PC57.91™/D8 Draft Guide for Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

Developed by the

Transformers (PE/TR)
of the
IEEE Power and Energy Society

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IEEE SA Standards Board

Abstract: The contents of this guide describe the assumptions, techniques, and methods for estimating the effects of loading above nameplate of mineral-oil-immersed distribution and power transformers as well as step voltage regulators. Consequences due to loading above nameplate ratings are discussed including damage to insulation, production of gases in oil, and ultimately loss of life effects. In addition, effects of loading on auxiliary equipment are presented. Different types of loading scenarios as well as variations in ambient temperature and altitude are described. Effects due to different cooling techniques and their impacts on transformer capacity are reviewed. Transformer temperature criteria are also provided. Finally, calculation methods with and without consideration to duct oil effects are provided and with sample temperature calculations.

Keywords: distribution transformer, step-voltage regulators, IEEE C57.91, loss-of-life, short-term overloads, long-term overloads, loading, mineral-oil-immersed, insulation aging, power transformer

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Introduction

This introduction is not part of PC57.91/D8, Draft Guide for Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators.

This guide is applicable to loading 65 °C mineral-oil-immersed distribution and power transformers. Other guides for loading, IEEE Std C57.91-1981 (prior edition), IEEE Std C57.92™-1981,[1] and IEEE Std C57.115-1991 (re-designated as IEEE Std 756) are all combined in this document. The reason for this is the basic theory of transformer loading is the same, whether the subject is distribution transformers or small, medium, or large power transformers. Recognizing that there are different types of construction, special considerations, and the degree of conservatism involved in the loading of this equipment, specific sections are devoted to just power transformers and just distribution transformers. In the previously referenced information, the guide for units larger than 100 MVA referenced the IEEE Std C57.92-1981 loading guide for units up to and including 100 MVA.

The update to the work performed in 1995 expands the scope to include step-voltage regulators and replaces Annex A with an improved discussion on bubble evolution. Subclause 8.4 was added for step-voltage regulators. In addition, the formula notations were changed to reflect the updated IEEE style and several typographical errors were fixed. Both Clause 7 and Annex G calculation procedures remain in place. Clause J was removed as it was accessed as out-of-date information and is expected to be re-introduced in the future in a new standard on transformer monitoring systems. Annex C and Annex G were changed from normative to informative.

As IEEE Std C57.12.00-2010[2] has adopted an insulation life of 180 000 hours at 110 °C, Table 2 of this guide was moved to Annex I for historical reference.

In previous guides, different insulation aging curves were used for power transformers and distribution transformers. This was caused by the different evaluation procedures used. The distribution transformer curve was based on aging tests of actual transformers. The power transformer curve was based on aging insulation samples in test containers to achieve 50% retention of tensile strength. Investigation of cellulosic insulating materials removed from transformers that had long service life has led knowledgeable people to question the validity of the 50% criteria. One newer criterion that has been suggested is 25% tensile retention. This guide allows the user to select the criteria most acceptable to their need, based on percent strength retention, polymerization index, etc. An insulation aging factor may thus be applied.

A per unit life concept and aging acceleration factor are provided in this loading guide. The equations given may be used to calculate percent loss of total insulation life, as has been the practice in earlier editions of the transformer loading guides. The relationship between insulation life and transformer life is a question that remains to be resolved. It is recognized that under the proper conditions, transformer life can well exceed the life of the insulation.

The assumed characteristics used in previous guides contained tables of loading capability based on assumed typical transformer characteristics. These assumed characteristics were recognized as not being those of manufactured units, which may have a wide range of characteristics. In this guide, these tables were removed since computer technology permits calculation of loading capability based on specific transformer characteristics.

Two methods of calculating temperatures were provided in prior editions of this guide. Clause 7 contained temperature equations that use the winding hottest spot rise over tank top oil and assume that the oil temperature in the cooling ducts is the same as the tank top oil during overloads. Recent research using imbedded thermocouples and fiber optic detectors indicates that the fluid flow occurring in the windings

[1] IEEE Std C57.92-1981 has been withdrawn; however, copies can be obtained from Global Engineering, 15 Inverness Way East, Englewood, CO 80112-5704, USA, tel. (303) 792-2181 (http://global.ihs.com/).

[2] Information of references can be found in Clause 2.

during transient heating and cooling is an extremely complicated phenomena to describe by simple equations. These recent investigations have shown that during overloads, the temperature of the oil in the winding cooling ducts rises rapidly and exceeds the top-oil temperature in the tank. An alternate set of equations based on this concept had been provided in Annex G. The change of losses with temperature and liquid viscosity effects, and variable ambient temperature was incorporated into the equations.

Prior changes in the guide included information to load transformers operating more accurately down to a −30 °C ambient, this information concerns loss of diversity due to cold load pick-up or unusually low ambient temperatures.

Transformers rated 55 °C rise were generally replaced as a standard offering by most manufacturers around 1966. Their replacements were originally rated 55/65 °C and, in 1977, the single 65 °C rated transformers became the industry standard offering. The higher temperature ratings are based on thermally upgraded oil-paper-enamel insulation systems. Loading of 55 °C insulation system transformers is covered in Annex D.

Changes in the Guide for 2023 includes a review of temperature limits of other metallic parts in C57.12.00-2015, C57.163-2015, and IEC 60076-7:201 and Table 9 in this Guide. The document abstract and keywords were updated. Clause 5 has been updated. The Annex G model was brought forward into the body in Clause 7 and previous Clause 7 material merged as a special case of the model. Clause 10 was added to expand the topic of transformer loading to developing transformer ratings. Appendix A has been updated. The contents of Appendix B.1.1 had become outdated with revision of C57.19.100 and have been brought current with this revision. Appendix K shows how the past Clause 7 was a special case for the past Annex G, now Clause 7 model. Annex J was added to provide historical perspectives. Rather than provide the outdated BASIC computer model, Open-Source code has been developed and tested with discussion provided in an updated Annex G. The definitions were updated to accommodate changes in Clause 7.

Suggestions for improvement gained in the use of this guide will be welcomed. They should be sent to the IEEE Standards Association.

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Draft Guide for Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

1. Overview

1.1 Scope

This guide provides recommendations for loading mineral-oil-immersed transformers and step-voltage regulators, with insulation systems rated for a 65 °C average winding temperature rise, at rated load. This guide applies to transformers manufactured in accordance with IEEE Std C57.12.00[1] and tested in accordance with IEEE Std C57.12.90, and step-voltage regulators manufactured and tested in accordance with IEEE Std C57.15. Since a substantial population of transformers and step-voltage regulators with insulation systems rated for a 55 °C average winding temperature rise at rated load are still in service, recommendations that are specific to this equipment are also included.

This standard incorporates open-source code hosted on the IEEE Open-Source Platform.

1.2 Purpose

This guide provides recommendations on loading and loading beyond nameplate of mineral-oil-immersed transformers and step-voltage regulators, considering prescribed current and temperature limits and their effect on insulation life. This guide is intended for use by equipment end-users in planning and operating transformers and voltage regulators, utilizing the equipment's loading capability to its maximum extent while understanding the impacts of utilizing this capability. This guide also provides a practical and theoretical basis for the development of transformer and step-voltage regulator thermal models and end-user continuous and emergency ratings.

1.3 Word Usage

The word *shall* indicates mandatory requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted (*shall* equals *is required to*).[2,3]

The word *should* indicates that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others; or that a certain course of action is preferred but not necessarily required (*should* equals *is recommended that*).

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[1] Information of references can be found in Clause 2.
[2] The use of the word *must* is deprecated and cannot be used when stating mandatory requirements; *must* is used only to describe unavoidable situations.
[3] The use of *will* is deprecated and cannot be used when stating mandatory requirements; *will* is only used in statements of fact.

The word *may* is used to indicate a course of action permissible within the limits of the standard (*may* equals *is permitted to*).

The word *can* is used for statements of possibility and capability, whether material, physical, or causal (*can* equals *is able to*).

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std C57.12.00™, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.[4, 5]

IEEE Std C57.12.90™, IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers.

IEEE Std C57.15™, IEEE Standard Requirements, Terminology, and Test Code for Step-Voltage Regulators.

IEEE Std C57.100™, IEEE Standard Test Procedure for Thermal Evaluation of Insulation Systems for Liquid-Immersed Distribution and Power Transformers

Draper, Zachary, Roizman, Oleg. "IEEE C57.91 Thermal Models". https://opensource.ieee.org/inslife/ieee-c57.91-thermal-models/-/archive/main/ieee-c57.91-thermal-models-main.zip (supplement to https://opensource.ieee.org/inslife/ieee-c57.91-thermal-models

3. Definitions, acronyms, and abbreviations

3.1 Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.[6]

aging acceleration factor: For a given hottest spot temperature, the rate at which transformer insulation aging is accelerated compared with the aging rate at a reference hottest spot temperature. The reference hottest spot temperature is 110 °C for 65 °C average winding rise and 95 °C for 55 °C average winding rise transformers (without thermally upgraded insulation). For hottest spot temperatures in excess of the reference hottest spot temperature, the aging acceleration factor is greater than 1. For hottest spot temperatures lower than the reference hottest spot temperature, the aging acceleration factor is less than 1.

ambient temperature: The temperature of the medium such as air or water into which the heat of the transformer is dissipated.

average winding temperature: The average temperature of a winding as determined from the resistance measured across the terminals of the winding.

average winding temperature rise: The arithmetic difference between the average winding temperature of a winding and the ambient temperature.

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[6] *IEEE Standards Dictionary Online subscription* is available at: http://www.ieee.org/portal/innovate/products/standard/standards_dictionary.html.

bottom-oil temperature: The temperature of the liquid in a liquid-immersed transformer as measured at an elevation just below the bottom of the coils or in the oil flowing from the liquid cooling equipment into the transformer.

bottom-oil temperature rise: The arithmetic difference between the bottom-oil temperature and the ambient temperature.

core loss: The power dissipated in a magnetic core subjected to a time-varying magnetizing force. Core loss includes hysteresis and eddy-current losses of the core.

directed flow (oil-immersed forced-oil-cooled transformers): The principal part of the pumped insulating fluid from heat exchangers or radiators is forced, or directed, to flow through specific paths in the winding.

eddy current loss: The power loss in conductors resulting from the flow of eddy currents in parallel windings or in parallel winding strands. There is no test method to determine individual winding eddy loss or to separate transformer stray loss from eddy loss. The total stray and eddy loss is determined by measuring the total load loss during the impedance test.

estimated life: The expected service life derived from either service experience, or the results of tests performed in accordance with appropriate evaluation procedures, or both, as established by the responsible organization or technical committee.

hotspot temperature: If not specifically defined, is the hottest-spot temperature of the winding.

hottest spot temperature: If not specifically defined, is the hottest-spot temperature of the winding.

hottest spot temperature rise: The arithmetic difference between the hottest spot temperature and the ambient temperature.

load loss: a) of two-winding transformers (for the principal tapping): an active power absorbed at rated frequency when rated current is flowing through the line terminal(s) of one of the windings, the terminals of the other winding being short-circuited, and any winding fitted with tapping being connected on its principal tapping. b) of multi-winding transformers, related to a certain pair of windings (for the principal tapping): an active power absorbed at rated frequency when a current flows through the line terminal(s) of one of the windings of the pair, corresponding to the smaller of the rated power values of both windings of that pair, the terminals of the other winding of the same pair being short-circuited, any winding of the pair fitted with tapping being connected on its principal tapping and the remaining winding(s) being open-circuited. The load loss can also be considered for tapping other than the principal tapping. The reference current of two-winding transformers is, for any tapping, equal to the tapping current. For multi-winding transformers, the reference current or reference power are related to a specified loading combination.

no-load loss: The active power absorbed when a given voltage at rated frequency is applied to the terminals of one of the windings, the other winding(s) being open-circuited. Normally the applied voltage is the rated voltage and the energized winding, if fitted with multiple taps, is connected on its nominal tap.

non-directed flow (oil-immersed forced-oil-cooled transformers): Indicates that the pumped oil from heat exchangers or radiators flows freely inside the tank and is not forced to flow through the windings.

overload: The operating a transformer above its nameplate maximum power rating.

percent loss of life: The equivalent aging in hours over time (usually 24 hrs) times one hundred divided by the total insulation life in hours at the reference hottest spot temperature.

relative aging rate: The rate at which the transformer insulation aging is reduced or accelerated compared with the aging rate at reference hotspot temperature.

remaining useful life (RUL): The length of time from the present time to the estimated time at which the system (transformer) is expected to no longer perform its intended function within desired specifications.

residual life: The remaining period of time during which a system, structure, or component is expected to perform its essential function under specified service conditions.

standard remaining useful life: The time length of 180,000 hours (20.5 years), previously known as “minimum estimated life.”

stray loss: The power loss that is due to the stray leakage flux, which introduces losses in the core, clamps, tank, and other structural parts. There is no test method to determine individual stray loss or to separate transformer stray loss from eddy loss. The total stray and eddy loss is determined by measuring the total load loss during the impedance test.

temperature rise: The difference between the temperature of the part under consideration and the temperature of the cooling medium at the intake of the cooling equipment for air-cooled or water-cooled transformers or reactors.

temperature rise test: Also known as a heat run test, a routine procedure for determination of temperature and temperature rise values during factory testing of a transformer by supplying a current equivalent to the rated current, specified by the manufacturer or loses equivalent to full transformer loss

thermal model: The mathematical description of temperature distribution within transformer insulation and current conducting systems

thermal modelling: The process of creating a thermal model

top-oil temperature: The temperature of the top layer of the insulating liquid in a transformer, representative of the temperature of the top liquid in the cooling flow stream.

top-oil temperature rise: The arithmetic difference between the top-oil temperature and the ambient temperature.

total losses: The sum of the no-load loss and the load loss. In multi-winding transformers, the total losses refer to a specified loading combination.

transformer insulation life: For a given temperature of the transformer insulation, the total time between the initial state for which the insulation is considered new and the final state for which dielectric stress, short circuit stress, or mechanical movement, which could occur in normal service, and could cause an electrical failure. Alternatively, the total time (in hours/days/years) between the initial state for which the transformer insulation is considered new and the final state for which the insulation has deteriorated to the level of the high probability of dielectric failure.

winding hottest-spot temperature: The maximum temperature of the surface of any winding conductor in contact with insulation or liquid.

