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Dynamic thermal modeling and overload testing for optimization of transformer loadability in the context of energy transition

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SUMMARY

The energy transition will affect transformer load profiles due to use of tools to minimize peak loading and the increased contribution of distributed and intermittent energy resources. Understanding the thermal behavior of power transformers is, accordingly, a key element in optimizing system planning and operation to provide customers with a reliable power supply.

This paper summarizes Hydro-Québec's experience with extended temperature-rise tests performed on more than 50 units from three manufacturers. The paper reports on the statistics of oil and winding exponents extracted from these tests, and the results are compared with IEC- and IEEE- recommended parameters.

A parametric study to demonstrate the influence of model parameters on long-term and short-term emergency loading limits is described. The study confirms that winding and oil exponents, as well as the proportionality of oil and winding gradients, are the main parameters affecting dynamic loadability.

Finally, a study was performed on field measurement results for optimization of the IEC 60076-7 model parameters using curve-fitting tools to find the minimum of the least squares error. This data mining approach is useful since many transformers today operate without overload test data.

KEYWORDS

Transformer, Thermal model, Loading guide, Loadability

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1. INTRODUCTION

The energy transition will increase the thermal stress on the aging electrical infrastructure system due to increased loading and modified load profiles. The reliability and availability of assets on the network will continue to be a challenge with fewer opportunities to perform maintenance without impacting the stability of the electrical system. This new context leads the planning and operation engineers to optimize their tools to maximize the use of existing assets.

Transformers are the most strategic and expensive assets in substations, and they define substation power transit capacity. The power transit capacity is studied for normal cyclic loading, as well as for long-term and short-term emergency scenarios in the case of one or many outages of system elements. To perform these studies, transformer thermal models from international loading guides are generally used. The IEEE and IEC organizations have published loading guides [1], [2] with different theoretical background that can lead to different outputs. Even for a specific model, the parameterization will have a significant impact on the possible loads that can be applied to a transformer before reaching the maximum allowable internal temperatures. An increase of power capacity could require the addition of a power transformer in an existing substation, or the implementation of an entire new substation, which can be very expensive measures. It is then very important to be able to predict the transformer internal temperature in various loading scenarios to take the best decisions regarding significant investment in the electrical infrastructure.

This paper studies the transformer thermal models provided in loading guides to better understand the impact of parameterization on the outputs of the models for short-term and long-term emergency loading. Extended temperature-rise tests at various loads (below and beyond nameplate ratings) are used to validate the overloading capacity of many transformers and to calculate parameters that can be used to predict the temperature for any load profiles. Then, a parametric study quantifies how a change in some of the main parameters affects the short-term and long-term emergency loading capacity. Finally, the paper presents an example of parameterization from the monitoring data of a transformer in service. The parameters extracted from these tests are compared with the recommended values in the standards.

2. TRANSFORMER LOADING GUIDE EQUATIONS

Direct measurement of winding hottest spot temperature (hot-spot) using fiber-optic probes has been increasingly used since the mid-1980s as reported in many papers. By analyzing measured results from tested power transformers, it has been reported that hot-spot temperature rises over top-oil temperature following a step-load change is a function dependent on time as well as transformer load (overshoot time-dependent function). This phenomenon is caused by the fact the oil-cooling medium has mechanical inertia in addition to thermal inertia. The effect is greatest for natural cooling (ON, less for pumped-oil cooling OF), and negligible for directed-flow pumped-oil cooling (OD). This overshoot has been modeled and a mathematical representation was introduced in the IEC 60076-7 loading guide [1]. Figure 1 illustrates the overshoot for real transformers with natural (ON) and forced (OF) cooling in comparison with the standard IEC 60076-7 model. This overshoot does not mean that the absolute hot-spot temperature will exceed the steady state value following a step-load change; however, this phenomenon accelerates the hot-spot temperature increase so it has a significant effect on the short-term emergency loading that can be applied, see Figure 2. This same overshoot can also be observed while using the IEEE Annex G model, but not with the IEEE Clause 7 model (Figure 2) [2]. Annex G uses physics-based modeling, including oil viscosity effect and the variation of DC, eddy and stray losses with temperature [3], and the IEC 60076-7 uses a simplified mathematical representation based on observed data [4], [5].

