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M.O. Poliakov, V.V. Vasylevskyi

Method for assessing unevenness of cellulose insulation layers aging of power transformers winding

***Introduction**. Improving the methods of estimating the insulation aging of the oil-immersed power transformer windings is an urgent task for transformer condition monitoring systems. The **scientific novelty** of the work is to take into account the uneven distribution of temperature and humidity along the vertical axis of the winding in modeling the aging of insulation and to develop methods for determining the conditions under which the aging rate of insulation in the intermediate layer will exceed aging rate in the hottest layer. The **purpose** of the work is to evaluate the wear unevenness of cellulose insulation based on modeling the distribution of temperature and humidity along the vertical axis of the power transformer winding. **Methods**. The transformer winding is mentally divided into horizontal layers of equal height, the reduction of service life is calculated in parallel for all horizontal layers. Layer with the maximum degree of aging for the entire period of operation and storage of the transformer is recognized as determining the reduction in the service life of the insulation of the transformer as a whole. A model of the interaction of winding layers is developed, with determination of temperatures, humidity, relative rate of aging of each layer due to temperature and humidity as a function of traditional design parameters such as load, cooling temperature, heat capacity and thermal resistance of transformer. The index of exceeding the aging rate by the layered method in comparison with this rate for the hottest layer is offered. The method of genetic algorithms determines the conditions for obtaining the maximum value of this index. **Results**. A computer model has been developed to predict the aging of the cellulose insulation of transformer windings. According to the proposed method, a layer with significantly shorter insulation aging time (in the example, time reduced by 39.18 %) than for the upper layer was determined, which confirms the feasibility of layer-by-layer monitoring and modeling of insulation aging processes of power oil-immersed transformer windings.* References 25, tables 2, figures 4.

Key words: **power oil-immersed transformer, cellulose insulation aging, computer model of layer-by-layer aging of winding insulation.**

***Вступ**. Вдосконалення методик оцінки старіння целюлозної ізоляції обмоток силового маслонаповненого трансформатора є актуальним завданням для систем моніторингу стану трансформаторів. **Наукова новизна** роботи полягає в урахуванні нерівномірності розподілів температури та вологості вздовж вертикальної осі обмотки при моделюванні процесів старіння ізоляції та у розробці методики визначення умов, за яких швидкість зносу ізоляції у проміжному шарі буде максимально перевищувати швидкість у найбільш нагрітому шарі обмотки. **Метою** роботи є оцінка нерівномірності зносу целюлозної ізоляції на основі моделювання розподілу температури та вологості вздовж вертикальної осі обмотки силових трансформаторів. **Методи**. Обмотка трансформатора подумки розділена на горизонтальні шари рівної висоти, підрахунок скорочення строку служби виконується паралельно за усіма горизонтальними шарами, а шар, що має максимальний ступінь старіння за весь період експлуатації та зберігання трансформатору визнається найбільш ресурс витратним шаром, який визначає скорочення строку служби ізоляції трансформатора в цілому. Розроблена модель взаємодії шарів обмотки, з визначенням температур, вологості, відносної швидкості старіння кожного шару внаслідок дії температури та вологи як функції традиційних розрахункових параметрів, таких як навантаження, температура охолодного середовища, теплоємність та тепловий опір трансформатора. Запропонований показник перевищення швидкості скорочення строку служби пошаровим методом у порівнянні з цієї швидкістю для найбільш нагрітого шару. Методом генетичних алгоритмів визначені умови для отримання максимального значення цього показника. **Результати**. Розроблена комп'ютерна модель для прогнозування старіння целюлозної ізоляції обмоток. За запропонованою методикою визначено найбільш ресурс витратний шар зі значно меншим часом старіння ізоляції (у прикладі час зменшено на 39,18 %), ніж для верхнього шару, що підтверджує доцільність пошарового моніторингу та моделювання процесів старіння ізоляції обмоток силового маслонаповненого трансформатора.* Бібл. 25, табл. 2, рис. 4.

Ключові слова: **силовий маслонаповнений трансформатор, старіння целюлозної ізоляції, комп'ютерна модель пошарового старіння ізоляції обмоток.**

Introduction. The issues of assessing the technical condition of power transformers, including the aging of the cellulose insulation of oil-immersed power transformer windings, are invariably in the focus of research by the world energy community [1, 2]. As is known [3], the residual service life of cellulose insulation is determined by the time during which the degree of polymerization of cellulose molecules decreases to 250 units. In turn, the aging rate depends on a number of operational factors, the main of which is considered to be temperature.

The result of comparing the assessment of insulation aging for a particular transformer with the assigned resource determines the moment the transformer is decommissioned and the probability of a transformer failure when it continues to operate [4].