3.2 Acronyms and abbreviations

— BIT The bubble inception temperature

— ONAN A cooling class for a transformer having its core and coils immersed in insulating liquid and having a self-cooled rating with cooling obtained by the natural circulation of air over the cooling surface

— ONAF A cooling class for a transformer having its core and coils immersed in insulating liquid and having a self-cooled rating with cooling obtained by the natural circulation of air over the cooling surface, and a forced-air-cooled rating with cooling obtained by the forced circulation of air over this same cooling surface. (ONAN/ONAF was previously termed OA/FA).

— ODAF A cooling class for a transformer having its core and coils immersed in insulating liquid and cooled by forced circulation of the insulating liquid utilizing directed flow. The insulating liquid is cooled by external insulating liquid-to-air heat-exchanger equipment utilizing forced circulation of air over its cooling surface. (ODAF was previously termed FOA).

— OFAF A cooling class for a transformer having its core and coils immersed in insulating liquid and cooled by forced circulation of the insulating liquid utilizing non-directed flow. The insulating liquid is cooled by external insulating liquid-to air heat-exchanger equipment utilizing forced circulation of air over its cooling surface. (OFAF was previously termed FOA).

4. Effect of loading beyond nameplate rating

4.1 General

Applications of loads more than nameplate rating involve some degree of risk. While aging and longtime mechanical deterioration of winding insulation has been the basis for the suggested loading of transformers for many years, it is recognized that there are additional factors that may involve greater risk for transformers of higher megavoltampere (MVA) and voltage ratings. The risk areas that should be considered when loading large transformers beyond nameplate rating are listed next. Further discussion regarding these risks is provided in Clause 9 or in the annexes, as noted.

a) Evolution of free gas from insulation of winding and lead conductors (insulated conductors) heated by load and eddy currents (circulating currents between or within insulated conductor strands) may jeopardize dielectric integrity. See Annex A for further discussion.

b) Evolution of free gas from insulation and insulating fluid adjacent to metallic structural parts linked by electromagnetic flux produced by winding or lead currents may also reduce dielectric strength.

c) Loss of life calculations may be made as described in Clause 5. If a percent loss of total life calculation is made based on an arbitrary definition of a “normal life” in hours, one should recognize that the calculated results may not be as conservative for transformers rated above 100 MVA as they are for smaller units since the calculation does not consider mechanical wear effects that may increase with MVA rating.

d) Operation at high temperature will cause reduced mechanical strength of both conductor and structural insulation. These effects are of major concern during periods of transient overcurrent (through-fault) when mechanical forces reach their highest levels.

e) Thermal expansion of conductors, insulation materials, or structural parts at high temperatures may result in permanent deformations that could contribute to mechanical or dielectric failures.

f) Pressure build-up in bushings for currents above rating could result in leaking gaskets, loss of oil, and ultimate dielectric failure. See Annex A for further discussion.

g) Increased resistance in the contacts of tap changers can result from a build-up of oil decomposition products in a very localized high temperature region at the contact point when the tap changer is loaded beyond its rating. In the extreme, this could result in a thermal runaway condition with contact arcing and violent gas evolution. See Annex A for further discussion.

h) Auxiliary equipment internal to the transformer, such as reactors and current transformers, may also be subject to some of the risk identified above. See Annex A for further discussion.

i) When the temperature of the top oil exceeds 105 °C (65 °C rise over 40 °C ambient according to IEEE Std C57.12.00), there is a possibility that oil expansion will be greater than the holding capacity of the tank and result in a pressure that causes the pressure relief device to operate and expel the oil. The loss of oil may also create problems with the oil preservation system or expose electrical parts upon cooling.

4.2 Voltage and frequency considerations

Voltage and frequency influences should be recognized when determining limitations for loading a transformer beyond its nameplate rating. This is true even though, in all probability, there may be little control of these parameters during a loading beyond nameplate rating event. IEEE Std C57.12.00 defines the capability of a transformer to operate above rated voltage and below rated frequency. The users of this guide should recognize that, during conditions of loading beyond nameplate, the voltage regulation through the transformer may increase significantly (depending on the transformer impedance) due to the increased megavoltampere loading and possibly decreasing power factor.

A conservative guideline to reduce excessive core heating due to increased excitation is to reduce the transformer output volts per hertz limit by 1% for every 1% increase in voltage regulation during the loading beyond nameplate event. For example, if the voltage regulation at rated conditions is 6% and increases to 9% at some load above nameplate, the output volts per hertz limit might be reduced from 105% to 102%.

4.3 Supplemental cooling of existing self-cooled transformers

The load that can be carried on self-cooled transformers can usually be increased by adding auxiliary cooling equipment such as fans, external forced-oil coolers, or water spray equipment. The amount of additional loading varies widely, depending upon the following:

a) Design characteristics of the transformer
b) Type of cooling equipment
c) Permissible increase in voltage regulation
d) Limitations in associated equipment

No general rules can be given for such supplemental cooling, and each transformer should be considered individually.

The use of water spray equipment for supplemental cooling is not recommended for use in normal loading beyond nameplate rating. Appropriate precautions should be made for the application of water spray equipment for supplemental cooling during emergency overloads. The prevalent problem with water spray cooling is the buildup of scale on the cooling equipment due to minerals in the water. Over the long term, this buildup will hinder the cooling efficiency. The spray and steam generated can also cause phase-to-phase flashover between bushings.

5. Transformer Insulation Life

5.1 General

The subject of loss of transformer insulation life has had a rich, but controversial history of development, with distribution and power transformers taking independent research paths (refer to I.1 in Annex I). As a result of recent studies and testing, the approach to determining insulation loss of life in this guide has been significantly modified (refer to I.2 in Annex I.). The aging or deterioration of insulation is a time function of temperature, moisture, and oxygen. With modern oil preservation systems, the moisture and oxygen contributions to insulation deterioration can be minimized, leaving insulation temperature as the controlling parameter. Since, in most apparatus, the temperature distribution is not uniform, the part operating at the highest temperature ordinarily undergoes the greatest deterioration. Therefore, it is usual to consider the aging effects produced by the highest (hottest spot) temperature in aging studies.

While many factors influence the cumulative effect of temperature over time in causing deterioration of transformer insulation, it is not possible to accurately predict the remaining useful life of the insulation in a transformer. This is even under constant or closely controlled conditions, much less under widely varying service conditions. It is even less possible to predict insulation "life expectancy" according to its common definition of strictly statistical nature. For this reason, in this revision of the guide, the term "life expectancy" is not used. Wherever the word "life" is used in this guide, it means the hypothetical or estimated insulation life(span), not actual transformer life.

5.2 Aging Equations

Experimental evidence indicates that the relation of insulation deterioration and temperature follows an adaptation of the Arrhenius reaction rate theory [B1]. According to the Arrhenius rate equation, the degradation (aging) rate of cellulose insulation can be determined by Equation (1).

$$k = Ae^{\frac{-E_a}{RT}}, \text{ or } k = Ae^{-\frac{B}{T}} \tag{1}$$

where

k	is the rate constant
A	is the pre-exponential factor
$B=E_a/R$	is the slope of the Arrhenius rate plot, K
E_a	is the activation energy of the rate equation, J/mol
R	is the universal gas constant, 8.314 J/(mol K)
T	is thermodynamic temperature, K
e	is the base of natural logarithm

The activation energy, in this equation, is the energy that a molecule must have to participate in the chemical reaction of degradation. In other words, the activation energy is a measure of the effect that temperature has on the aging.

The basis for a temperature limit in North America is given in IEEE Std C57.12.00 [B2]. Per that standard, for thermally upgraded kraft paper (TUK), an acceptable thermal aging performance may be assumed if the insulation system, when tested in accordance with IEEE Std C57.100 [B3], demonstrates a minimum life duration of at least 180,000 hours (approx. 20.5 years), when operated at the hottest-spot temperature equal to 110 °C, at rated load. The minimum acceptable insulation life duration is determined by Equation (2) [IEEE Std C57.12.00], and graphically depicted in Figure 1 as the Arrhenius plot.

$$LIFE = e^{\left(\frac{B}{T_{whs}} - A'\right)} \qquad (2)$$

where

$LIFE$	is insulation life duration
T_{whs}	is thermodynamic temperature (273.15+θ_{whs}), K; (e.g. winding hot spot temperature)
θ_{whs}	winding hottest-spot temperature, °C
e	is the base of natural logarithm
B	is the slop of the Arrhenius rate plot
A'	is a parameter dependent on the end-of-life criteria.

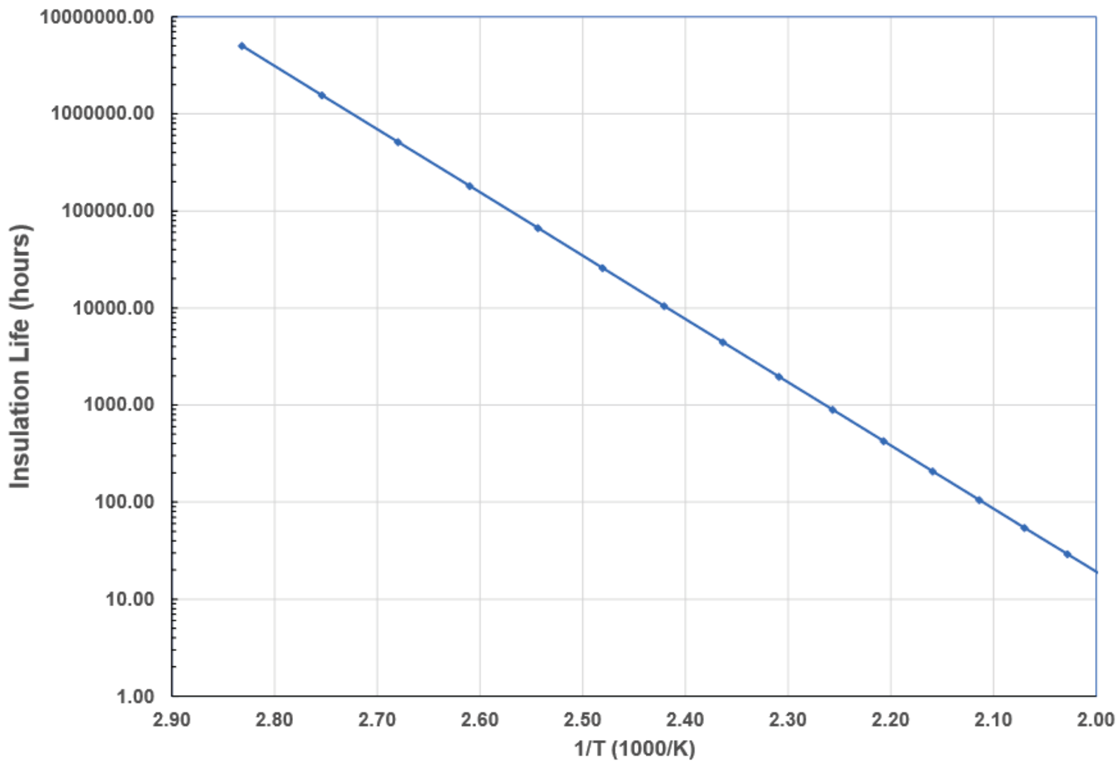


Figure 1— Arrhenius plot of Transformer Insulation Life as defined in IEEE Std C57.12.00, 65ºC average winding rise, 80 ºC hottest-spot rise

For an industry-proven system (IPS) A' = 27.048 and B = 15000 [B3]. The reason for assigning the value of 15000 to B is given in Annex I.2 by analyzing the results of Table I.1.