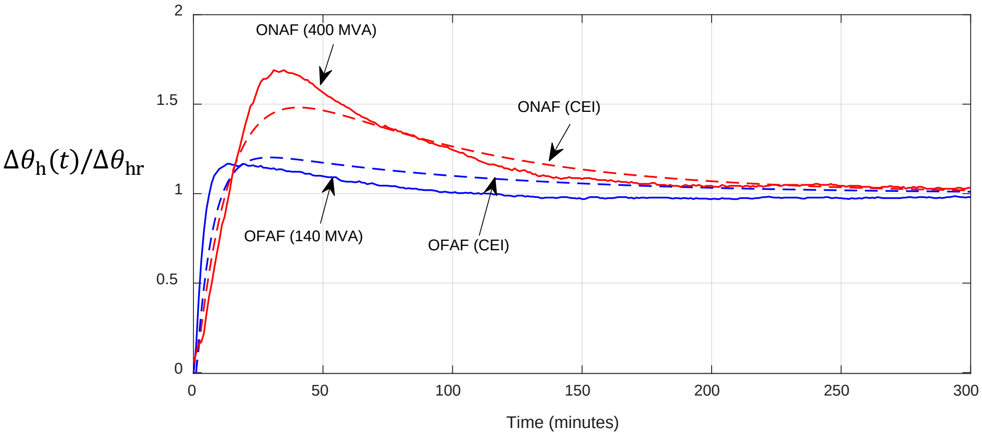
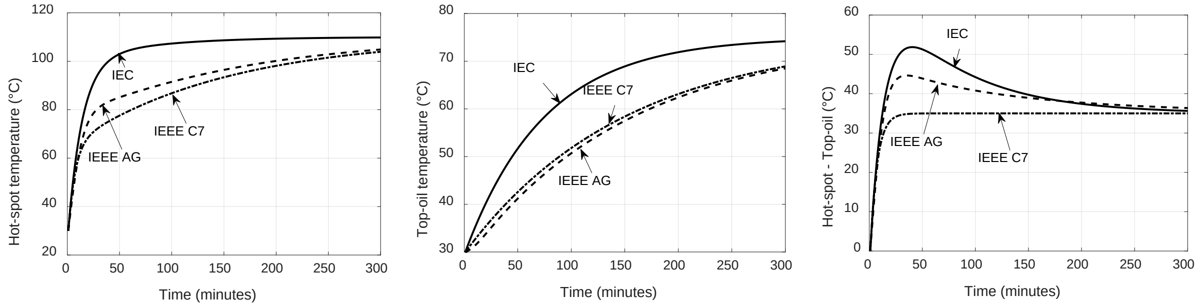


Figure 1: Thermal overshoot extracted from temperature rise tests and numerical representation from IEC 60076-7



(a) (b) (c)

Figure 2: Comparison of dynamic (a) hot-spot, (b) top-oil and (c) thermal overshoot for IEC 60076-7, IEEE Annex G and IEEE Clause 7 models for a step-load increase from 0 to 1 pu

The symbols used in this paper are the same as in the IEC 60076-7 standard [1]. The differential equation for top-oil temperature in the IEC 60076-7 loading guide (inputs load K, ambient temperature θ_{a}, output oil temperature θ_{o}, with constants oil exponent x, load to no-load losses ratio R, oil time constant τ_{o}) is

$$\Delta\theta_{\text{or}}\left[\frac{K^2R+1}{R+1}\right]^x = k_{11}\tau_{\text{o}}\times\frac{d\theta_{\text{o}}}{dt}+\Delta\theta_{\text{o}} \tag{1}$$

The differential equation for hot-spot temperature rise (input K, output hot-spot gradient $\Delta\theta_{\text{h}}$,) is solved as the sum of two differential equation solutions, where

$$\Delta\theta_{\text{h}} = \Delta\theta_{\text{h1}} - \Delta\theta_{\text{h2}} \tag{2}$$