The state of oil-immersed power transformer insulation is determined by the following methods: by means of analyzing cellulose degree of polymerization [3]; by indirect methods, for example, by the presence of certain gases in transformer oil [5, 6]; by online monitoring of operating conditions [7, 8]; based on the statistics of transformer accidents [9]; by modeling the reactions of the transformer to the predicted changes in operating factors [10].

The advantage of the latter method for determining the state of power transformers insulation is the ability to take into account the predicted dynamics of external operating factors. Therefore, this method is discussed in more detail below.

Previous research. Modeling of cellulose insulation aging includes modeling the thermodynamic and moisture-dynamic processes in the transformer, as well as modeling the effect of these processes on the insulation aging rate.

Known thermodynamic models are built on the basis of various differential equations of the heat balance of the transformer, which use various transformer equivalent circuits [11, 12]. Solutions of these equations are found both by analytical methods [13] and by computer simulation [11, 14-16].

Thermal modeling techniques are based on dynamic analogies of electrical and thermal processes, Computational Fluid Dynamics (CFD) and Thermal Hydraulic Network Model (THNM). Models based on the first technique do not take into account the nonlinear dependences of transformer thermal parameters. Models based on the other mentioned techniques require large computing resources and expensive commercial software for implementation.

The basic model for assessing the rate of insulation aging is the Montsinger equation [17], which determines the instantaneous rate of relative thermal aging of the insulation. Integration of this rate in a certain time interval gives the value of thermal aging of the insulation in this interval. The corresponding expression is called the «aging integral». Over time, multipliers were added to the aging integral, taking into account the influence on the cellulose insulation aging rate of its humidity, as well as the acid number of transformer oil [9, 11]. In other studies [4], these factors are taken into account in the expression of the aging rate through the values of the activation energy E and the pre-exponential factor A, due to the influence of humidity, acids, and oxidation.

There are studies in which the influence of the humidity of cellulose insulation on the deterioration of its technical condition is experimentally confirmed [18, 19].

At the same time, the known models of insulation aging do not take into account the relationship between the temperature and moisture distribution in the winding insulation along its vertical axis. The intensity of transformer insulation aging is determined by the hot-spot temperature (HS) which is located in the upper part of the winding. Accordingly, it is assumed that the greatest service life reduction also occurs at the top of the transformer. On the other hand, the aging rate of cellulose insulation, in addition to temperature, is affected by the degree of cellulose humidity and the oxidation of transformer oil. It is known that the wettest spot, (WS) in an operating transformer is located in the lower part of the winding.

In [20], the concept of the most resource consumption spot (RCS) is introduced, it is shown that this spot may not coincide with the HS and WS spots, can change its position in the direction of the vertical axis of the winding depending on the dynamics of the load current of the transformer, humidity of cellulose insulation and other factors.

During the simulation of temperature and humidity distributions, the transformer winding with height H is mentally divided into N layers of the same height, as it shown in Fig. 1.

The number of layers is chosen in such a way that, within each layer, changes in temperature and humidity along the vertical axis of the winding can be neglected [20].

Winding layers are numbered from bottom to top. In this case, the n-th layer number ($1 \leq n \leq N$) characterizes the excess of the layer boundaries over the bottom of the winding. The excess of the upper h_{tn} and lower h_{bn} boundaries of the n-th layer is determined by the expressions:

$$h_{tn} = \frac{Hn}{N}; \quad h_{bn} = \frac{H(n-1)}{N}.$$

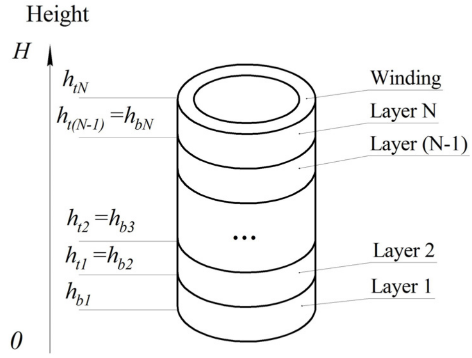

Fig. 1. Structure of the winding layers

Thus, in the case of a change in the value of N (for sufficiently large N), the excess of h will correspond to another layer. For example, with H = 2 m and N = 10, the point located at a height of 1.4 m lies on the boundary of the seventh, and with N = 20, the 14th layer.

Due to the oppositely directed temperature and humidity gradients in the layers, accelerated aging of the different winding layers at different points in time is possible.

Therefore, it is necessary to take into account the aging rate of the insulation for each layer and, by integration, determine the most aged layer since the manufacture of the transformer. It can be assumed that the aging of this layer determines the aging of the winding insulation as a whole.

It should be noted that in the layered model given in [16] there is no mechanism for the interaction of the processes of dynamic redistribution of temperatures and humidity of cellulose along the vertical axis of the winding. This, in turn, does not allow performing computer simulation of layer-by-layer aging of insulation under non-stationary load conditions of the transformer.

The purpose of this work is to evaluate the aging unevenness of cellulose insulation based on modeling the distribution of temperature and humidity along the vertical axis of the winding of power transformers.