Parameter A' can be found from Equation (2) by assuming normal insulation LIFE=180,000 hours at θ_{whs}=110 °C => T_{whs}=383.15 K.

Equation (2) can be re-written in the Arrhenius form as:

$$LIFE = A'' e^{\left(\frac{B}{T_{whs}}\right)} \tag{3}$$

where $A'' = e^{-A'}$, or $A'' = 1.8 \cdot 10^{-12}$.

When the logarithms of the hours of life, found by thermal evaluation tests at three or more different temperatures, are plotted against the reciprocals of the absolute temperatures, they will usually, but not always, form a straight line, as shown in Figure 1.

Another common representation of insulation life, as a function of the hottest-spot temperature in degree Celsius, is shown in Figure 2.

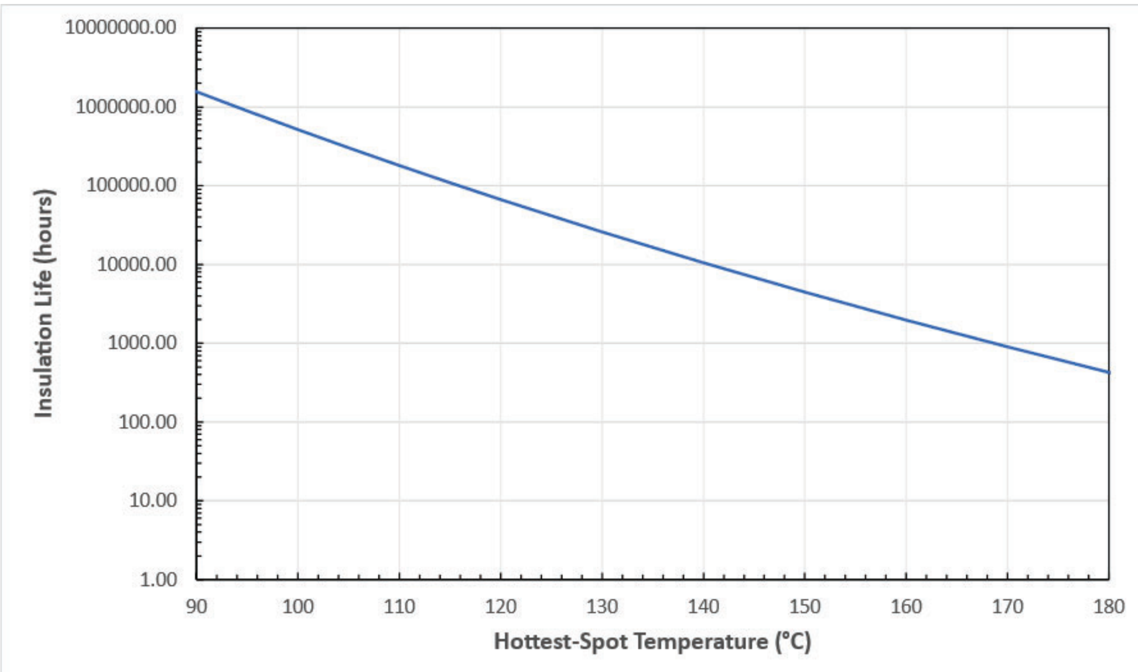


Figure 2— Transformer Insulation Life as a function of the hottest-spot temperature (based on a normal life of 180000 hours at 110 °C)

There is currently no consensus on the insulation life duration or insulation remaining useful life (RUL). Insulation lifespan is dependent on the parameter chosen as the end-of-life criterion (see Annex I, Table I.2) and many other factors. Therefore, it was proposed to use normalized quantity such as per unit life (PUL) to reduce the uncertainty of life duration [B4].

PUL is calculated by assuming that *LIFE* of 180000 hours equals one unit life at the hottest-spot temperature of 110 °C. Thus, Equation (3) can be written as:

$$PUL = A''' e^{\left(\frac{B}{T_{whs}}\right)} \tag{4}$$

where

$A''' = \frac{A''}{180000}$, or $A''' = 9.9 \cdot 10^{-18}$ is almost the same as suggested by McNutt in [B4][7]

The per unit transformer insulation life curve (Figure 3) can be used in two ways. It is the basis for the calculation of an aging acceleration factor (F_{AA}) for a given load and temperature or for a varying load and temperature profile over a 24 h period.

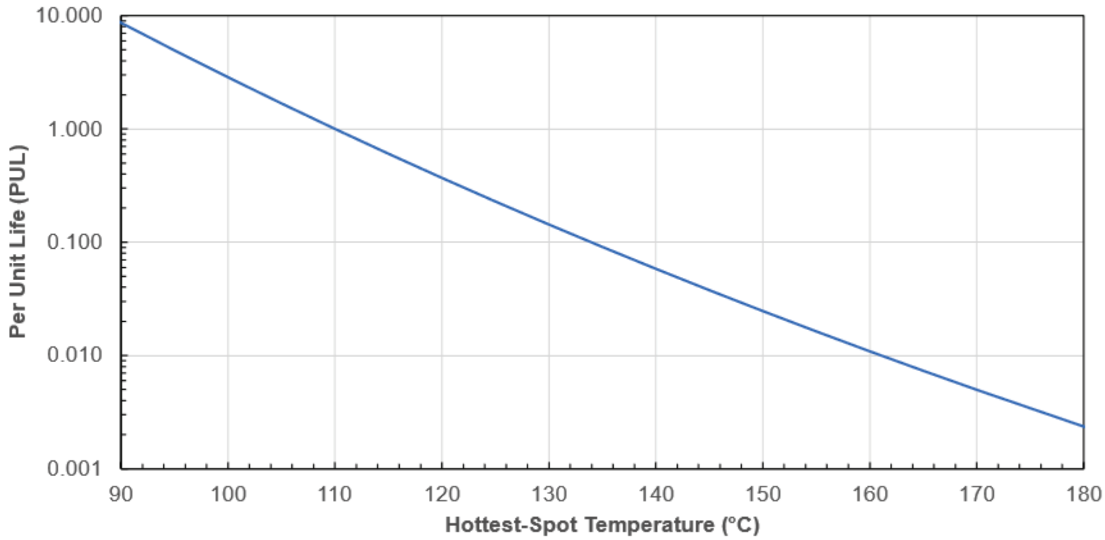


Figure 3— Per Unit Transformer Insulation Life as a function of the hottest-spot temperature

A curve of F_{AA} vs. hottest-spot temperature for a 65 °C rise insulation system is shown in Figure 4, and values are tabulated in Table 1. F_{AA} has a value greater than 1 (one) for winding hottest-spot temperatures greater than the reference temperature 110 °C and less than 1 (one) for temperatures below 110 °C. The Equation for F_{AA} is as follows:

$$F_{AA} = e^{\left(\frac{15000}{383.15} - \frac{15000}{\theta_{whs}+273.15}\right)} \tag{5}$$

where

F_{AA} is aging acceleration factor
θ_{whs} winding hottest-spot temperature, °C

[7] The difference is due to more accurate use of absolute zero temperature equal to -273.15 °C instead of -273 used by McNutt.

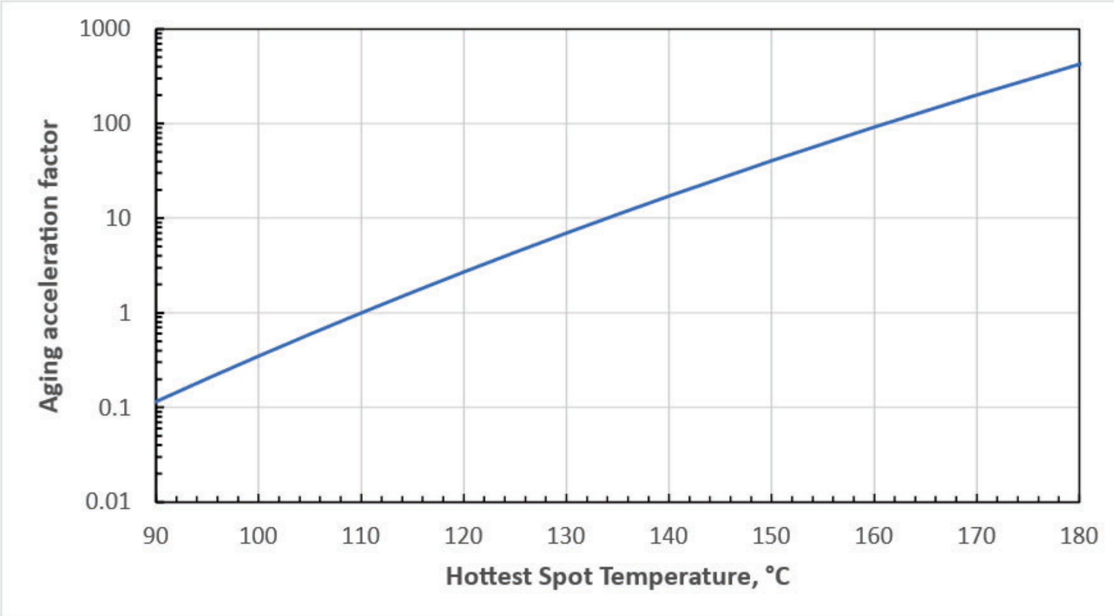


Figure 4— Aging acceleration factor, F_{AA}

Equation (5) is derived by determining relative aging rate by taking ratio of reaction rates (see Equation (1)) at two deferent temperatures θ_{whs} and θ_{whs} =110 °C as:

$$v = \frac{k_1}{k_2} = e^{\left(\frac{15000}{383.15} - \frac{15000}{\theta_{whs}+273.15}\right)} \tag{6}$$

where

- v is the relative aging rate
- k_1 is the aging rate at the hottest-spot temperature of 110 °C
- k_1 is the aging rate at the hottest-spot temperature of θ_{whs} , °C
- θ_{whs} is the winding hottest-spot temperature, °C

Relative aging rate is a term used in IEC loading guide [B8] and CIGRE documents related to insulation life determination.