The two equations are

$$k_{21}\times K^y\times\Delta\theta_{\text{hr}} = k_{22}\times\tau_{\text{w}}\times\frac{d\Delta\theta_{\text{h1}}}{dt}+\Delta\theta_{\text{h1}} \tag{3}$$

and

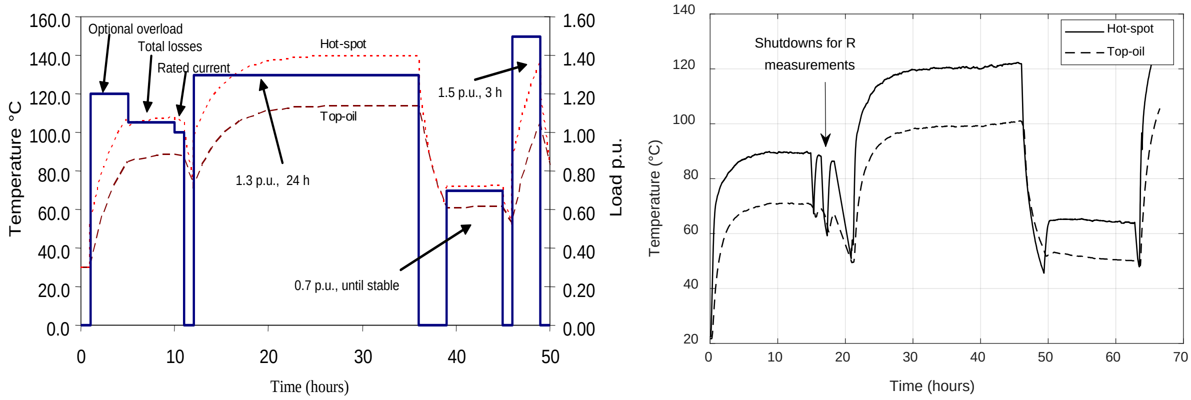
$$(k_{21}-1)\times K^y\times\Delta\theta_{\text{hr}} = \left(\frac{\tau_0}{k_{22}}\right)\times\frac{d\Delta\theta_{\text{h2}}}{dt}+\Delta\theta_{\text{h2}} \tag{4}$$

The final equation for the hot-spot temperature is

$$\theta_{\text{h}} = \theta_{\text{a}}+\Delta\theta_{\text{o}}+\Delta\theta_{\text{h}} \tag{5}$$

3. EXTENDED TEMPERATURE-RISE TESTS

Since 1988, Hydro-Québec has specified an extended temperature-rise test, as shown in Figure 3 [6], [7]. This test consists of applying, after the temperature-rise test at rated current, an overload of 130% of rated current for 24 hours, followed by a cool down period of 3 hours (used to calculate the oil time constant), then applying 70% of rated current until temperature stability and finally applying 150% of rated current for 3 hours or until the hot-spot temperature reaches 140 °C. At the end of each load level, the DC resistance of the windings is measured to determine the average temperature.



(a) (b)

Figure 3: (a) Extended temperature-rise test load profile and (b) example of a real test on a 400-MVA, 230/120/12.5-kV autotransformer

Overload temperature-rise testing demonstrates that a transformer has the specified overload capacity if the following pass criteria are met:

- The temperature of winding hot-spots or metal parts in contact with insulation does not exceed 140 °C.
- The temperature of metal parts not in contact with cellulosic insulation does not exceed 180 °C.
- Simulation of winter and summer load profiles using thermal characteristics (top-oil temperature and hot-spot gradients, oil and winding exponents) extracted from overload testing demonstrates that the transformer can withstand summer and winter daily overload profiles without exceeding the maximum permissible temperature.
- Oil in the conservator does not overflow.
- Dissolved gas-in-oil values remain below specified limits.

Since 1991, more than 60 transformers have been tested and less than 10% of them failed the test. Reported causes of failure detected by DGA are mainly overheating in OLTC leads due to connection errors, overheating due to saturation of magnetic shunts and overheating due to excessive current in the core.

These pass criteria are easy to verify, except winding hot-spot temperatures, which can be estimated using direct measurements or calculations based on transformer design. Since 2010, fiber-optic probes are specified for direct measurement of winding hot-spot temperatures.

For the simulation of winter and summer load profiles, a loading guide model is used with the parameters extracted from the extended temperature-rise tests. The data required for the parameterization of the loading guide model is the following (at the stability of 70%, 100% and 130% load steps).