The task of the work is to develop a computer model for calculating the reduction in the service life of winding insulation layers based on the current values of the transformer load, ambient temperature, winding humidity and thermodynamic parameters of the transformer, as well as to develop a methodology for determining conditions under which cellulose insulation aging in the intermediate layer is greater than in the layer with the hottest spot.

Layer-by-layer model of power oil-immersed transformers cellulose insulation aging. To solve the set tasks, a computer layer-by-layer thermo- and moisture-dynamic model of the transformer is proposed. The structure of the model is shown in Fig. 2. The model as a whole and its elements are external models (black box models), that is, models that establish the dependence of outputs on inputs without detailing the physical processes in the transformer and in its parts.

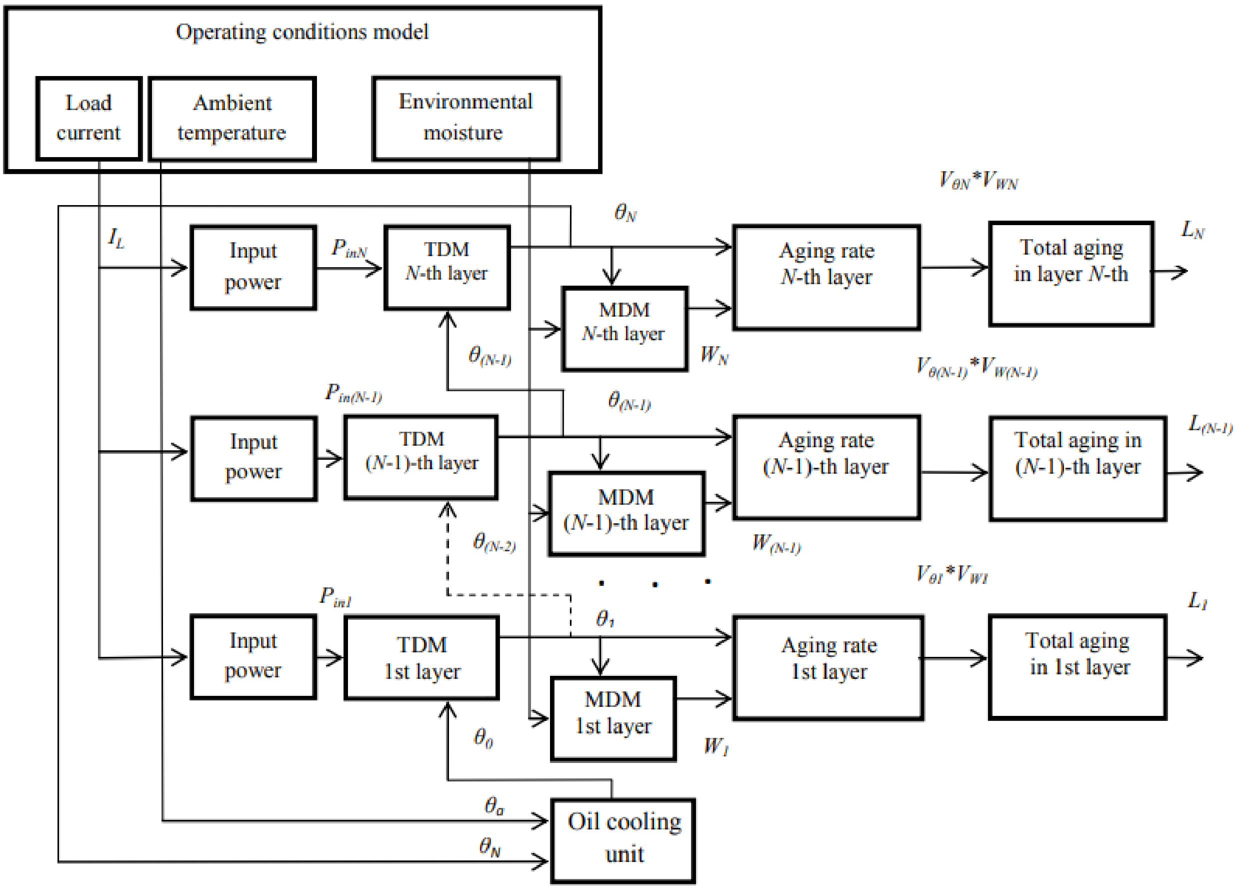

Fig. 2. Structural diagram of the layer-by-layer model of transformer winding insulation aging (TDM – thermodynamic model; MDM – moisture dynamic model)

The model consists of the unit for the formation of operating conditions, models of layers and units for determining the layer-by-layer insulation aging.

The operating conditions formation unit sets the values of the transformer load currents, the ambient temperature and the amount of moisture penetrating into the transformer tank. The layer model determines the input power, temperature and absolute humidity in the layer at the boundary of the «cellulose insulation-transformer oil» system. According to these data, the unit for determining the layer-by-layer aging of the insulation calculates the instantaneous rate of relative aging and the value of the aging of the cellulose insulation in the layer in accordance with the «aging integral» [4, 9-11].