Equation (5) may be used to calculate equivalent aging of the transformer. The equivalent aging factor over a given time period for the given temperature cycle is the following:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} \tag{7}$$

where

- F_{EQA} is equivalent aging factor for the total time period
- $F_{AA,n}$ is aging acceleration factor for the temperature that exists during the time interval Δt_n
- n is index of the time interval Δt
- Δt_n is the n^{th} time interval during which the aging acceleration factor is calculated, hours

Table 1—Time durations in hours for continuous operation below and above rated hottest spot temperature for different loss of life values

Temperature °C	F_{AA}	Temperature °C	F_{AA}	Temperature °C	F_{AA}
<37	0.0000	91	0.1295	146	28.9315
37	0.0001	92	0.1449	147	31.5115
38	0.0001	93	0.1622	148	34.3015
39	0.0001	94	0.1813	149	37.3215
40	0.0002	95	0.2026	150	40.5915
41	0.0002	96	0.2263	151	44.1315
42	0.0002	97	0.2526	152	47.9615
43	0.0002	98	0.2817	153	52.1015
44	0.0003	99	0.3141	154	56.5815
45	0.0003	100	0.3499	155	61.4215
46	0.0004	101	0.3897	156	66.6516
47	0.0004	102	0.4337	157	72.3016
48	0.0005	103	0.4823	158	78.3916
49	0.0006	104	0.5362	159	84.9716
50	0.0007	105	0.5957	160	92.0616
51	0.0008	106	0.6614	161	99.7116
52	0.0009	107	0.7340	162	107.9616
53	0.0011	108	0.8142	163	116.8416
54	0.0012	109	0.9026	164	126.4116
55	0.0014	110	1.0000	165	136.7216
56	0.0016	111	1.1074	166	147.8117
57	0.0019	112	1.2256	167	159.7517
58	0.0021	113	1.3558	168	172.5817
59	0.0024	114	1.4990	169	186.3917
60	0.0028	115	1.6565	170	201.2317
61	0.0032	116	1.8296	171	217.1817
62	0.0037	117	2.0197	172	234.3017
63	0.0042	118	2.2285	173	252.7017
64	0.0048	119	2.4576	174	272.4517
65	0.0054	120	2.7089	175	293.6417
66	0.0062	121	2.9845	176	316.3718
67	0.0071	122	3.2865	177	340.7518
68	0.0080	123	3.6172	178	366.8918
69	0.0091	124	3.9793	179	394.9118
70	0.0104	125	4.3756	180	424.9218
71	0.0118	126	4.8091	181	457.0718
72	0.0134	127	5.2830	182	491.5018
73	0.0152	128	5.8009	183	528.3518
74	0.0172	129	6.3665	184	567.7818
75	0.0195	130	6.9842	185	609.9618
76	0.0220	131	7.6582	186	655.0819
77	0.0249	132	8.3935	187	703.3119
78	0.0281	133	9.1952	188	754.8619
79	0.0318	134	10.0689	189	809.9419
80	0.0358	135	11.0208	190	868.7719
81	0.0404	136	12.0573	191	931.6019
82	0.0455	137	13.1856	192	998.6719
83	0.0513	138	14.4131	193	1070.2519
84	0.0577	139	15.7481	194	1146.6219
85	0.0649	140	17.1994	195	1228.0819
86	0.0729	141	18.7765	196	1314.9420
87	0.0819	142	20.4895	197	1407.5420
88	0.0919	143	22.3493	198	1506.2220
89	0.1031	144	24.3679	199	1611.3520
90	0.1156	145	26.5578	200	1723.3420

5.3 Percent loss of life

The insulation per unit life curve (Figure 4) can also be used to calculate the percent loss of total life, as has been the practice in earlier editions of the referenced transformer loading guides. To do so, it is necessary to arbitrarily define the normal insulation life at the reference temperature in hours or years. Benchmark values of normal insulation life for a well-dried, oxygen-free system can be selected from Table I.2. The hours of life lost in the total period is then determined by multiplying the equivalent aging determined in Equation (4) by the time period (t) of interest in hours. This provides the equivalent hours of life at the reference temperature that are consumed in the period t. Percent loss of insulation life (*%LoL*) during the period t is equivalent hours life consumed divided by the normal insulation life (h) and multiplied by 100. Frequently, the period of interest is 24 h. The Equation is given as follows:

$$\%LoL = \frac{F_{EQA} \times t \times 100}{LIFE} \tag{8}$$

where

$\%LoL$ is percent loss of life
F_{EQA} is equivalent aging factor for the t time
t is the period during which loss of life is estimated
$LIFE$ is the normal insulation life as determined by Equation (2)

Per 5.11.3 of IEEE Std C57.12.00-2010, a minimum acceptable insulation life of 180,000 hours is required. Other values for the end-of-life criteria have been used historically for developing transformer loading capability studies. The equations provided in this clause include a variable for the end-of-life criteria, so those users who have used alternative values may continue to do so. The end-of-life criteria are described in Table I.2 of Annex I.

The time duration for continuous operation at the hottest spot temperatures above rated that give different percent loss of life may be calculated using Equation (8). Table 1 gives time durations for various loss of life based on a normal life of 180,000 hours. Normal percent loss of life for operation at a rated hottest spot temperature of 110 °C for 24 h is 0.0133%.

Table 2—Time durations in hours for continuous operation above rated hottest spot temperature for different loss of life values

Hottest spot temp °C	F_{AA}	Percent loss of life[a]						
		0.0133 [b]	0.02	0.05	0.1	0.2	0.3	0.4
110	1.00	24	—	—	—	—	—	—
120	2.71	8.86	13.3	—	—	—	—	—
130	6.98	3.44	5.1	12.9	—	—	—	—
140	17.2	1.39	2.1	5.2	10.5	20.9	—	—
150	40.6	0.59	0.89	2.2	4.4	8.8	13.3	17.7
160	92.1	0.26	0.39	0.98	1.96	3.9	5.9	7.8
170	201.2	0.12	0.18	0.45	0.89	1.8	2.7	3.6
180	424.9	0.06	0.08	0.21	0.42	0.84	1.27	1.7
190	868.8	0.028	0.04	0.10	0.21	0.41	0.62	0.82
200	1723	0.014	0.02	0.05	0.10	0.21	0.31	0.42

[a] Based on a normal life of 180,000 hours. Time durations not shown are in excess of 24 hours.

[b] This column of time durations for 0.0133% loss of life gives the hours of continuous operation above the basis-of-rating hottest spot temperature (110 °C) for one equivalent day of operation at 110 °C.

An example of the loss of life calculation is given in Annex I.

As mentioned, in addition to temperature, transformer insulation life is affected by moisture and oxygen. A theoretical background on the impact of moisture and oxygen on cellulose insulation can be found in [B5]. Laboratory aging tests were conducted by the EPRI sponsored research [B6], [B7], where it was demonstrated that aging of transformer insulation is highly dependent on moisture and oxygen content. If both are low, thermal degradation is minimal except with very high temperatures.

The reports [B6], [B7] clearly show that insulation degradation is most severe in paper-oil systems with high moisture and oxygen contents, which are a replica of air-breathing/free-breathing, conservator units. Insulation degradation is somewhat less severe in oxygen-free paper-oil systems, and much less severe in dry and oxygen-free paper-oil systems, which are a replica of either conservator units with membranes or nitrogen-blanketed units.

Maintaining low moisture and oxygen contents is an effective strategy for extending insulation life and increasing transformer operating life. The reports concluded that monitoring and continuous oil filtration on-line are methods to address this. The results of the EPRI work were used in the development of the insulation aging model relating cellulose degradation rate to temperature, oxygen, and moisture. The latest revision of IEC 60076-7-2018 [B8] includes this model to provide the user with means to estimate an effect of moisture and oxygen on transformer insulation life.

6. Ambient temperature and its influence on loading

6.1 General

Ambient temperature is an important factor in determining the load capability of a transformer since the temperature rises for any load must be added to the ambient temperature to determine accurate operating temperatures. Transformer ratings are based on a 24 h average ambient temperature of 30 °C—the standard ambient temperature used in this guide. Whenever the actual ambient temperature can be measured, ambient temperatures should be averaged over 24 h, and then used in determining the transformer's temperature and loading capability. The ambient air temperature experienced by a transformer is the air in contact with its radiators or heat exchangers. In some installations, the transformer may be outdoors, but surrounded by buildings, firewalls, or sound deadening walls. This may result in recirculation of air (less efficient cooling), and the average ambient temperature should be adjusted accordingly.

6.2 Approximating ambient temperature for air-cooled transformers

It is often necessary to predict the load that a transformer can safely carry, at some future time, in an unknown ambient temperature. The probable ambient temperature for any month may be approximated from data in reports prepared by the national or local atmospheric authority for the sections of the country where the transformer is located.

a) *Average temperature*. Use average daily temperature for the month involved, averaged over several years.

b) *Maximum daily temperature*. Use average of the maximum daily temperatures for month involved averaged over several years.

These ambient temperatures should be used as follows:

— For loads with normal estimated life, use a), the average temperature as the ambient for the month involved.

— For short-time loads with moderate sacrifice of estimated life, use b), the maximum daily temperature for the month involved.

During any one day, the 24 h average of temperature may exceed the value derived from a) or b) above. To be conservative, it is recommended that these temperatures be increased by 5 °C since aging at higher-than-average temperature is not fully compensated by decreased aging at lower-than-average temperature. With this margin, the approximated 24 h average temperature will not be exceeded on more than a few days per month and, where it is exceeded, the additional loss of life should not be significantly detrimental.

6.3 Approximating ambient temperature for water-cooled transformers

The ambient temperature to be used for water-cooled transformers is the cooling water temperature plus an additional 5 °C. This additional temperature is included to allow for a possible loss of cooling efficiency due to deposits on cooling coil surfaces of water-cooled transformers in service.

6.4 Influence of ambient temperature on loading for normal estimated life

Average ambient temperatures should cover 24 h time periods. The associated maximum temperatures should not be more than 10 °C above the average temperatures for air-cooled, and 5 °C for water-cooled transformers. Since ambient temperature is an important factor in determining the load capability of a transformer, it should be controlled for indoor installations by adequate ventilation and should always be considered in outdoor installations.

Table 3 provides the deviations in rated kVA for other than average daily ambient temperatures of 30 °C for air and 25 °C for water. It is recommended that a 5 °C margin be used when applying the factors from Table 3. It should be noted that the increase or decrease obtained from Table 3 is conservative, and therefore, do not match exactly with the calculations using the equations in Clause 7. Table 3 is for approximation only. Loading based on ambient temperature with loads permitted in Table 3 will provide approximately the same estimated life as if transformers were operated at nameplate rating and standard ambient temperatures over the same period. Table 3 covers a range in average ambient temperatures of –30 °C to 50 °C for cooling air. A check with the manufacturer should be made before loading when the ambient air temperature is less than –30 °C or greater than 50 °C.

CAUTION
Loading of power transformers for ambient conditions requires calculations. Table 3 should not be used for actual planning or operational limits.

Table 3—Loading on basis of temperatures (average ambient temperature other than 30 °C and average winding rise less than limiting values) (for quick approximation) (ambient temperature range –30 °C to 50 °C)

Type of cooling	% of kVA rating	
	Decrease load for each °C higher temperature	Increase load for each °C lower temperature
Self-cooled—ONAN	1.5	1.0
Water-cooled—ONWF	1.5	1.0
Forced-air-cooled—ONAN/ONAF, ONAN/ONAF/ONAF	1.0	0.75
Forced-oil, -air, -water-cooled—ODAF, OFAF, OFWF, ODWF, and ONAN/OFAF/OFAF	1.0	0.75

7. Thermal models used for transformer loading and prediction of insulation life

General

The objective of reliable transformer operation is to allow its loading to the maximum extent without significantly compromising its integrity and causing undue risk of failure or accelerated aging of its insulation. To achieve this objective, critical temperatures must be measured, predicted, and acted upon. From the previous sections, it follows that the insulation life of a transformer is affected by operating temperatures. For that reason alone, there is an ever-increasing need for reliable measurements and estimations of transformer critical temperatures. In the field of technology and engineering, estimation of temperatures using data, physical laws, and advances in computational science is known as thermal modeling.

Annex J presents the historical background, recent developments, and some examples of thermal models used in practice to predict transformer remaining insulation life (RUL) and loading capability of mineral-oil-immersed transformers.

This section describes two approaches to transformer thermal modeling based on Annex G (called herein the Pierce model) and Clause 7 (called the Montsinger-Cooney model) of the previous edition of Loading Guide [B9].

It is worth mentioning that there are many other practical use cases where transformer thermal models play a critical role. Among these applications are:

- Compliance with the temperature limits specified in industry standards and guidelines
- Validation of temperature rise guarantee
- Prediction of loading/overloading capability
- Prediction of accelerated aging
- Prediction of bubble evolution temperature
- Estimation of thermal performance

— Design and execution of thermal protection
— Optimization of cooling control
— Monitoring of cooling efficiency
— Assessment of moisture distribution within solid insulation
— Prediction of dielectric integrity of oil at cold load pick up
— Estimation of risk of failure related to a combination of moisture and temperature effects on transformer operation
— Assessment of impact from geomagnetically induced current (GIC)
— Determination of facility and HV equipment static and dynamic ratings

This list is not exhaustive, and more applications can be envisioned with further proliferation of distributed energy resources (DER), where an impact of two-directional power flow and non-linear load on transformer thermal performance will be increasingly more pronounced.

7.1 Governing Equations

The governing equations for a transformer dynamic thermal model include fundamental Maxwell equations (electromagnetic field model), coupled with Navier-Stokes equations (fluid dynamics model).

The transformer internal oil flow can be modeled by the mass, the momentum, and the energy conservation equations [B10] as given in the sections below.