- Winding gradient (g): average winding temperature minus average oil temperature using an extrapolation of the hot winding resistance measurement at the time of shut-down; g can also be estimated using an extrapolation of the hot winding resistance measurement curve to the ultimate cool down value that is a good estimation of the average oil temperature in the winding

- Hot-spot gradient ($\Delta\theta_{\mathrm{h}}$): the difference between hot-spot and top-oil temperature
- Top-oil temperature rise over ambient ($\Delta\theta_{\mathrm{o}}$)
- Losses injected in the transformer

4. PARAMETRIC STUDY OF THE IEC 60076-7 EQUATIONS

A parametric study was carried out to better understand the effect of parameters on the possible overload capacities of transformers during short-term and long-term emergencies. For short-term emergency study, the ambient temperature is varied from -30 °C to 40 °C with 10 °C interval (8 values), and for each ambient temperature the loading prior to the event is calculated to obtain a hot-spot temperature of 110 °C. Then, a simulation is performed to determine the maximum loading that can be applied on the transformer until the hot-spot reaches 140 °C after 30 minutes. For long-term emergency loading, the maximum loading is calculated as if the transformer were operated in steady state at a maximum temperature of 140 °C.

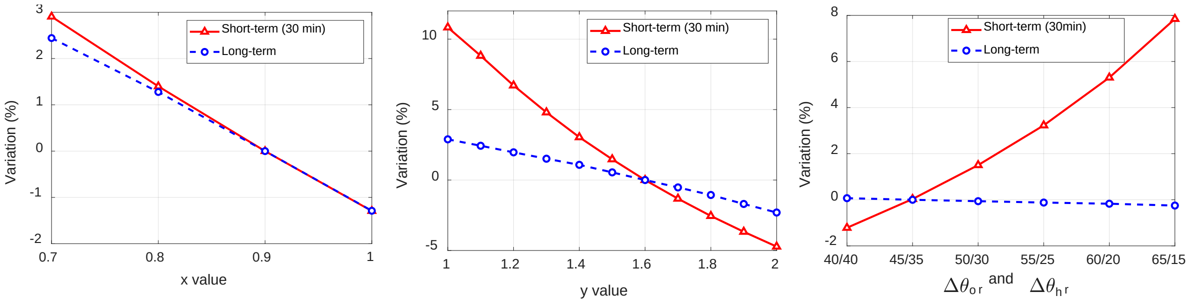
A reference ONAF transformer is created using the following parameters: rated top-oil rise over ambient $\Delta\theta_{\mathrm{or}} = 45$ °C; rated hot-spot to top-oil gradient $\Delta\theta_{\mathrm{hr}} = 35$ °C; losses ratio $R = 8$; oil exponent $x = 0.9$; winding exponent $y = 1.6$; $k_{11} = 0.5$; $k_{21} = 2.0$; $k_{22} = 2.0$; oil time constant $\tau_{\mathrm{o}} = 150$ min and winding time constant $\tau_{\mathrm{w}} = 7$ min. Then the parameters $\Delta\theta_{\mathrm{or}}$, $\Delta\theta_{\mathrm{hr}}$, R, x, y, τ_{o} and τ_{w} are individually modified over a range of values and the new applicable loads are calculated for the eight ambient temperatures. Averages of the percent differences between the modified transformer and the reference transformer are calculated and are reported in Table 1. The reference transformer is built with a combination of parameters recommended in the IEC and IEEE loading guides. For example, the *x* and *y* exponents correspond to the oil and winding exponents from IEEE C57.91-2011 and most of the other parameters are from Table 4 of the IEC 60076-7 standard.

Table 1: Variation of transformer loadability vs. reference transformer

Parameter	Range	Short-term emergency loading vs. reference transformer	Long-term emergency loading vs. reference transformer
y	1.0 to 2.0	+10.83% to -4.72%	+2.89% to -2.31%
x	0.7 to 1.0	+2.91% to -1.29%	+2.44% to -1.29%
$\Delta\theta_{\mathrm{or}}$ / $\Delta\theta_{\mathrm{wr}}$	40/40 to 65/15	-1.25% to +7.81%	+0.04% to -0.15%
τ_{w} (min)	5 to 9	-1.11% to + 1.34%	No effect
R	6 to 10	+0.34% to -0.20%	+0.31% to -0.19%
τ_{o} (min)	100 to 200	-0.36% to +0.23%	No effect