Thus, the layer model consists of the input power model, thermodynamic and moisture dynamic models.

The input power of the n-th layer is determined from the expression [1]:

$$P_{n\,in} = \frac{P_{in}}{N} = \frac{I^2 Z + P_{il}}{N}, \qquad (1)$$

where P_{in} is the transformer power losses, W; I is the load current, A; Z is the winding resistance, Ω; P_{il} is the no-load loss, W; N is the number of layers.

The thermodynamic model of the n-th layer is based on the heat balance equation in the winding cellulose insulation layer immersed in transformer oil. In the proposed model, the differential equation of the first degree is chosen as the heat balance equation:

$$\frac{d\theta_n}{dt} = \frac{P_{n\,in}}{C_n} - \frac{1}{C_n R_n}\left(\theta_n - \theta_{(n-1)}\right), \qquad (2)$$

where θ_n, $\theta_{(n-1)}$ is the temperature of the n-th, $(n–1)$-th layer, °C; $d\theta_n/dt$ is the time derivative of the temperature of the n-th layer; C_n is the heat capacity of the n-th layer, J/K; R_n is the thermal resistance of the n-th layer, K/W.

A feature of the thermodynamic model of each layer is that it describes the thermal balance between the thermal power that is released in the layer winding as a result of the flow of load current and no-load losses and the thermal power that is transmitted through the moving oil to the overlying layers of the winding. Taking into account the direction of oil movement in the transformer tank from bottom to top, the thermal energy received by oil in the lower layer is involved in heating all layers of the winding. At the same time, the thermal energy released in the intermediate layer does not participate in the heating of the underlying layers of the winding. We also note that the oil heated in the N-th (upper) layer enters the cooler inlet, in which the oil temperature drops to the value θ_0 and contacts the lower layer of the winding.

To determine the values of parameters – heat capacity C_n, and thermal resistance R_n of the n-th layer, methods of comparing these parameters with the results of thermal tests or transformer condition monitoring were used [21].

The method takes into account the conditions (load current, ambient temperature, cooling modes) and the results (temperature of the upper layer of transformer oil, thermal constant of the transformer) of thermal tests. These parameters determine the requirements for the coefficients of the computer model of the heat balance equation of the transformer as a material point:

$$\frac{d\theta_m}{dt} = \frac{P_{m\,in}}{C_m} - \frac{1}{C_m R_m}\left(\theta_m - \theta_a\right), \qquad (3)$$

where $d\theta_m/dt$ is the time derivative of the top oil temperature; θ_m is the top-oil temperature, °C; θ_a is the ambient temperature, °C; $P_{m\ in}$ is the input thermal power (power loss), W; C_n is the heat capacity of the transformer, J/K; R_n – thermal resistance of the transformer, K/W.

The values of the equation coefficients of this model are chosen experimentally to ensure that the simulation results coincide, with a given accuracy, with the results of thermal tests.

If during transformer operation the current value of the thermal parameters changes over time, then it is advisable to use condition monitoring data to determine the thermal parameters. For this purpose, we substitute the results of measuring the top-oil temperature and the ambient temperature for two points in time into the heat balance equations (3). Then we solve the resulting system of algebraic equations with respect to the coefficients of the original differential equation – the heat capacity and thermal resistance of the transformer [21].

At the next stage, the equation (2) coefficients are expressed in terms of the equation (3) coefficients. The following assumptions are taken into account:

1. Top-oil temperatures in these models must be equal. I.e. $\theta_m = \theta_N$.

2. The lower layer inlet receives oil from the cooler outlet, which has a temperature θ_o. The moisture content of the oil in the cooler does not change.

3. The thermal resistance R_n of the section «cellulose insulation-transformer oil» in the layer model is expressed through the thermal resistance R_m of the transformer model as a material point:

$$R_n = R_m (N + 1 - n) / g\,, \qquad (4)$$

where (N+1–n) reflects the increase in thermal resistance R_n relative to the resistance R_m; g is an empirical coefficient that takes into account the decrease in the thermal resistance of the «winding layer-transformer oil» section of the layered model compared to the thermal resistance of the «top oil layer-environment» section of the «single point» model, which is used to adjust the layered model.

As follows from (4), when n increases, R_n decreases and, consequently, the dissipated power in the layer increases. This leads to a decrease in the power going to the heating of the layer substance and a decrease in the layer temperature increment.