7.1.1 Conservation of mass

$$\frac{\partial \rho}{\partial t} + \nabla \cdot (\rho \mathbf{v}) = 0 \qquad (9)$$

where

ρ is the density of fluid (mass per unit volume)
t is the time
∇ is the divergence symbol
$\mathbf{v}$ is the fluid flow velocity field

7.1.2 Conservation of momentum

$$\frac{\partial}{\partial t}(\rho \mathbf{v}) + \nabla \cdot (\rho \mathbf{v} \otimes \mathbf{v}) = -\nabla \bar{p} + \mu \nabla^2 \mathbf{v} + \rho \mathbf{g} \qquad (10)$$

where

ρ is the density of fluid (mass per unit volume),
p is the pressure
t is the time
∇ is the divergence symbol
g is the gravitational acceleration

$\mathbf{v}$ is the fluid flow velocity field.
$\boldsymbol{\mu}$ is the viscosity of the fluid

7.1.3 Conservation of energy

The state equation, given by the first law of thermodynamics (i.e., conservation of energy), is written in the following form (assuming no mass transfer or radiation):

$$\rho c_p \frac{\partial T}{\partial t} - \nabla \cdot (k \nabla T) = \dot{q}_V, \tag{11}$$

where

ρ is the density of fluid (mass per unit volume),
t is the time
k is the thermal conductivity
∇T is the temperature gradient
$\mathbf{v}$ is the fluid flow velocity field.
$\dot{q}_V$ is the volumetric heat source.

The solution of the above set of equations requires significant computational power and knowledge of detailed design parameters of a transformer. This presents a significant challenge and limits the application of the above equations to a transformer design stage only.

7.2 Simplified thermal models

In practice, severely simplified thermal models have been used for loading, prediction of remaining useful life, and online condition monitoring.

The simplification is often based on the following assumptions [B11], [B12]

- The oil temperature in the cooling duct exit is assumed to be the same as the top oil temperature.
- The change in winding resistance with temperature is neglected.
- The change in oil viscosity with temperature is neglected.
- The effect of tap position is neglected.
- The variation of ambient temperature is assumed to have an immediate effect on oil temperature.
- The heating and cooling of a transformer can be modeled based on an analogy with charging and discharging a capacitor of the electrical circuit.
- A lumped-capacitance model is valid throughout the thermal modeling process
- Temperature rise test parameters can be directly used in the development of thermal models for loading estimation in the field.
- The conductive heat transfer within windings and core is neglected
- The external energy due to environmental factors, such as sun radiation, wind speed, relative humidity, etc. is neglected.

Many times, it has been demonstrated that these assumptions may lead to unsatisfactory results and erroneous conclusions [B13]. Therefore, alternative set of equations for use in transformer loading analysis have been developed, considering majority of the factors above [B14,], [B15].

The following thermal model equations are based on the former Annex G [9] formulation and modified Clause 7 top oil model [9].

7.2.1 List of symbols

Symbol	Meaning	Unit
C	thermal capacitance	J/K
c	specific heat	J/(kg·K)
c_{pw}	winding specific heat	J/(kg·K)
$c_{p,oil}$	specific heat of oil	J/(kg·K)
H_{whs}	per unit of winding height to hotspot location	p.u.
K	ratio of observed load to rated load	p.u
K_w	temperature correction factor for winding losses	p.u.
K_{whs}	temperature correction factor for losses at hotspot location	p.u.
E_{whs}	eddy loss at winding hotspot location, per unit of I^2R loss	W
$P_{e,r}$	eddy loss of windings at rated load	W
$P_{w,r}$	winding I^2R loss at rated load	W
$P_{ehs,r}$	eddy loss at rated load and rated winding hotspot temperature	W
P_{whs}	winding I^2R loss at rated load and rated hotspot temperature	W
$P_{c,r}$	core (no-load) loss	W
$P_{c,oe}$	core loss when overexcitation occurs	W
$P_{s,r}$	stray losses at rated load	W
P_{tot}	total losses at rated load	W
m_w	winding mass	kg
m_{cc}	core and coil (untanking) weight	kg
m_{core}	mass of the core	kg
m_{oil}	mass of oil	kg
m_{tank}	mass of tank	kg
m	exponent for alternative winding hottest-spot model	
n	oil exponent for alternative top oil model	
$\dot{Q}_{ext}$	rate at which thermal energy is supplied to the transformer from outside	W
$\dot{Q}_{lost}$	rate at which thermal energy leaves the transformer	W
$\dot{Q}_{gen}$	rate at which thermal energy is generated within the transformer	W
$\dot{Q}_{gen,w}$	rate of heat generation by the windings	W
$\dot{Q}_{lost,w}$	rate of heat dissipation by the winding	W
$\dot{Q}_{lost,whs}$	heat dissipation rate for hotspot calculation	W
$\dot{Q}_{lost,o}$	heat dissipation rate from oil to air	W
$\dot{Q}_{gen,whs}$	rate of heat generation at winding hotspot location	W
$\dot{Q}_{gen,c}$	rate of heat generation by core	W
$\dot{Q}_{gen,s}$	rate of heat generation due to stray losses	W
θ	bulk transformer temperature	°C
θ_k	reciprocal of the temperature coefficient of conductor resistance: 234.5 for copper, 225.0 for aluminum	°C
θ_{aw}	average winding temperature	°C
$\theta_{aw,r}$	average winding temperature at rated load	°C

θ_{ado}	average oil temperature in the cooling ducts	°C
$\theta_{ado,r}$	average oil temperature in the cooling ducts at rated load	°C
θ_{bo}	bottom oil temperature	°C
$\theta_{bo,r}$	bottom oil temperature at rated load	°C
θ_{tdo}	oil temperature at top of cooling duct	°C
$\Theta_{tdo,r}$	oil temperature at top of cooling duct at rated load	°C
θ_{ohs}	temperature of the oil adjacent to winding hotspot – the oil hottest-spot temperature	°C
θ_{to}	top oil temperature in tank and radiator	°C
θ_{whs}	winding hotspot temperature	°C
$\theta_{whs,r}$	winding hotspot temperature at rated load	°C
θ_{ao}	average oil temperature in tank and radiator	°C
$\Delta\theta_{whs/to,r}$	temperature rise of winding temperature over top oil temperature at rated load	
$\Delta\theta_{tdo/bo}$	temperature rise of oil at top of duct over bottom oil	K
$\Delta\theta_{ohs/bo}$	temperature rise of oil adjacent to winding hotspot over bottom oil	K
$\Delta\theta_{tdo/bo}$	temperature rise of top-duct oil over bottom oil temperature	K
$\Delta\theta_{to/bo}$	temperature rise of oil at top of tank/radiator over bottom oil in the tank or radiator	K
$\Delta\theta_{to/a,r}$	temperature rise of top oil over ambient temperature at rated load,	K
x	exponent for duct oil rise over bottom oil, and is 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF	-
y	exponent of average oil rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF	
z	exponent for top to bottom oil temperature difference and is 0.5 for ONAN and ONAF; 1.0 for OFAF and ODAF	
Greek letters		
μ	viscosity of the oil	Pa·s
μ_r	viscosity of the oil for the average winding temperature rise at rated load	Pa·s
μ_{ohs}	dynamic viscosity of oil at hotspot location, cP	Pa·s
$\mu_{ohs,r}$	dynamic viscosity of oil at hotspot location at rated load, cP	Pa·s
τ_W	winding time constant	min
τ_{to}	time constant for top oil	min

7.2.2 Transient temperature equations

As mentioned above, the winding and oil temperature equations are derived in [B14],[B15] and are included in Annex G of the IEEE Loading Guide from 2012 [B9]. In those references, thermal models were created based on the first law of thermodynamics considering the balance of energy changes over a time interval (Δt).

According to the law of conservation of energy for such an interval, the increase in the amount of energy stored in a control volume must equal the amount of energy that enters the control volume, minus the amount of energy that leaves the control volume, plus the amount of energy that is generated within the control volume. All the energy terms are measured in joules (W·s). with the control volume being a transformer with its cooling system and other ancillary parts, inclusive.

In general, the first law of thermodynamics must be satisfied at each instance of time t; thus, we can also formulate the law on the rate basis in the continuous form [B16]. According to that formulation with reference to a transformer:

The rate of increase of thermal energy stored in the transformer and its components must equal the rate at which thermal energy is supplied to the transformer from outside, minus the rate at which thermal energy leaves the transformer, plus the rate at which thermal energy is generated within the transformer.

In mathematical terms:

$$C\frac{d\theta}{dt} = \dot{Q}_{ext} - \dot{Q}_{lost} + \dot{Q}_{gen} \tag{12}$$

where

$\dot{Q}_{ext}$ is the rate at which thermal energy is supplied to the transformer from outside, W
$\dot{Q}_{lost}$ is the rate at which thermal energy leaves the transformer, W
$\dot{Q}_{gen}$ is the rate at which thermal energy is generated within the transformer, W
C is the thermal capacitance, J/K
θ is the bulk transformer temperature, °C

All the energy rates terms are measured in Watts (W). This is the same unit used for power loss calculation and measurement. The system of equations constitutes a set of algebraic and differential equations. This way, the system of equations can be solved by any known numerical method without sacrificing accuracy. Having a model written in the form of differential and algebraic equations allows a comparison of this model with other frequently used models, e.g. [B13],[B17], [B18], [B19,] [B20], and [B21]. It also allows a comparison with the older models included in Clause 7 of [B9]. Corrections for change of oil viscosity and electrical resistance with temperature are incorporated into the set of these equations.

The system of loading equations is based on the oil flow occurring in the transformer during transient conditions. The steady-state equations can be easily obtained by assuming constant load and ambient temperature in Equation (12). In this case, there will be no change in the thermal energy stored in a transformer.

7.2.3 Determination of average winding temperature

Following Equation (12) the average winding temperature is determined by solving differential Equation (13):

$$m_w c_{pw}\frac{d\theta_{aw}}{dt} = \dot{Q}_{gen,w} - \dot{Q}_{lost,w} \tag{13}$$

where

$\dot{Q}_{gen,w}$ is the rate of heat generation by the windings, W
$\dot{Q}_{lost,w}$ is the rate of heat dissipation from winding, W
θ_{aw} is the average winding temperature, °C
$m_w c_{pw}$ is thermal capacitance, J/K

The rate of heat generation by the windings is:

$$\dot{Q}_{gen,w} = K^2\left[P_{w,r}K_w + \frac{P_{e,r}}{K_w}\right], \tag{14}$$

where

$\dot{Q}_{gen,w}$ is the rate of heat generation by the windings, W
K is the ratio of load (current or apparent power) to rated load, p.u.
K_w is the temperature correction factor for winding losses, p.u.
$P_{e,r}$ is the eddy loss of windings at rated load, W
$P_{w,r}$ is the winding I^2R loss at rated load, W

Temperature correction factor for winding losses is determined by Equation (15)

$$K_w = \frac{\theta_{aw} + \theta_k}{\theta_{aw,r} + \theta_k} \tag{15}$$

where

K_w is the temperature correction factor for winding losses
θ_k is the reciprocal of the temperature coefficient of conductor resistance: 234.5 for copper, 225.0 for aluminum, °C
θ_{aw} is the average winding temperature, °C
$\theta_{aw,r}$ is the average winding temperature at rated load, °C

The rate of heat dissipation by the winding for the ONAN, ONAF, and OFAF cooling modes, also known as the rate of heat, lost by the windings is:

$$\dot{Q}_{lost,w} = \left[\frac{\theta_{aw} - \theta_{ado}}{\theta_{aw,r} - \theta_{ado,r}}\right]^{1.25} \left[\frac{\mu_r}{\mu}\right]^{0.25} (P_{w,r} + P_{e,r}) \tag{16}$$

where

$P_{e,r}$ is the eddy current loss of the windings at rated load, W
$P_{w,r}$ is the winding I^2R loss at rated load, W
$\dot{Q}_{lost,w}$ is the rate of heat dissipation by the winding, W
θ_{ado} is the average oil temperature in the cooling ducts, °C
$\theta_{adao,r}$ is the average oil temperature in the cooling ducts at rated load, °C
θ_{aw} is the average winding temperature, °C
$\theta_{aw,r}$ is the average winding temperature at rated load, °C
μ is the viscosity of the oil for the temperature defined in Table [viscosity table] [kg/(s·m)] [Pa·s]
μ_r is the viscosity of the oil for the average winding temperature rise at rated load, cP [kg/(s·m)] [Pa·s]

The viscosity μ is evaluated at a temperature given in Table 1.

