of fracturing and cavernosity; (6) DCA is based on the data of constant bottom-hole pressure and operating conditions (drainage areas), but the variability (significant fluctuation) of these parameters over time (“noise” of neighboring wells, etc.) and the impact on the quality of the data obtained has not been evaluated by anyone at the moment [15]; and (7) significant variability and uncertainty of the filtration modes that characterize complex reservoirs (multilayer deposits; deposits with the presence of double and triple voidness) are not taken into account in the DCA method [16].

Analyzing the experience of using the modern DCA method, it is worth noting that an increase in the monitoring time with an increase in information content inevitably entails an increase in the number of influencing factors [17–19]. A number of parameters that are traditionally assumed to be constant during one-time hydrodynamic studies of wells become dynamic, thereby complicating the process of interpretation and justification of the results obtained. Uncertainties in the degree of reliability of their results and the physical meaning of the calculated parameters should be considered as problems of the mass application of the DCA method.

Thus, the assessment of the reliability and feasibility of using the DCA method to determine the spectrum of hydrodynamic parameters of carbon–hydrogen deposits in their individual geological and physical conditions is an urgent task, to the solution of which the paper is devoted.

The new approach presented in the article consists of the sequential implementation of the following algorithm:

- collection and systematization of field data—actual values of geological and technological indicators;
- processing of research data (pressure recovery curve and DSA);
- correlation analysis with an assessment of the statistical relationship of the predicted parameter (permeability and skin factor) with other geological and technological indicators;
- multivariate regression analysis with the construction of statistical models for forecasting production rates.

2. Materials and Methods

The method based on mining analysis (DCA) is implemented in the Kappa Workstation software (Topaze); its application makes it possible to determine the important hydrodynamic parameters, such as reservoir permeability and skin factor. It should be noted that production analysis is an indirect method for determining these parameters; it is obvious that the assessment of the method applicability should be based on a comparison of its results with the materials of direct measurements. However, direct measurements of the skin factor values are not possible [20]. Direct measurement of permeability is possible only with a core study, but it is incorrect to compare the core permeability with the permeability according to hydrodynamic studies [21–23]. In this regard, a different approach is needed to assess the applicability of the DCA method.

The following idea is proposed in this paper. Hydrodynamic studies using the pressure build-up method is considered another indirect but common method often used in practice for determining permeability and skin factor. The main idea of the used approach is as follows. It is known from the theory of underground hydromechanics that the filtration parameters of productive formations significantly affect the flow of fluid and, as a result, can be used as input data in individual models for determining the flow rates of wells.

Thus, the construction of a series of individual models of well flow rates, including the hydrodynamic parameters determined by one or another research technology, and the assessment of their performance will allow solving the problem. Reliable should be considered those parameters that, being substituted into the equation, make it possible to achieve the maximum correspondence of the calculated (model) flow rate to its actual value. The paper presents a comparative analysis of the permeability and skin factor values determined by the methods of DCA and pressure build-up. The materials of 150 conditioned and highly informative (obtained using high-precision depth instruments) studies of wells were used to solve this problem, including 100 studies conducted in terrigenous reservoirs (C_1v) and 50 carried out in carbonate reservoirs (C_2b). It should be noted that only high-quality studies using the pressure build-up curve method were used in the course of the research, as far as they are characterized by complete pressure build-up and unambiguously performed interpretation in the Kappa Workstation software (Saphir module). However, the pressure build-up curve method is also an indirect method, so a simple comparison of two indirectly determined values of the skin factor and two values of permeability is not the optimal way to solve the problem. It is necessary to perform a comparative analysis of the complex (joint) influence of these parameters together with other geological and technological characteristics on the processes of hydrocarbon filtration.

A multiple regression analysis is the optimal method for studying the complex joint influence of several variables on any value; it is used in this paper as the main tool for solving the problem. The predicted parameter (dependent factor) when constructing multiple regression equations was chosen based on the following considerations. It is known from the theory of oil field development that the filtration parameters of productive formations (including permeability and skin factor) significantly affect the flow of the fluid; that is, the flow rate of the well. Thus, the construction of a series of well flow rates individual models, including the hydrodynamic parameters determined by the methods of the pressure build-up curve and DCA, and a comparative analysis of their performance will solve the task.