4. The heat capacity of the layer and the thermal power that is released in the layer n is N times less than the corresponding values of the transformer model as a material point:

$$C_n = \frac{C_m}{N}\,; \qquad (5)$$

$$P_{n\,in} = \frac{P_{m\,in}}{N}\,. \qquad (6)$$

After substituting expressions (4) – (6) in (2) we get:

$$\frac{d\theta_n}{dt} = \frac{P_m}{C_m} - \frac{Ng}{C_m R_m (N + 1 - n)}\left(\theta_n - \theta_{(n-1)}\right). \qquad (7)$$

The temperature values θ_n of the n-th layer obtained as a result of application in the layer model are used to determine the absolute humidity, the rate of relative aging of the insulation of this layer and determine the temperature of the (n + 1)-th layer.

The moisture-dynamic model of the layer is based on the well-known method for calculating the degree of cellulose insulation humidity from the measured value of the relative humidity of transformer oil [22]. The calculated humidity of cellulose insulation of the n-th layer at a certain point in time is determined from the expression:

$$W(n) = A_w \cdot e^{-B_w \cdot \theta_n} \cdot p^{k_w + a_w \cdot \theta_n}\,,$$

where $W(n)$ is the calculated humidity of cellulose insulation of the n-th layer, %; A_w, B_w, k_w, a_w are the empirical coefficients [24]; θ_n is the temperature of the n-th layer of the transformer winding, (n = 1, N), °C; p is the partial pressure of water vapor, mmHg.

The value of the partial pressure of water vapor depends on the relative humidity of the transformer oil in the n-th layer at the corresponding temperature of this layer [24]:

$$p_{(n)} = \varphi' \cdot 10^{(8{,}0589 - 1729{,}9875/(\theta_n + 273{,}856))}\,,$$

where φ' is the relative humidity of oil at the temperature of the n-th winding layer θ_n, %.

Relative humidity at θ_n is determined from the expression [24]:

$$\varphi' = \frac{W_M}{C(\theta_n)}\,,$$

where $C_W(\theta_n)$ is the limiting humidity of oil at the temperature of the n-th layer, g/t; W_M is the absolute humidity of oil, taking into account the temperature of the n-th layer, g/t.

The value of the absolute humidity of transformer oil can be either determined by direct measurements or obtained empirically (for example, a value corresponding to a low degree of the oil humidity is taken). To take into account the dynamics of humidity in the system «cellulose insulation-transformer oil» due to changes in the thermal regime of the transformer, a model is used in the form of a state diagram [22]. This model is characterized by three states – moisture transfer from cellulose insulation to transformer oil, moisture transfer from transformer oil to cellulose insulation and an equilibrium state (is the initial one).

Thus, the moisture-dynamic model of the layer determines the absolute humidity in the layer based on the temperature value θ_n.

The oil at the outlet of the cooler has a moisture vapor pressure corresponding to the temperature of the upper layer. Therefore, moisture removed from the cellulose insulation in the top layer is returned to the cellulose insulation in the bottom layer. Similar processes occur in other layers, which together form the distribution of moisture along the vertical axis of the winding.

Simulation using the model on Fig. 2 was carried out for the conditions given in [22]. The initial data for setting up the model were the results of thermal tests of the transformer АТДЦН100000/220/150. During these tests, the transformer was placed in a climatic chamber, in which the temperature was maintained at θ_a = 40 °C and kept under a load of I_L = 244 A in a certain cooling mode for a time significantly longer than its thermal constant. In this case, the temperature θ_m of the upper oil layers was constantly measured. According to the measurement data, the temperature of the excess of the upper oil layers $\Delta\theta$ = 40 °C and the thermal time constant τ = 2.4 hours were established. Based on these data and the passport value of the no-load loss parameter P_{il}, the coefficients C_m, R_m of equation (3) were determined using the method [21, 25]. To solve equation (3), a computer model was used in the Simulink environment with the values of the input variables corresponding to the conditions of the thermal tests performed. The deviations of the values of τ and $\Delta\theta$ obtained as a result of modeling from the results of thermal tests do not exceed 5 %.

At the next stage, using this computer model, the temperature of the upper oil layers was determined for the conditions of the experiment with a layered model (Fig. 2): the load current I_L changed according to the profile shown in Fig. 3, and the temperature θ_a is taken equal to 40 °C. Further, the parameters of the layered model, in particular, the coefficient g, were selected in such a way (g = 11.11) that the temperature of the upper oil layers in the layered model was equal to the corresponding temperature of the original «one-point» model. After that, the temperatures obtained in the course of modeling using a layered model were used to determine the moisture distributions and aging rates.