Considering that no viscosity correction is needed for the forced directed oil flow, the heat lost by the winding in ODAF is:

$$\dot{Q}_{lost,w} = \left[\frac{\theta_{aw} - \theta_{ado}}{\theta_{aw,r} - \theta_{ado,r}}\right] (P_{w,r} + P_{e,r}) \tag{17}$$

where

$P_{e,r}$ is the eddy loss of windings at rated load, W
$P_{w,r}$ is the winding I^2R loss at rated load, W
$\dot{Q}_{lost,w}$ is the rate of heat dissipation by the winding, W
θ_{ado} is the average temperature of oil in cooling ducts, °C

$\theta_{ado,r}$ is the average temperature of oil in cooling ducts at rated load, °C
θ_{aw} is the average winding temperature, °C
$\theta_{aw,r}$ is the average winding temperature at rated load tested, °.

The average temperature of oil in cooling ducts is calculated according to Equation (18):

$$\theta_{ado} = (\theta_{tdo} - \theta_{bo})/2 \tag{18}$$

where

θ_{ado} is the average temperature of oil in cooling ducts, °C
θ_{tdo} is the temperature of oil at the top of cooling duct, °C
θ_{bo} is the bottom oil temperature, °C

The mass and thermal capacitance of the windings may be estimated from the winding time constant. The winding time constant may be determined from the cooling curves obtained during factory heat run testing, or approximate values may be used. From the definition of a time constant for exponential heating or cooling the $m_w c_{pw}$ term may be determined from Equation (19).

$$m_w c_{pw} = \frac{(P_{w,r} + P_{e,r})\tau_w}{\theta_{w,r} - \theta_{adao,r}} \tag{19}$$

where

m_w is the winding mass, kg
c_{pw} is the winding specific heat, (J/(kg·K)
$P_{e,r}$ is the eddy loss of windings at rated load, W
$P_{w,r}$ is the winding I^2R loss at rated load, W
$\theta_{ado,r}$ is the average temperature of oil in cooling ducts at rated load, °C
$\theta_{w,r}$ is the winding temperature at rated load, °C
τ_w is the winding time constant, min

Substituting the rates of heat generation and heat dissipation from (14), (16), and (17) respectively in (13) results in:

$$m_w c_{pw} \frac{d\theta_{aw}}{dt} = K^2 \left[P_{w,r} K_w + \frac{P_{e,r}}{K_w}\right] - \left[\frac{\theta_{aw} - \theta_{ado}}{\theta_{ma,r} - \theta_{ado,r}}\right]^{1.25} \left[\frac{\mu_{w,r}}{\mu_w}\right]^{0.25} (P_{w,r} + P_{e,r}) \tag{20}$$

where

m_w is the winding mass, (kg)
θ_{aw} is the average winding temperature, °C
c_{pw} is the winding specific heat, (J/(kg K)
$\dot{Q}_{gen,w}$ is the rate of heat generation by the windings, W
$\dot{Q}_{lost,w}$ is the rate of heat dissipation from the winding, W
μ_w is the viscosity of the oil for the temperature defined in Table [viscosity table] [kg/(s·m)] [Pa·s]
$\mu_{w,r}$ is the viscosity of the oil for the average winding temperature rise at rated load, cP [kg/(s·m)] [Pa·s]

Considering that no viscosity correction is needed for the forced directed oil flow the heat lost by the winding in ODAF is:

$$m_w c_{pw} \frac{d\theta_{aw}}{dt} = K^2 \left[P_{w,r} K_w + \frac{P_{e,r}}{K_w}\right] - \left[\frac{\theta_{aw} - \theta_{ado}}{\theta_{ma,r} - \theta_{ado,r}}\right]^{1.0} (P_{w,r} + P_{e,r}) \tag{21}$$

where

- m_w is the winding mass, (kg)
- θ_{aw} is the average winding temperature, °C
- c_{pw} is the winding specific heat, (J/(kg K)
- $\dot{Q}_{gen,w}$ is the rate of heat generation by the windings, W
- $\dot{Q}_{lost,w}$ is the rate of heat dissipation from the winding, W

7.2.4 Determination of the winding top-of-duct oil temperature rise over bottom oil temperature

The duct oil temperature rise over bottom oil temperature is determined according to Equation (22).

$$\Delta\theta_{tdo/bo} = \theta_{tdo} - \theta_{bo} = \left[\frac{Q_{lost,w}}{P_{w,r} + P_{e,r}}\right]^x (\theta_{tdo,r} - \theta_{bo,r}) \tag{22}$$

where

- $P_{e,r}$ is the eddy loss of windings at rated load, W
- $P_{w,r}$ is the winding I^2R loss at rated load, W
- $\dot{Q}_{lost,w}$ is the rate of heat dissipation from winding, W
- x is the exponent for duct oil rise over bottom oil, and is 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF
- θ_{bo} is the bottom oil temperature, °C
- $\theta_{bo,r}$ is the bottom oil temperature at rated load, °C
- θ_{tdo} is the oil temperature at top of duct, °C
- $\theta_{tdo,r}$ is the oil temperature at top of duct at rated load, °C
- $\Delta\theta_{tdo/bo}$ is the temperature rise of oil at top of duct over bottom oil temperature, °C

For the ONAN, ONAF, and ODAF cooling modes the duct top-oil temperature at rated load, $\theta_{tdo,r}$ is assumed equal to the tank top oil temperature. For non-directed OFAF, if the duct top-oil temperature at rated load is not known, it can be assumed to be approximately equal to the average winding temperature at rated load (based on an analysis of the data reported in [B22].

In [B22], it is suggested that the hotspot may not be located at the top of the winding. The oil temperature at the hotspot elevation is given by:

$$\Delta\theta_{ohs/bo} = H_{whs}(\theta_{tdo} - \theta_{bo}) \tag{23}$$

$$\theta_{ohs} = \theta_{bo} + \Delta\theta_{ohs/bo} \tag{24}$$

where

- H_{whs} is the per unit of winding height to hotspot location

θ_{bo} is the bottom oil temperature, °C
θ_{tdo} is the oil temperature at top of the duct, °C
θ_{ohs} is the oil hotspot - temperature of the oil adjacent to winding hotspot, °C
$\Delta\theta_{ohs/bo}$ is the temperature rise of oil at winding hotspot location over bottom oil, °C

When the calculated winding top-of-duct oil temperature is less than the top oil in the tank, the oil temperature adjacent to the hotspot is assumed equal to the top oil temperature since the upper portion of the winding may be in contact with the hotter top oil. The equation is as follows:

$$\text{If } \theta_{tdo} < \theta_{to}\text{, then } \theta_{ohs} = \theta_{tdo} = \theta_{to}, \tag{25}$$

where

θ_{tdo} is the oil temperature at top of duct, °C
θ_{to} is the top oil temperature in tank and radiator, °C
θ_{ohs} is the temperature of the oil adjacent to winding hotspot, °C

7.2.5 Determination of winding hotspot temperature

To account for the additional heat generated at the hotspot temperature, it is necessary to correct the winding losses from the average winding temperature to the hotspot temperature. As with average winding temperature the conservation of energy equation for the hottest winding temperature is as follows:

$$m_w c_p \frac{d\theta_{whs}}{dt} = \dot{Q}_{gen,whs} - \dot{Q}_{lost,whs} \tag{26}$$

where

$\dot{Q}_{gen,whs}$ is the heat generation rate at winding hotspot location, W.
$\dot{Q}_{lost,whs}$ is the heat dissipation rate for hotspot calculation, W
θ_{whs} is the winding hotspot temperature, °C
$m_w c_p$ is the thermal capacitance, J/K

$$P_{whs,r} = \left(\frac{\theta_{whs,r}+\theta_k}{\theta_{aw,r}+\theta_k}\right) P_{w,r} \tag{26}$$

$$P_{ehs,r} = E_{whs} P_{whs,r} \tag{27}$$

where

E_{whs} is the eddy loss at winding hotspot location, per unit of I^2R loss
$P_{ehs,r}$ is the eddy loss at rated load and rated winding hotspot temperature, W
$P_{whs,r}$ is the winding I^2R loss at rated load and rated hotspot temperature, W
$P_{w,r}$ is the winding I^2R loss at rated load, W
θ_k is the temperature factor for resistance correction, °C
$\theta_{whs,r}$ is the winding hotspot temperature at rated load, °C
$\theta_{aw,r}$ is the average winding temperature at rated load tested, °C

If E_{whs} is not known, it may be estimated; however, as being equal to or greater than $P_{e,r}$ divided by $P_{w,r}$.

$$\dot{Q}_{gen,whs} = K^2 \left[P_{whs,r} K_{whs} + \frac{P_{ehs,r}}{K_{whs}}\right] \tag{28}$$

where

K is the ratio of load to rated load, per unit
K_{whs} is the temperature correction for losses at hotspot location, per unit
$P_{ehs,r}$ is the eddy loss at rated load and rated winding hotspot temperature, W
$P_{whs,r}$ is the winding I^2R loss at rated load and rated hotspot temperature, W
$\dot{Q}_{gen,whs}$ is the heat generation rate at winding hotspot location, W.

where

$$K_{whs} = \frac{\theta_{whs} + \theta_k}{\theta_{whs,r} + \theta_k} \tag{29}$$

where

K_{whs} is the temperature correction for losses at hotspot location, per unit
θ_k is the reciprocal of the temperature coefficient of conductor resistance: 234.5 for copper, 225.0 for aluminum, °C
θ_{whs} is the winding hotspot temperature, °C
$\theta_{whs,r}$ is the winding hotspot temperature at rated load, °C

For the ONAN, ONAF, and OFAF cooling modes, the heat lost at the hotspot location is given by:

$$\dot{Q}_{lost,whs} = \left[\frac{\theta_{whs} - \theta_{ohs}}{\theta_{whs,r} - \theta_{ohs,r}}\right]^{5/4} \left[\frac{\mu_{ohs,r}}{\mu_{ohs}}\right]^{1/4} (P_{whs,r} + P_{ehs,r}) \tag{30}$$

where

$P_{ehs,r}$ is the eddy loss at rated load and rated winding hotspot temperature, W
$P_{whs,r}$ is the winding I^2R loss at rated load and rated hotspot temperature, W
$\dot{Q}_{lost,whs}$ is the heat dissipation rate for hotspot calculation, W
θ_{whs} is the winding hotspot temperature, °C
$\theta_{whs,r}$ is the winding hotspot temperature at rated load °C
θ_{ohs} is the temperature of oil adjacent to winding hotspot, °C
$\theta_{ohs,r}$ is the temperature of oil adjacent to winding hotspot at rated load, °C
μ_{ohs} is the dynamic viscosity of oil at hotspot location, cP
$\mu_{ohs,r}$ is the dynamic viscosity of oil at hotspot location at rated load, cP

For the ODAF cooling mode, no viscosity correction is used since the oil is pumped and the heat lost at the hotspot location is given by:

$$\dot{Q}_{lost,whs} = \left[\frac{\theta_{whs} - \theta_{ohs}}{\theta_{whs,r} - \theta_{ohs,r}}\right] (P_{whs,r} + P_{ehs,r}) \tag{31}$$

where

$P_{ehs,r}$ is the eddy loss at rated load and rated winding hotspot temperature, W
$P_{whs,r}$ is the winding I2R loss at rated load and rated hotspot temperature, W
$\dot{Q}_{lost,whs}$ is the heat dissipation rate by winding at hotspot location, W
θ_{whs} is the winding hotspot temperature, °C

$\theta_{whs,r}$ is the winding hotspot temperature at rated load °C
θ_{ohs} is the temperature of oil adjacent to winding hotspot, °C
$\theta_{ohs,r}$ is the temperature of oil adjacent to winding hotspot at rated load, °C