To build multivariate models—multiple regression equations—it is necessary to select a list of parameters that will be used as input data. In addition to the values of permeability and skin factor determined by the DCA methods and the pressure build-up curve, the following geological and technological characteristics of each well studied were used in the work (see Abbreviation).

After collecting and systematizing the initial data, a multivariate correlation and regression analysis was performed.

At the initial stage, correlation analysis is performed; it includes studies that allow us to detect the dependence between several random variables. Within the framework of these studies, the Pearson correlation coefficient (R) was calculated, which characterizes the closeness of the relationship between the field parameters and reservoir pressure, as well as between the parameters. The results of calculating the correlation coefficients are presented in the form of a correlation matrix. The correlation coefficients between the values are presented in this matrix at the intersection of the corresponding rows and columns. For each of the calculated values of the correlation coefficient, a conclusion about the significance is obtained. The significance of the correlation coefficient was estimated on the basis of Student's t -test, using a significance level of $\alpha = 0.05$.

Next, using stepwise regression analysis, a multivariate model of the fluid rate was constructed using the known values of the geological–technological indicators of well operation, as well as the permeability and skin factor, certain methods of the pressure build-up curve and the DCA.

At the first step, the model includes an indicator that has the maximum impact on the predicted value (fluid flow rate). At the second step, the model includes an indicator that has a smaller impact on the predicted value than the first, but greater than all other indicators. Thus, all the indicators that have a significant impact on the flow rate of the liquid are consistently added to the model, and the model itself allows taking into account

the combined influence of all independent factors on the dependent variable [24–27]. When each of the indicators is included in the model, its contribution to the resulting coefficient of determination is estimated—an indicator of the reliability of the model. As a result of the analysis of the obtained model, it is possible to determine which parameters have a predominant effect on the flow rate of the liquid in the individual geological and technological conditions of the oil deposits under consideration.

It should be noted that the constructed model allows you to solve the target problem only if the source data corresponds to the range of changes in the parameters used in the construction of the model. Therefore, the ranges of its applicability are given for each of the models.

For each of the constructed models, statistical characteristics are calculated, according to which its reliability can be estimated: the coefficient of multiple correlation (determination) R and its significance level p , as well as the standard error of calculations S_0 . The calculations used standard algorithms used in well-known software products, for example, Statistica. A sign of high reliability was a value of $p < 0.05$ and the minimum value of the standard calculation error S_0 . The visual evaluation of the constructed models was performed by analyzing the correlation field between the actual and model (calculated) values of the fluid flow rate [28–31].

Furthermore, for each model, an analysis of what parameters are used in it and what is the sequence number of their inclusion was performed. It is believed that the factors located in the first places in the resulting multivariate equation make the greatest contribution to the formation of the predicted value. This analysis will allow us to determine which factors have the greatest influence and control the flow rate of the liquid under the conditions under consideration (in terrigenous and carbonate reservoirs).

Thus, the assessment of the applicability of the DCA method is based on the construction of multivariate models of the fluid flow rate for wells in terrigenous and carbonate reservoirs. Further, these models are compared with the models constructed using the results of the pressure build-up curve method. Methods should be considered reliable if their results are included in the multivariate models of accounts receivable, and the models themselves are statistically significant. Conversely, if a statistically significant multivariate model of the fluid flow rate is constructed for any conditions, but it does not use the results of the methods under consideration as an independent variable, then these methods should not be used.

3. Results

When using the values determined during the processing of the pressure build-up curve (pbc) as filtration parameters, the multivariate model of the fluid flow rate has the following form:

For terrigenous reservoirs:

$$Q_{\text{liquid}}^{\text{m} - \text{pbc}} = 25.111 + 0.49297W + 7.63712k_{\text{pbc}} + 0.46862S_{\text{pbc}} + 1.05483h - 0.01913N_{\text{ob}} - 0.13883\mu_{\text{oil}} - 0.01395\text{GOR}. \quad (1)$$

at $R = 0.776$, $p < 0.000001$.