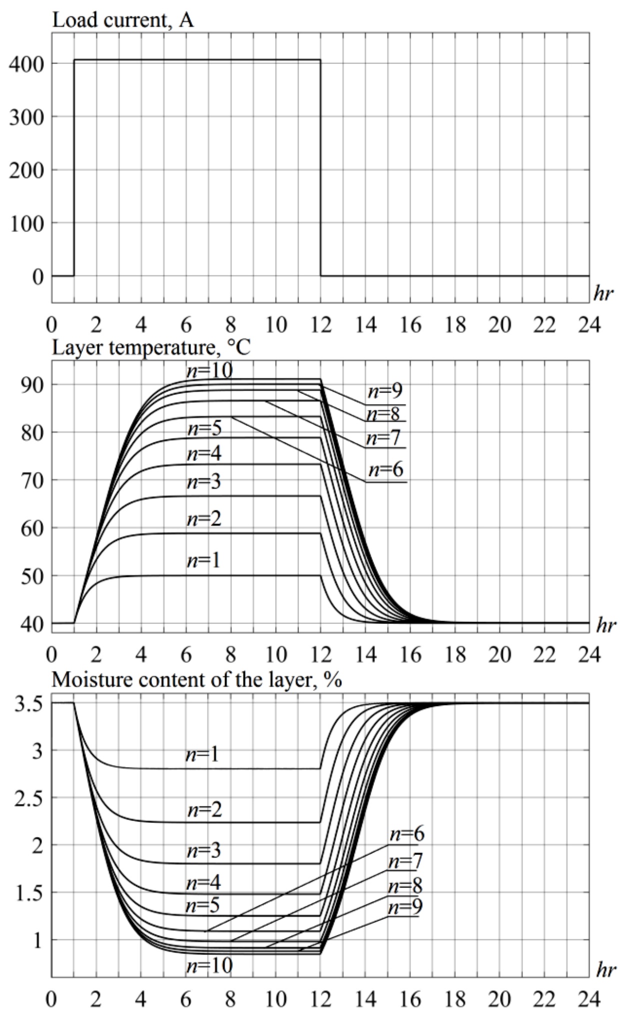

Fig. 3. Simulation results

The moisture content of cellulose insulation was calculated for the following initial data: A_w = 6.1; B_w = 0.04; k_w = 0.33; a_w = 0.0033 (empirical coefficients correspond to K-120 cable paper [24]). The mass of cellulose insulation of the transformer is assumed to be 6 tons, the mass of transformer oil is 47 tons. The graphs of changes in the parameters of these processes obtained as a result of modeling are shown in Fig. 3.

The steady-state values of temperatures, humidity, rates of relative aging of cellulose insulation and the aging itself in the layers of the model are given in Table 1.

Table 1

Results of modeling by layers

Layer	$\theta(n)$, °C	$W(n)$, %	V_θ	V_W	$V_\theta \cdot V_W$
10	91,10	0,846	0,4403	2,2545	0,9927
9	89,90	0,877	0,4111	2,3912	0,9830
8	88,86	0,913	0,3485	2,5588	0,8917
7	86,55	0,980	0,2666	2,8323	0,7551
6	83,23	1,089	0,1830	3,2981	0,6036
5	78,80	1,250	0,1120	4,0648	0,4553
4	73,27	1,480	0,0609	5,2739	0,3212
3	66,61	1,800	0,0292	7,1129	0,2077
2	58,82	2,237	0,0123	9,8245	0,1208
1	49,97	2,800	0,0045	13,7142	0,0617

From the results obtained it follows:

- under these conditions, the most consumable resource and the most heated is the upper layer of the transformer winding;
- the increase in temperature and humidity from layer to layer is not a constant value. That is, the functions $\theta(n)$ and $W(n)$ are non-linear.

The following notation is used: $\theta_{\max} = \theta(N)$; $\theta_{\min} = \theta(1)$; $\Delta\theta = (\theta_{\max} - \theta_{\min})$; $W_{\max} = W(1)$; $W_{\min} = W(10)$; $\Delta W = W_{\max} - W_{\min}$.

Using the simulation results, the coefficients of temperature change relative to the maximum values and humidity relative to the minimum values in the winding are calculated:

$$k_\theta(n) = \frac{\theta_{\max} - \theta(n)}{\Delta\theta}; \quad k_W(n) = \frac{W(n) - W_{\min}}{\Delta W}.$$

The obtained dependencies $k_\theta(n)$ and $k_W(n)$ are approximated by polynomials of the third degree. These polynomial functions and the resulting quality of approximation are shown in Fig. 4. Approximation quality was assessed using the determination coefficient R^2. The calculated values of R^2 are close to 1, which indicates a sufficient quality of the approximation.

Using the obtained dependences of the coefficients $k_\theta(n)$ and $k_W(n)$, the dependences of the temperature $\theta(n)$ and humidity $W(n)$ of the layer as a function of θ_{max}, $\Delta\theta$, W_{min}, ΔW and n are obtained:

$$\theta(n) = \theta_{\max} - \Delta\theta \cdot k_\theta(n); \tag{8}$$

$$W(n) = W_{\min} + \Delta W \cdot k_W(n). \tag{9}$$

When assessing the rate of relative aging of the insulation, the hot-spot temperature of each layer was used, which is determined by the expression:

$$\theta_h(n) = \theta(n) + \Delta\theta_h, \tag{10}$$

where $\Delta\theta_h$ is the temperature rise of the winding above the oil temperature in this (n-th) layer, which, in accordance with the recommendations of IEC [4], is assumed to be 22 °C for all layers.