Finally, the winding hotspot temperature is found by solving Equation (18)

$$m_w c_p \frac{d\theta_{whs}}{dt} = K^2 \left[P_{whs,r} K_{whs} + \frac{P_{ehs,r}}{K_{whs}}\right] - \left[\frac{\theta_{whs}-\theta_{ohs}}{\theta_{whs,r}-\theta_{ohs,r}}\right]^{5/4} \left[\frac{\mu_{ohs,r}}{\mu_{ohs}}\right]^{1/4} (P_{whs,r} + P_{ehs,r}) \tag{32}$$

where

m_w is the winding mass, kg
$c_{p,w}$ is specific heat
$\dot{Q}_{gen,whs}$ is the rate of heat generation at hotspot location, W
$\dot{Q}_{lost,whs}$ is the rate of heat dissipation at hotspot location, W
θ_{whs} is the winding hotspot temperature, °C
$\theta_{whs,r}$ is the winding hotspot temperature at rated load °C
θ_{ohs} is the temperature of oil adjacent to winding hotspot, °C
$\theta_{ohs,r}$ is the temperature of oil adjacent to winding hotspot at rated load, °C
μ_{ohs} is the dynamic viscosity of oil at hotspot location, cP
$\mu_{ohs,r}$ is the dynamic viscosity of oil at hotspot location at rated load, cP
K is the ratio of load to rated load, per unit
$P_{whs,r}$ is the winding I^2R loss at rated load and rated hotspot temperature, W
$P_{ehs,r}$ is the eddy loss at rated load and rated winding hotspot temperature, W
K_{whs} is the temperature correction for losses at hotspot location, per unit

or for the ODAF cooling mode the winding hotspot temperature is found by solving Equation (31)

$$m_w c_p \frac{d\theta_{whs}}{dt} = K^2 \left[P_{whs,r} K_{whs} + \frac{P_{ehs,r}}{K_{whs}}\right] - \left[\frac{\theta_{whs}-\theta_{ohs}}{\theta_{whs,r}-\theta_{ohs,r}}\right] (P_{whs,r} + P_{ehs,r}) \tag{33}$$

where

m_w is the winding mass, kg
$c_{p,w}$ is specific heat
$\dot{Q}_{gen,whs}$ is the rate of heat generation at hotspot location, W
$\dot{Q}_{lost,whs}$ is the rate of heat dissipation at hotspot location, W
θ_{whs} is the winding hotspot temperature, °C
$\theta_{whs,r}$ is the winding hotspot temperature at rated load °C
θ_{ohs} is the temperature of oil adjacent to winding hotspot, °C
$\theta_{ohs,r}$ is the temperature of oil adjacent to winding hotspot at rated load, °C
K is the ratio of load to rated load, per unit
$P_{whs,r}$ is the winding I^2R loss at rated load and rated hotspot temperature, W
$P_{ehs,r}$ is the eddy loss at rated load and rated winding hotspot temperature, W
K_{whs} is the temperature correction for losses at hotspot location, per unit

7.2.6 Determination of average oil temperature

The heat lost by the windings to the duct oil and the heat generated by the core and stray losses is absorbed by the bulk oil in the main tank and radiators, and is lost to the ambient air. The heat generated by the core varies slightly with temperature; however, it is assumed constant for the analysis. However, overexcitation during the load cycle increases core loss.

The average oil temperature is found by solving differential Equation (34).

$$\sum m \cdot c_p \frac{d\theta_{ao}}{dt} = \dot{Q}_{lost,w} + \dot{Q}_c + \dot{Q}_s - \dot{Q}_{lost,o} \tag{34}$$

where

$\dot{Q}_{lost,o}$ is the rate of heat dissipated for oil, W
$\dot{Q}_{lost,w}$ is the rate of heat dissipated from winding, W
$\dot{Q}_c$ is the rate of heat generation by core, W
$\dot{Q}_s$ is the rate of heat generated by stray losses, W
$\Sigma m \cdot c_p$ is the total mass times specific heat of oil, tank, and core, W/°C
θ_{ao} is the average oil temperature in tank and radiator, °C

The heat lost by the windings to oil is given by Equation (16) and Equation (17).

The heat generated by the core is given by Equation (35), Equation (36), and Equation (37) as follows:

For normal excitation:

$$\dot{Q}_c = P_{c,r} \tag{35}$$

where

$P_{c,r}$ is the core (no-load) loss, W
$\dot{Q}_c$ is the heat generation rate by core, W

For overexcitation:

$$\dot{Q}_c = P_{c,oe} \tag{36}$$

where

$P_{c,oe}$ is the core loss when overexcitation occurs, W
$\dot{Q}_c$ is the heat generation rate by core, W

The heat generated by the stray loss is given by

$$\dot{Q}_s = \left[\frac{K^2 P_{s,r}}{K_w}\right] \tag{37}$$

where

K is the ratio of load to rated load, per unit
K_w is the temperature correction for losses of winding, per unit
$P_{s,r}$ is the stray losses at rated load, W
$\dot{Q}_s$ is the heat generation rate due to stray losses, W

The temperature correction, K_w for stray loss is given by Equation (15) and assumes that the temperature of the structural parts is the same as the average winding temperature.

The total losses at rated load is given by Equation (38):

$$P_{tot,r} = P_{w,r} + P_{e,r} + P_{s,r} + P_c \tag{38}$$

where

P_c is the core (no-load) loss, W
$P_{e,r}$ is the eddy loss of windings at rated load, W
$P_{s,r}$ is the stray losses at rated load, W
$P_{tot,r}$ is the total losses at rated load, W
$P_{w,r}$ is the winding I^2R loss at rated load, W

The heat dissipation rate for the oil is given by Equation (39) as follows:

$$\dot{Q}_{lost,o} = \left[\frac{\theta_{ao}-\theta_a}{\theta_{ao,r}-\theta_{a,r}}\right]^{1/y} P_{tot,r} \tag{39}$$

where

$P_{tot,r}$ is the total losses at rated load, W
$\dot{Q}_{lost,o}$ is the heat dissipation rate from oil to air, W
θ_a is the ambient temperature, °C
$\theta_{a,r}$ is the rated ambient at kVA base for load cycle, °C
θ_{ao} is the average oil temperature in tank and radiator, °C
$\theta_{ao,r}$ is the average oil temperature in tank and radiator at the rated load, °C
y is the exponent of average oil rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF

To determine the core weight, it is necessary to subtract the weight of the windings used in Equation (40) from the total core and coil weight given on the outline drawing supplied by the manufacturer.

$$m_w = \frac{m_w c_{pw}}{c_{pw}} \tag{40}$$

where

c_{pw} is the specific heat of winding material, W/kg K
m_w is the mass of windings, kg

$$m_{core} = m_{cc} - m_w \tag{41}$$

where

m_{cc} is the core and coil (untanking) weight, kg
m_{core} is the mass of core, kg
m_w is the mass of windings, kg

$$\sum m \cdot c_p = m_{tank} c_{p,tank} + m_{core} c_{p,core} + m_{oil} c_{p,oil} \tag{42}$$

where

$c_{p,core}$ is the specific heat of the core, W/(kgK)
$c_{p,oil}$ is the specific heat of oil, W/(kgK)
$c_{p,tank}$ is the specific heat of the tank, W/(kgK)
m_{core} is the mass of core, kg
m_{oil} is the mass of oil, kg
m_{tank} is the mass of tank, kg
$\sum m \cdot c_p$ is the total mass times specific heat of oil, tank, and core, W/°C

The heat lost by the windings to oil is given by Equation (16) and Equation (17).

The average oil temperature is found by solving equation (43).

$$\sum m \cdot c_p \frac{d\theta_{ao}}{dt} = \left[\frac{\theta_{aw}-\theta_{ado}}{\theta_{aw,r}-\theta_{ado,r}}\right]^{1.25} \left[\frac{\mu_r}{\mu}\right]^{0.25} (P_{w,r} + P_{e,r}) + P_{c,oe} + \left[\frac{K^2 P_{s,r}}{K_w}\right] - \left[\frac{\theta_{ao}-\theta_a}{\theta_{ao,r}-\theta_{a,r}}\right]^{1/y} P_{tot,r} \qquad (43)$$

where

$\Sigma m \cdot c_p$ is the total mass times specific heat of oil, tank, and core, W/°C
θ_{ao} is the average oil temperature in tank and radiator, °C
$\theta_{ao,r}$ is the average oil temperature in tank and radiator at the rated load, °C
θ_a is the ambient temperature, °C
$\theta_{a,r}$ is the rated ambient at kVA base for load cycle, °C
y is the exponent of average oil rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF
$P_{e,r}$ is the eddy loss of windings at rated load, W
$P_{s,r}$ is the stray losses at rated load, W
$P_{tot,r}$ is the total losses at rated load, W
$P_{w,r}$ is the winding I^2R loss at rated load, W
K is the ratio of load to rated load, per unit
K_w is the temperature correction for losses of winding, per unit
μ is the viscosity of the oil for the temperature defined in Table [viscosity table] [kg/(s·m)] [Pa·s]
μ_r is the viscosity of the oil for the average winding temperature rise at rated load, cP [kg/(s·m)] [Pa·s]

7.2.7 Determination of top and bottom oil temperatures

The top and bottom oil temperatures are determined by an equation similar to the equation for duct oil rise.

$$\Delta\theta_{to/bo} = (\theta_{to} - \theta_{bo}) = \left[\frac{\dot{Q}_{lost,o}}{P_{tot,r}}\right]^{z} (\theta_{to,r} - \theta_{bo,r}) \qquad (44)$$

where

z is the exponent for top to bottom oil temperature difference and is 0.5 for ONAN and ONAF; 1.0 for OFAF and ODAF
$P_{tot,r}$ is the total losses at rated load, W
$\dot{Q}_{lost,o}$ is the heat dissipation rate for oil, W
$\Delta\theta_{to/bo}$ is the temperature rise of oil at top of radiator over bottom oil, °C
θ_{bo} is the bottom oil temperature, °C
$\theta_{bo,r}$ is the bottom oil temperature at rated load, °C
θ_{to} is the top oil temperature in tank and radiator, °C
$\theta_{to,r}$ is the top oil temperature in tank and radiator at rated load, °C

The heat lost by the oil, $Q_{lost,o}$ is given by Equation (38). The top and bottom oil temperatures then are determined as follows:

$$\theta_{bo} = \theta_{ao} - \frac{\Delta\theta_{to/bo}}{2} \tag{45}$$

$$\theta_{to} = \theta_{ao} + \frac{\Delta\theta_{to/bo}}{2} \tag{46}$$

where

θ_{ao} is the average oil temperature in tank and radiator, °C
θ_{bo} is the bottom oil temperature, °C
θ_{to} is the top oil temperature in tank and radiator, °C
$\Delta\theta_{to/bo}$ is the temperature rise of oil at top of radiator over bottom oil, °C

7.2.8 Alternative method for determination of top oil and hotspot temperature

An alternative method for the determination of top oil temperature is based on the modified equations of Clause 7 [B9]. Informative Annex J covers historical background and explains the need for the modification of previous thermal model. In this approach, the top oil temperature is found by solving first order differential Equation (47).

$$\tau_{to}\frac{d\theta_{to}}{dt} = \Delta\theta_{to/a,r}\left[\frac{1+K^2R}{1+R}\right]^n - (\theta_{to} - \theta_a) \tag{47}$$

where

θ_{to} is the top oil temperature in tank and radiator, °C
R is the ratio of load losses to no load losses, p.u.
θ_a is the ambient temperature
K is the load factor, p.u.
$\Delta\theta_{to/a,r}$ is the top oil over ambient temperature rise at rated load, K
τ_{to} is the time constant for top oil, min
n is the oil exponent (see Table 3)

The hottest-spot temperature can be found by solving similar differential Equation (48).

$$\tau_w\frac{d\theta_{whs}}{dt} = \Delta\theta_{whs/to,r}K^{2m} - (\theta_{whs} - \theta_{to}) \tag{48}$$

where

θ_{whs} is the winding hotspot temperature, °C
θ_{to} is the top oil temperature in tank and radiator, °C
K is the load factor, p.u.
$\Delta\theta_{whs/to,r}$ is the winding over top oil temperature rise at rated load, K
τ_w is the winding time constant, min
m is the winding exponent (see Table 3)

Care must be exercised when applying the alternative set of equations as these are subject to many above mentioned limitations (see clause "Simplified thermal model").

Nevertheless, the computer code of the alternative model for calculating the top oil and hotspot temperatures is available within an open-source code project, explained in Annex G.

The alternative model is a special case of the Pierce model, also known as the former Annex G model [B22], [B23]. A mathematical proof that the model [B24], [B25] is a special case of the Pierce model is provided in Annex K.

7.2.9 Stability requirements

The stability of the solution of this system of differential algebraic equations is dependent on the time interval between successive measurements. This time interval must be at least two times smaller than the winding time constant, which can be between 5 min and 15 min. A time interval of 1 min is desirable. If the input data is sampled at the rate higher than 1 min, then linear interpolation is used to comply with the stability requirements.

7.2.10 Oil viscosity and specific heats of materials

Oil viscosity is highly temperature dependent. The oil viscosity at any temperature is given by an equation of the form:

$$\mu = D e^{G/(\theta+273)} \tag{49}$$

where

- D is a constant (Table 2)
- G is a constant (Table 2)
- θ is the temperature of oil to use for viscosity, °C
- μ is the viscosity of oil, cP

The temperatures used to calculate the viscosity are given in Table 4. Values of the constants D and G for three transformer oils were derived from property data given in ASTM D3487, ASTM D4652, and ASTM D5222. The values of these constants are given in Table 5. The specific heats of materials vary only slightly with temperature. As a result, a constant value may be used. Specific heats of materials are given in Table 2.