One somewhat surprising result is the influence of τ_{w} on short-term loadability since the observed data is after 30 minutes and τ_{w} in in the range of 5 to 9 minutes. This is explained by the mathematical representation of the thermal overshoot, using τ_{w} in (3), which has a peak value at about 40 minutes, thus having an effect at the 30 minutes observation time. The parameters having the most impact on transformer loadability are the oil and winding exponents and gradients. Figure 4 illustrates the parametric study results for these parameters. For instance, a change of the winding exponents from the IEEE (1.6) to the IEC (1.3) recommended value generates an additional loading capacity of 2.6% and 4.8% for short-term and long-term emergencies respectively.

The variability in oil and winding gradients for different transformers is shown in Figure 5, which illustrates the oil and winding gradients of about 1,000 ONAF transformers from Hydro-Québec's fleet. The values were adjusted to match the specified hot-spot temperature rise over ambient for all transformers, which is 80 °C. The statistics indicate the following: rated top-oil rise over ambient $\Delta\theta_{\mathrm{or}} = 53.9 \pm 8.5$ and rated hot-spot gradient $\Delta\theta_{\mathrm{hr}} = 26.1 \pm 8.5$ (based on 984 values). Figure 6 shows that the proportionality of gradients has a significant impact on the short-term loadability.



(a) (b) (c)

Figure 4: Parametric effect of (a) oil and (b) winding exponents and (c) gradients on the variation of short-term overloading capacity vs. reference transformer

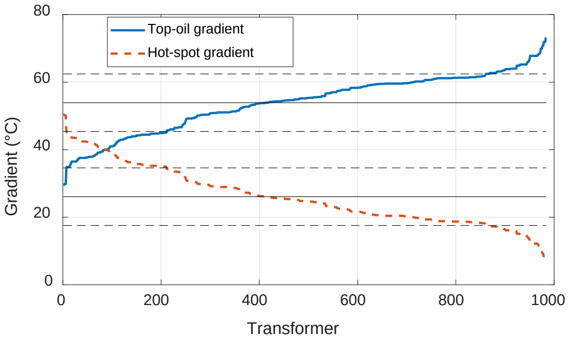


Figure 5: Oil and winding gradients for a population of ONAF transformers

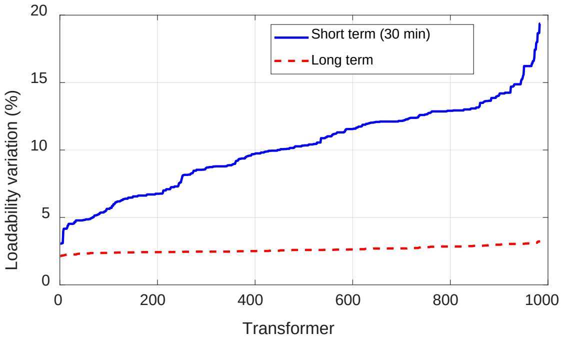


Figure 6: Increased loadability using real gradients and recommended IEC exponents

For long-term emergency loading, the calculations assume that the transformer is operating in steady state. This is a conservative approach because since the load profile is usually not uniform, the maximum loading is only applied for a small part of the time, and the thermal inertia of the transformer contributes to reducing the temperature observed at the daily peak load. The load profile depends on the season and the type of load (industrial or residential). In winter, there are typically two peaks in morning and evening for residential areas, and in summer, the load is more evenly distributed during the day. Figure 7 illustrates the winter load profile in per unit of the maximum load of the day. In Figure 8, a simulation of the reference transformer is made to calculate the maximum loading that can be applied on the winter load profile, at an ambient temperature of 0°C, until the maximum hot-spot temperature of 140 °C is reached. The resulting maximum loading (1.45 pu) is compared to the more conservative steady-state approach (1.41 pu). A margin of 6 °C at the daily peak load is observed and this corresponds to an additional load of 2.8% that can be applied without exceeding the transformer hot-spot temperature limit.