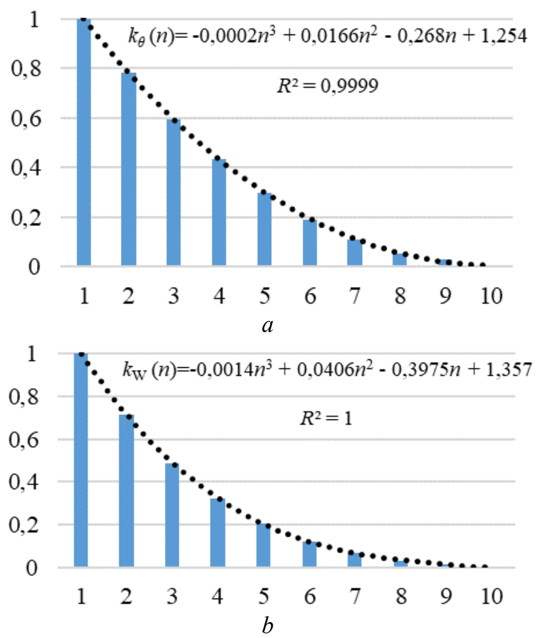

Fig. 4. Graphs of dependencies: a – $k_\theta(n)$; b – $k_W(n)$

The values of $W(n)$ and $\theta_h(n)$ from expressions (9) and (10) are substituted into the expressions for determining the rates of relative insulation aging. As a result of the action of temperature [6, 7]:

$$V_\theta(n) = 2^{\frac{(\theta_h(n)-98)}{6}} \tag{11}$$

and humidity

$$V_W(n) = \left(\frac{W(n)}{W_{BASE}}\right)^{1,493}. \tag{12}$$

where W_{BASE} is the base humidity of cellulose insulation, %.

The designation for the product of the relative rates of thermal and moisture aging of insulation for layers n and N has been introduced:

$$V_n = V_\theta(n) \cdot V_W(n); \tag{13}$$

$$V_N = V_\theta(N) \cdot V_W(N). \tag{14}$$

Evaluation of the effectiveness of the proposed method is based on the assumption that there is some non-top (n-th) layer with a higher insulation aging rate than in the top layer (N-th). Without taking this fact into account, we underestimate the intensity of insulation aging. Thus, the conditions under which the resource is underestimated are determined from the expressions:

$$V_N < V_n \tag{15}$$

or

$$V_N - V_n < 0. \tag{16}$$

In this case, it is assumed that V_N and V_n are positive and different from zero and infinity. The following index is proposed:

$$F = \frac{V_N}{V_n}. \tag{17}$$

Then condition (15) can be rewritten in the form:

$$F < 1 \tag{18}$$

Moreover, the greatest underestimation of the aging intensity is achieved with a minimum index F. Substituting expressions (11-14) into expression (17), we obtain an expression for determining F:

$$F = \frac{V_N}{V_n} = \frac{V_\theta(N) \cdot V_W(N)}{V_\theta(n) \cdot V_W(n)} = \frac{V_\theta(N)}{V_\theta(n)} \cdot \frac{V_W(N)}{V_W(n)}, \tag{19}$$

where

$$\frac{V_\theta(N)}{V_\theta(n)} = \frac{2^{\frac{(\theta_N-98)}{6}}}{2^{\frac{(\theta_n-98)}{6}}} = 2^{\frac{(\theta_N-\theta_n)}{6}}; \tag{20}$$

$$\frac{V_W(N)}{V_W(n)} = \frac{\left(\frac{W(N)}{W_{BASE}}\right)^{1,493}}{\left(\frac{W(n)}{W_{BASE}}\right)^{1,493}} = \left(\frac{W(N)}{W(n)}\right)^{1,493}. \tag{21}$$

Substituting (20, 21) into (19), taking into account (8), (9) and approximation results in Fig. 4, we obtain:

$$\frac{V_\theta(N)}{V_\theta(n)} = 2^{\frac{(\Delta\theta(-0,0002n^3 + 0,0166n^2 - 0,268n + 1,254)}{6}}; \tag{22}$$

$$\frac{V_W(N)}{V_W(n)} = \left(\frac{1}{1 + \frac{\Delta W}{W_{\min}}(-0,0014n^3 + 0,0406n^2 - 0,3975n + 1,357)}\right)^{1,493} \tag{23}$$

Analysis of expressions (15) and (16) shows that:

$$\frac{V_\theta(N)}{V_\theta(n)} \le 1 \quad \text{and} \quad \frac{V_W(N)}{V_W(n)} \ge 1.$$

Therefore, the F index can be either less or greater than 1. When F>1, the greatest insulation aging occurs in the upper layer of the winding.