The model was formed in the sequence given in the regression equation. The values of the coefficients R , describing the strength of statistical relationships, change as follows: 0.676; 0.709; 0.736; 0.746; 0.754; 0.761; 0.766.

For carbonate reservoirs:

$$Q_{\text{liquid}}^{\text{m} - \text{pbc}} = -44.996 + 0.084N_{\text{ob}} + 2.2159S_{\text{pbc}} - 0.3780\mu_{\text{oil}} + 0.9652h + 2.2225m + 2.3519\beta_s \quad (2)$$

at $R = 0.810$, $p < 0.00001$.

The model was formed in the sequence given in the regression equation. The values of the coefficients R , describing the strength of statistical relationships, change as follows: 0.553; 0.659; 0.691; 0.735; 0.756; 0.810.

When using the values determined during DCA processing as filtration parameters, the multivariate model of the fluid flow rate has the form:

For terrigenous reservoirs:

$$Q_{\text{liquid}}^{\text{m-DCA}} = -15.068 + 0.6312W + 83,966k_{\text{DCA}} + 0.3757S_{\text{DCA}} + 2.7350\beta_s + 1.3071h - 0.0182N_{\text{ob}} - 0.1395\mu_{\text{oil}} - 0.0160\text{GOR} \quad (3)$$

at $R = 0.804$, $p < 0.000001$.

The model was formed in the sequence given in the regression equation. The values of the coefficients R , describing the strength of statistical relationships, change as follows: 0.674; 0.737; 0.754; 0.766; 0.783; 0.791; 0.796; 0.804.

For carbonate reservoirs:

$$Q_{\text{liquid}}^{\text{m-DCA}} = -96.847 + 3.9706P_b + 1.0656h + 6.4705\beta_s + 0.2581W - 1.5860P_r + 1.7810m + 0.6472S_{\text{DCA}}. \quad (4)$$

at $R = 0.824$, $p < 0.000001$.

The model was formed in the sequence given in the regression equation. The values of the coefficients R , describing the strength of statistical relationships, change as follows: 0.572; 0.697; 0.723; 0.773; 0.801; 0.818; 0.824.

The correlation fields between the actual and model (calculated) flow rates are shown in Figures 1 and 2.

Figure 1. The correlation fields between the actual and model values of the liquid flow rates differentially depend on the values obtained when processing the data of the pressure build-up curve (a) and DCA (b) (terrigenous deposits) methods.

All the constructed models are characterized by a high statistical estimate: in all cases, a high value of the determination coefficient was obtained, and the probability of an error in all cases was significantly less than 5%. The analysis of the correlation fields (Figures 1 and 2), on which the calculated and actual flow rates are compared, also indicates the high reliability of the models.

The performed comparative analysis of the models built for terrigenous and carbonate reservoirs showed their significant difference. So, in all models built for terrigenous reservoirs, at the first step, the water cut of the production is included, while in models for carbonate reservoirs, this parameter is either not used at all or is present at the final positions. At the same time, the model for carbonate reservoirs includes indicators of the energy state—reservoir and bottomhole pressure; in models for terrigenous reservoirs,

these parameters are not used at all. The findings indicate a difference in filtration processes in reservoirs of different types, which corresponds to the concepts of the theory of underground hydromechanics.

Figure 2. The correlation fields between the actual and model values of the liquid flow rates differentially depend on the values obtained by processing the data of the pressure build-up curve (a) and DCA (b) (carbonate deposits) methods.

4. Discussion

In the course of the performed studies, multivariate statistical equations of liquid flow rates are constructed. The models are constructed differentially for wells operating terrigenous and carbonate reservoirs of oil deposits in the Perm Region.

The flow rate models (1) and (3) constructed for terrigenous reservoirs are characterized by a similar appearance. The permeability and the skin factor, determined both by the DCA method and by the pressure build-up curve method, are included in the models in the first positions; their inclusion significantly improves the model, which follows from the analysis of the dynamics of the coefficient R during the construction of the models.

Thus, in terrigenous reservoirs, the DCA method demonstrates a similar high reliability in determining the permeability and skin factor, as well as the pressure build-up curve method.