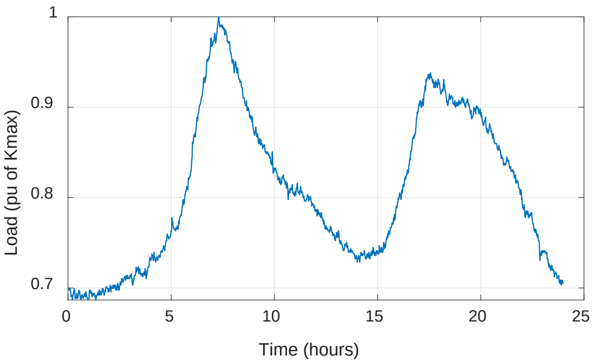


Figure 7: Example of winter load profile, in per unit of the maximum load of the day

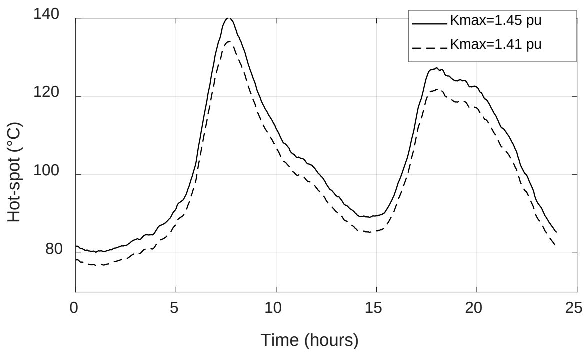


Figure 8: Increased loadability while considering load profile

5. OIL AND WINDING EXPONENTS ESTIMATION FROM EXTENDED TEMPERATURE-RISE TESTS

From (1), the steady-state oil temperature rise can be calculated using

$$\Delta\theta_{\mathrm{o}} = \Delta\theta_{\mathrm{or}}\left[\frac{K^2 R+1}{R+1}\right]^x = \Delta\theta_{\mathrm{or}}\left[\frac{K^2 P_{\mathrm{c}}+P_{\mathrm{o}}}{P_{\mathrm{c}}+P_{\mathrm{o}}}\right]^x \tag{6}$$

which corresponds to

$$\Delta\theta_{\mathrm{o}} = \Delta\theta_{\mathrm{or}}\left[\frac{Losses\ at\ load\ K}{Rated\ losses}\right]^x \tag{7}$$

In logarithmic form we get

$$\log(\Delta\theta_0) = x * \log\left(\frac{Losses\ at\ load\ K}{Rated\ losses}\right) + \log\left(\Delta\theta_{\mathrm{or}}\right) \tag{8}$$

With a linear regression, we can calculate x. It is more accurate to use the losses measured during the test than using (6). In (6), the losses are considered proportional to K^2 without incorporating the effect of temperature. For a test at constant current, the DC losses increase with temperature and the AC losses decrease with temperature, therefore it is more accurate to use the measured losses as in (7).

The steady-stage hot-spot and winding gradients, $\Delta\theta_{\mathrm{h}}$ and g respectively, can be calculated using

$$\Delta\theta_{\mathrm{h}} = \Delta\theta_{\mathrm{hr}} \times K^y \text{ and } g = g_{\mathrm{r}} \times K^y \tag{9}$$

Then using a logarithmic linear regression, the exponent y can be calculated. The exponent y extracted using both approaches is not identical.

The parameter g can be calculated as the difference between the average winding temperature, using the hot resistance extrapolated at shutdown, and the average oil temperature calculated as the top-oil temperature minus the average of top and bottom radiator temperatures. The estimation of the average oil temperature using this indirect approach can lead to error because the average temperature in the windings can be different, and then the average temperature of the oil in the tank can differ from the average temperature of the oil inside the windings. A better approach is to use a curve fitting of the resistance measurement to estimate the resistance at shutdown and the asymptotic resistance value. This asymptotic resistance value is a good estimation of the average oil temperature in the winding. The parameter g_{A} is the difference between the average temperature at shutdown and the asymptotic average temperature of the winding after its cool down, as shown in Figure 9.

Figure 10 illustrates the linear regression of the log values of winding gradients $\Delta\theta_{\mathrm{h}}$, g and g_{A}. It shows that the y is similar in all approaches but the regression using g_{A} is better, showing that the methodology provides a better accuracy. The figure also shows that $\Delta\theta_{\mathrm{h}}$ measured using fiber-optic probes is higher than g and g_{A}, which is the normal behavior. Finally, g_{A} is higher than g since the asymptotic temperature after cool-down is a bit lower than the average temperature in winding at the time of shutdown.