To determine the conditions under which $F_{\min}$ is achieved, the method of genetic algorithms [23] was applied. In accordance with this method, expression (19), taking into account expressions (22) and (23), is a fitness function, the minimum of which is to be determined.

The search for $F_{\min}$ was carried out using the *ga* function from the MATLAB software package. The initial restrictions on the input variables, the obtained value $F_{\min}$ of the value of the input parameters and the number of the layer at which $F_{\min}$ is reached are given in Table 2. This is a method of finding a function extremum by directional iteration of the values of the function arguments. Its advantage is that it does not impose requirements on the complexity of the function.

Table 2

The results of determining the indicator $F_{\min}$

Name, designation, unit measurements, variable type	Value range	Value for $F_{\min}$	$F_{\min}$ value	Layer number
Number of layers, N, pieces, integer	N=10	10	0,6182	8
Oil temperature range, $\Delta\theta$, °C, real	20<$\Delta\theta$<60	20		
Absolute humidity of the upper layer, $W(N)$, %, real	0,3<$W(N)$<1	0,3		
Winding humidity change range, ΔW, %, real	0<ΔW<1,5	1,5		

As can be seen from Table 2, the value of the index $F_{\min}$ = 0,6182 obtained during the operation of the genetic algorithm takes place for the eighth layer. From here, according to expression (17):

$$V_n = V_N / F_{\min} = 1{,}6176\ V_N . \quad (24)$$

Thus, the adjusted value of the insulation aging rate is 61.76 % higher than that calculated by the original method. If we assume that the wear rates V_n, V_N have a constant value, then the service life of the insulation will be reduced at these rates for different times. Wherein

$$V_n t_1 = V_N t_2 . \quad (25)$$

where t_1, t_2 are expected service life of cellulose insulation of the n-th and upper (N-th) layers of the winding, respectively, years.

Since for $F_{\min} < 1$ we have $V_n > V_N$, then $t_1 < t_2$. Then, taking into account (24) and (25), we have a reduction in the service life:

$$\Delta t = (t_2 - t_1) = t_2 (1 - F_{\min}) . \quad (26)$$

Where does the relative reduction in service life, expressed as a percentage, be defined as:

$$\Delta t / t_2 [\%] = (\Delta t / t_2) \cdot 100\% = (1 - F_{\min}) \cdot 100\%. \quad (27)$$

For example, with t_2 = 10 years and $F_{\min}$ = 0,6182 we get Δt = 3,918 years, t_1 = 6.182 years, $\Delta t/t_2$ [%] = = 39,18 %. That is, the calculation of the resource consumption time rate according to the proposed method gives a significantly lower (in the example by 39,18 %) residual insulation life.

Conclusions.

1. It has been established that the distribution in the layers of the winding of the average values of temperature and humidity of cellulose insulation in the direction of the vertical axis of the winding is multidirectional. Therefore, under certain conditions in which the insulation operates (for example, at high absolute humidity, a large temperature difference along the vertical axis of the winding, etc.), it is possible that the aging rate of the insulation under the action of temperature and moisture in the intermediate horizontal layer of the winding exceeds the aging rate in the layer with the most hot point, and as a result, greater wear of the intermediate layer.
2. The index F is proposed for assessing the excess rate of aging of cellulose insulation under the influence of temperature and moisture.
3. Using the method of genetic algorithms, the maximum excess of the rate of relative wear of insulation in the intermediate layer $F_{\min}$ was estimated under given restrictions on the parameters of temperature and moisture distribution, as well as the number of layers into which the transformer winding is mentally divided.
4. The method for determining the dynamics of the distribution of temperature and humidity along the vertical axis of the winding has been improved with experimentally obtained results of measurements of the ambient temperature, load current and calculated values of the thermophysical parameters of cellulose insulation, which makes it possible to improve the accuracy of assessing its technical condition.
5. The expressions obtained in the work for determining the index F refer to one variant of estimates of the average rate of relative wear of insulation from among those presented in the known literature. Namely, ratings:

- for thermally unimproved cellulose insulation;
- with the determination of the thermal wear rate according to the Montsinger equation;
- taking into account the relationship of various factors (temperature, humidity, and others) in the form of a product of aging rates as a result of the action of one factor.

5. In the future, it is planned to obtain an analytical expression for determining the index F for other assessment options: aging of paper insulation with improved thermal characteristics; determining the average rate of aging as a function of the activation energy E and the pre-exponential factor A; an additive form of the relationship of average aging rates, taking into account individual factors.

Conflict of interest. The authors declare no conflict of interest.

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M.O. Poliakov[1], *Doctor of Technical Science, Professor,*
V.V. Vasylevskyi[1], *PhD,*
[1] Zaporizhzhia Polytechnic National University,
64, Zhukovsky Str., Zaporizhzhia, Ukraine, 69063,
e-mail: polyakov@zntu.edu.ua;
lisses@ukr.net (Corresponding author)

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