The models constructed for the carbonate reservoirs (2) and (4) are also characterized by high reliability. However, the model constructed according to the DCA method (4) differs significantly in its appearance from the model constructed according to the pressure build-up method (2). The models do not use any permeability value; thus, not by the DCA method nor by the pressure build-up method, meaning the flow of oil to the wells in the carbonate reservoirs of the considered sites is not controlled by the permeability values as determined by the pressure build-up curve and DCA methods. The skin factor determined by the pressure build-up curve method is included in model (2) in the second position, which indicates its pronounced effect on the well flow rate. The DCA skin factor is also included in the model, but much later, at the last step; this indicates that the pressure build-up curve method allows you to more reliably determine the value of the skin factor than the DCA method.

The complex and different types of multivariate models of well flow rates (2) and (4) indicate the complexity of the processes occurring during the filtration of carbon monoxide in carbonate reservoirs.

Comparing the models constructed for terrigenous and carbonate reservoirs, it can be concluded that the indicators of the energy state of deposits—reservoir and bottom-hole

pressure—are used only in models for carbonate reservoirs; that is, reservoir and bottom-hole pressures are factors that determine the flow of liquid only into carbonate reservoirs. In turn, the main factor affecting the flow of liquid in terrigenous reservoirs is the water content of products.

Another conclusion follows from the comparison of models for terrigenous and carbonate reservoirs. Indicators such as the thickness of the reservoir are included earlier in the models for carbonate reservoirs compared to the models for terrigenous reservoirs. This conclusion is quite natural, because oil deposits in carbonate reservoirs are more often of the massive type, and the thickness values for them vary over a wider range than for reservoir-arch deposits in terrigenous reservoirs.

5. Conclusions

The research presented in this paper is aimed at solving an important problem—the mathematical justification of the possibility of using the DCA method to determine the skin factor and reservoir permeability in terrigenous and carbonate reservoirs.

The innovative approach used in this research to assess the applicability of the pressure build-up and DCA methods also made it possible to solve a problem that is relevant for the theory and practice of developing hydrocarbon fields, namely, to assess the individual fluid filtration conditions. For this purpose, the procedure for constructing production models and their final form was analyzed. The filtration conditions were also determined based on the set of parameters included in the constructed models, as well as the intervals and ranges of their inclusion under various conditions

The main tool for solving this problem is multivariate regression analysis. In the course of its application, a series of multivariate statistical models of liquid flow rates was built. The analysis of the constructed models allowed us to obtain a number of important conclusions:

- (1) For terrigenous reservoirs, both methods (the pressure build-up curve method and the DCA method) demonstrate approximately the same high reliability of determining the permeability and the skin factor. Accordingly, the DCA method is recommended for use in terrigenous reservoirs.
- (2) The permeability determined by the DCA methods and the pressure build-up curve does not control the inflow in carbonate reservoirs. The possibility of using permeability along with the pressure build-up curve and DCA for solving geological problems requires additional research.
- (3) The factors forming the inflow in terrigenous and carbonate reservoirs are different. In terrigenous reservoirs, the inflow is largely formed by waterlogging, and in carbonate reservoirs, by reservoir and bottom-hole pressures.
- (4) Multivariate regression analysis is an effective tool for solving various problems. In this paper, it provided the possibility of using the DCA method for determining the filtration parameters of productive reservoirs, which was shown to be mathematically justified, with the individual conditions for the inflow of hydrocarbons in terrigenous and carbonate reservoirs also compared.

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Abbreviations

Q_{liquid}	current flow rate of liquid, m^3/day
P_b	bottomhole pressure, MPa
P_r	reservoir pressure, MPa
W	water cut crude production, %
m	porosity, %
h	reservoir thickness, m
μ_{oil}	oil viscosity, cP
b	the volume ratio of oil
β_s	full compressibility of the system, $1/\text{Mpa} \cdot 10^{-4}$
GOR	initial solution gas–oil ratio R_s (or GOR), m^3/m^3
N_{ob}	the depth of the object, m
k_{pbc}	permeability defined by the data processing of the pressure build-up curve, D
S_{pbc}	in factor specified when processing the data of the pressure build-up curve
k_{DCA}	permeability determined in the processing of the production curve analysis data, D
S_{DCA}	skin factor determined when processing the data of the production curve analysis data

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