Figure 11 illustrates the oil and winding gradients extracted from 53 extended temperature-rise tests on ONAN/ONAF/OFAF transformers from three manufacturers, ranging from 47 MVA to 550 MVA, and 120 kV to 735 kV. The values from a previous study on this topic [8] are also included in the graphs.

The statistics indicate the following:

- Top-oil exponent $x = 0.75 \pm 0.05$ (based on 53 values)
- Winding exponent $y = 1.20 \pm 0.29$ (based on 89 values)

This analysis confirms that the oil and winding exponents provided in the IEEE loading guide (0.9 and 1.6) are conservative and the ones proposed in the IEC loading guide (0.8 and 1.3) more accurately represent the average behavior of the tested transformers.

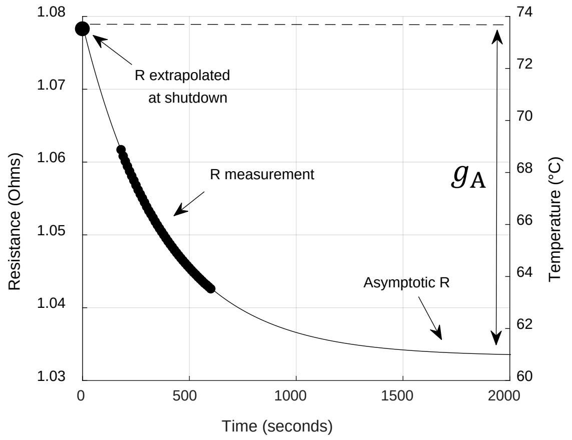


Figure 9: Calculation of g_{A} using the cool down resistance measurement after shutdown

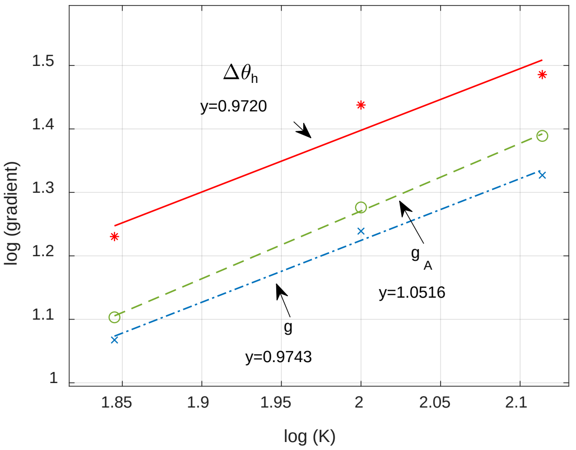
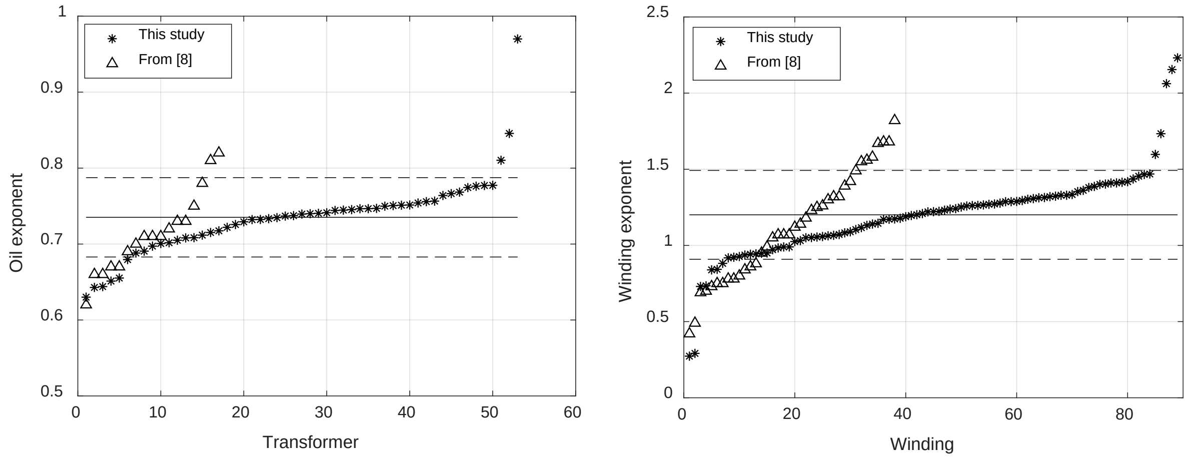


Figure 10: Log-log graph showing different estimations of y using $\Delta\theta_{\mathrm{h}}$, g and g_{A}



(a) (b)

Figure 11: Exponents extracted from extended temperature rise tests (a) oil x (b) winding exponent y

6. PARAMETERS ESTIMATION FROM FIELD MEASUREMENTS

Extended temperature-rise tests were not performed for most transformers presently installed, so parameterization from these tests is not possible. An alternative approach is to use on-line temperature measurements of top-oil temperature, ambient temperature, and the load to estimate $\Delta\theta_{\mathrm{or}}$, x and τ_{o}. This approach is valid as long as the cooling stage and tap position remain approximately constant for a sufficient period of time [9]. Such a dataset comprising 55 days of measurements on a transformer rated 66 MVA, 225/26.4 kV with loads varying from 0.50 to 1.15 pu was used for an on-line parameterization study. For the analysis, the dataset was separated into 13 sets of independent 4-day periods. The parameters optimization was performed using MATLAB® *MultiStart* and *lsqcurvefit* tools to minimize the least squares error between measured and simulated top-oil temperature. Figure 12 illustrates an example of data fitting for a 4-day period with the following optimized parameters: $\Delta\theta_{\mathrm{or}} = 47.3$ °C, $x = 0.62$ and $\tau_{\mathrm{o}} = 165$ min. The estimated rated top-oil rise over ambient is close to the 51.2 °C value obtained from the temperature-rise test. The only parameter that showed a clear correlation with temperature is $\Delta\theta_{\mathrm{or}}$, illustrated in Figure 13. This is in line with the results shown in previous studies [10]. Further studies would be required to assess the impact of this behavior on long-term and short-term emergency loading limits.

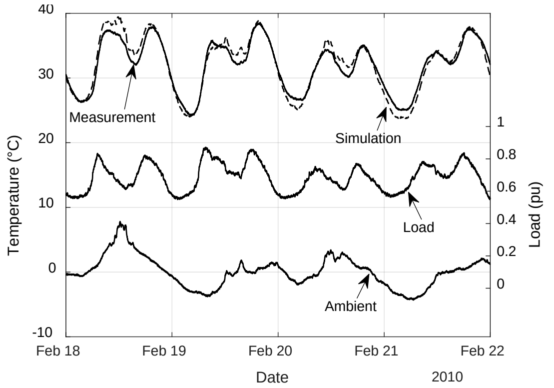


Figure 12: Comparison between field measurements and simulations

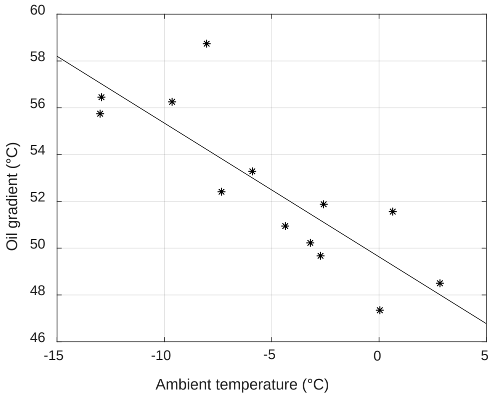


Figure 13: $\Delta\theta_{\mathrm{or}}$ values extracted from field measurements at various ambient temperature

7. CONCLUSION

The energy transition will affect the load profiles, and the use of effective thermal models for strategic assets like transformers is essential to successfully plan and operate the network of the future. This contribution reviews existing loading guides and shows that there are significant variations between the IEEE and IEC model outputs regarding short-term and long-term emergency conditions. The presented parametric study quantifies the impact of the most important parameters in the loadability predictions. These parameters, namely the oil and winding gradients and exponents, were extracted from many extended temperature-rise tests. The conclusion is that the IEEE-recommended exponents are conservative, and the IEC exponents more accurately represent the behavior of transformers tested in the last three decades. The on-line parameterization study showed a correlation between the oil gradient and the temperature, which brings another level of complexity to be tackled for the assessment of short-term and long-term emergency limits.

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