Table 4—Temperatures for calculating viscosity

Equation number	Viscosity term	Temperature for viscosity calculation
4A	$\mu_{aw,r}$	$(\theta_{aw,r} + \theta_{dao,r})/2$
4A	μ_{aw}	$(\theta_{aw} + \theta_{dao})/2$
14A	$\mu_{whs,r}$	$(\theta_{whs,r} + \theta_{ohs,r})/2$
14A	μ_{whs}	$(\theta_{whs} + \theta_{ohs})/2$

Table 5—Specific heat and constants for viscosity calculation

Material	Cp[a]	D	G
Oil	13.92	.0013573	2797.3
Silicone	11.49	.12127	1782.3
HTHC	14.55	.00007343	4434.7
Tank(steel)	3.51	N/A	N/A
Core(steel)	3.51	N/A	N/A
Copper	2.91	N/A	N/A
Aluminum	6.80	N/A	N/A

[a]W./kg °C

7.2.11 Summary of exponents

The values of the exponents used in the temperature calculations are summarized in Table 6.

The computer program allows changing the *y* exponent for cases for which test data is available.

Table 6—Summary of exponents

Exponent	Used for	Cooling mode			
		ONAN	ONAF	OFAF	ODAF
x	Duct oil rise	0.5	0.5	0.5	1.0
y	Average oil rise	0.8	0.9	0.9	1.0
z	Top to bottom oil rise Radiator	0.5	0.5	1.0	1.0
n	Oil exponent in (26)	0.8	0.9	0.9	1.0
m	Winding exponent in (27)	0.8	0.8	0.8	1.0

7.2.12 Adjustment of rated test data for a different tap position

If it is desired to adjust the test data for operation on a no-load tap position, other than that reported on the test report, Equation (50) through Equation (52) may be used as follows:

7.2.13 Adjustment of top- and bottom-oil rise over ambient

$$\Delta\theta_{ao,r} = \frac{\Delta\theta_{to,r} + \Delta\theta_{bo,r}}{2} \tag{50}$$

where

$\Delta\theta_{ao/r}$ is the average oil rise over ambient at rated load, °C
$\Delta\theta_{bo,r}$ is the bottom oil rise over ambient at rated load, °C
$\Delta\theta_{to,r}$ is the top oil rise over ambient at rated load, °C

$$\Delta\theta'_{to,r} = \Delta\theta_{ao,r}\left[\frac{P'_{tot,r}}{P_{tot,r}}\right]^{y} + \left[\frac{\Delta\theta_{to,r}-\Delta\theta_{bo,r}}{2}\right]\left[\frac{P'_{tot,r}}{P_{tot,r}}\right]^{z} \quad (51)$$

where

- $P_{tpt,r}$ is the total losses at rated load, W
- $P'_{tot,r}$ is the total losses on a different tap, W
- y is the exponent of average oil rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF
- z is the exponent for top to bottom oil temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF
- $\Delta\theta_{ao,r}$ is the average oil rise over ambient at rated load, °C
- $\Delta\theta_{bo,r}$ is the bottom oil rise over ambient at rated load, °C
- $\Delta\theta_{to,r}$ is the top oil rise over ambient at rated load, °C
- $\Delta\theta'_{to,r}$ is the top oil rise over ambient at rated load on a different tap, °C

$$\Delta\theta'_{bo,r} = \Delta\theta_{ao,r}\left[\frac{P'_{tot,r}}{P_{tot,r}}\right]^{y} - \left[\frac{\Delta\theta_{to,r}-\Delta\theta_{bo,r}}{2}\right]\left[\frac{P'_{tot,r}}{P_{tot,r}}\right]^{z} \quad (52)$$

where

- $P_{tot,r}$ is the total losses at rated load, W
- $P'_{tot,r}$ is the total losses on a different tap, W
- y is the exponent of average oil rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF
- z is the exponent for top to bottom oil temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF
- $\Delta\theta_{ao,r}$ is the average oil rise over ambient at rated load, °C
- $\Delta\theta_{bo,r}$ is the bottom oil rise over ambient at rated load, °C
- $\Delta\theta'_{bo,r}$ is the bottom oil rise over ambient at rated load on a different tap, °C
- $\Delta\theta_{to,r}$ is the top oil rise over ambient at rated load, °C

7.2.14 Adjustment of average winding rise over ambient

For ONAN, ONAF, and ODAF:

$$\Delta\theta_{tdo/bo,r} = \Delta\theta_{to,r} - \Delta\theta_{bo,r} \quad (53)$$

where

- $\Delta\theta_{bo,r}$ is the bottom oil rise over ambient at rated load, °C
- $\Delta\theta_{tdo/bo,r}$ is the temperature rise of oil at top of duct over bottom oil at rated load, °C
- $\Delta\theta_{to,r}$ is the top oil rise over ambient at rated load, °C

For OFAF:

$$\Delta\theta_{tdo/bo,r} = \Delta\theta_{w/a,r} - \Delta\theta_{bo,r} \quad (54)$$

where

- $\Delta\theta_{bo,r}$ is the bottom oil rise over ambient at rated load, °C
- $\Delta\theta_{do/bo,r}$ is the temperature rise of oil at top of duct over bottom oil at rated load, °C
- $\Delta\theta_{w/a,r}$ is the tested or rated average winding rise over ambient, °C

then

$$\Delta\theta'_{tdo/bo,r} = \Delta\theta_{tdo/bo,r} \left[\frac{I'_r}{I_r}\right]^{2x} \tag{55}$$

where

I_r	is the rated current at rated load, A
I'_r	is the rated current at rated load at a different tap position, A
x	is the exponent for duct oil rise over bottom oil, 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF
$\Delta\theta_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load, °C
$\Delta\theta'_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load at a different tap position, °C

For ONAN, ONAF, and OFAF:

$$\Delta\theta'_{aw/a,r} = \left[\Delta\theta_{whs/a,r} - \Delta\theta_{bo,r} - \frac{\Delta\theta_{tdo/bo,r}}{2}\right]\left[\frac{I'_r}{I_r}\right]^{1.6} + \Delta\theta'_{bo,r} + \frac{\Delta\theta'_{tdo/bo,r}}{2} \tag{56}$$

where

I_r	is the rated current at rated load, A
I'_r	is the rated current at rated load at a different tap position, A
$\Delta\theta_{bo,r}$	is the bottom oil rise over ambient at rated load, °C
$\Delta\theta'_{bo,r}$	is the bottom oil rise over ambient at rated load at a different tap position, °C
$\Delta\theta_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load, °C
$\Delta\theta'_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load at a different tap position, °C
$\Delta\theta_{aw/a,r}$	is the tested or rated average winding rise over ambient, °C
$\Delta\theta'_{aw/a,r}$	is the tested or rated average winding rise over ambient at a different tap position, °C

For ODAF:

$$\Delta\theta'_{aw,r} = \left[\Delta\theta_{aw,r} - \Delta\theta_{bo,r} - \frac{\Delta\theta_{do/bo,r}}{2}\right]\left[\frac{I'_r}{I_r}\right]^{2} + \Delta\theta'_{bo,r} + \frac{\Delta\theta'_{do/bo,r}}{2} \tag{57}$$

where

I_r	is the rated current at rated load, A
I'_r	is the rated current at rated load at a different tap position, A
$\Delta\theta_{bo,r}$	is the bottom oil rise over ambient at rated load, °C
$\Delta\theta'_{bo,r}$	is the bottom oil rise over ambient at rated load at a different tap position, °C
$\Delta\theta_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load, °C
$\Delta\theta'_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load at a different tap position, °C
$\Delta\theta_{aw/a,r}$	is the tested or rated average winding rise over ambient, °C
$\Delta\theta'_{aw/a,r}$	is the tested or rated average winding rise over ambient at a different tap position, °C

Adjustment of hotspot rise over ambient For ONAN, ONAF, and OFAF:

$$\Delta\theta'_{whs/a,r} = \left[\Delta\theta_{whs/a,r} - \Delta\theta_{bo,r} - \Delta\theta_{tdo/bo,r}\right]\left[\frac{I'_r}{I_r}\right]^{1.6} + \Delta\theta'_{bo,r} + \Delta\theta'_{tdo/bo,r} \quad (58)$$

where

I_r	is the rated current at rated load, A
I'_r	is the rated current at rated load at a different tap position, A
$\Delta\theta_{bo,r}$	is the bottom oil rise over ambient at rated load, °C
$\Delta\theta'_{bo,r}$	is the bottom oil rise over ambient at rated load at a different tap position, °C
$\Delta\theta_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load, °C
$\Delta\theta'_{tdo/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load at a different tap position, °C
$\Delta\theta_{whs/a,r}$	is the winding hotspot rise over ambient at rated load, °C
$\Delta\theta'_{whs/a,r}$	is the winding hotspot rise over ambient at rated load at a different tap position, °C

For ODAF:

$$\Delta\theta'_{whs/a,r} = \left[\Delta\theta_{whs/a,r} - \Delta\theta_{bo,r} - \Delta\theta_{do/bo,r}\right]\left[\frac{I'_r}{I_r}\right]^{2} + \Delta\theta'_{bo,r} + \Delta\theta'_{do/bo,r} \quad (59)$$

where

I_r	is the rated current at rated load
I'_r	is the rated current at rated load at a different tap position
$\Delta\theta_{bo,r}$	is the bottom oil rise over ambient at rated load, °C
$\Delta\theta'_{bo,r}$	is the bottom oil rise over ambient at rated load at a different tap position, °C
$\Delta\theta_{do/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load, °C
$\Delta\theta'_{do/bo,r}$	is the temperature rise of oil at top of duct over bottom oil at rated load at a different tap position, °C
$\Delta\theta_{whs/a,r}$	is the winding hotspot rise over ambient at rated load, °C
$\Delta\theta'_{whs/a,r}$	is the winding hotspot rise over ambient at rated load at a different tap position, °C

7.2.15 Entering load daily data and ambient temperatures

Values for the per-unit load and ambient temperature are obtained from an actual data file in comma delimited (csv) format. All other data is entered in interactive mode after executing the open-source python code.

Input parameters for the Pierce and alternative thermal models are summarized in Table 7.

As mentioned above, the temperature rise test is performed (and calculations of temperature rises made when a test is not performed) on the maximum loss tap position. This data results in conservative predictions of loading capability when the transformer is operated on other than the maximum loss tap. To achieve more accurate predictions of the capability of a transformer based on the actual loading cycle and tap connections, several adjustments may be made of the data presented in the test report before the data is used as input to loading calculations. These adjustments are provided in the following:

- Load cycle in kVA on the actual combination of tap connections.
- Use the measured or calculated load losses for that tap connection.
- Correct the temperature rise test data for the lower losses or different rated current.
- Determine if the hottest spot winding gradient changes with changes in the tap connections.

Calculating the effect of load tap changer operation into the loading predictions is an extremely complicated and debated subject. The effect may vary with manufacturer or potentially even model to model. For some designs, the effect of load tap changer operation may have a negligible effect on temperature rises of the transformer windings.

Table 7—Input parameters for the Pierce and Alternative thermal models

Model parameters	Pierce's model	Montsinger-Cooney model
Power basis for per unit loss calculation	✓	
Temperature basis at which loss was measured	✓	
Winding DC Losses	✓	
Winding Eddy Losses	✓	
Stray Losses	✓	
Total winding losses		✓
Core Losses	✓	✓
Cooling mode	✓	✓
Nameplate apparent power rating	✓	✓
Guaranteed average winding rise	✓	✓
Average winding rise at rated load	✓	✓
Hottest-spot rise at rated load	✓	✓
Top oil rise at rated load	✓	✓
Bottom oil rise at rated load	✓	
Rated Ambient Temperature	✓	✓
P.U. eddy loss at hottest-spot location	✓	
Winding time constant	✓	✓
Top oil time const		✓
P.U. winding height to hottest spot location	✓	
Weight of core & coils	✓	
Weight of tank & fittings	✓	
Oil volume	✓	
Load to no-load losses ratio		✓
Duct oil rise exponent (x)	✓	
Average oil rise exponent (y)	✓	
Exponent for top to bottom oil temperature difference (z)	✓	

8. Loading of distribution transformers and step-voltage regulators

8.1 Estimated life

8.1.1 General

The estimated life of distribution transformers and voltage regulators at any operating temperature is not accurately known. The information available regarding the loss of insulation life at elevated temperatures is conservative and the best that can be produced from present knowledge of the subject. The effects of temperature on insulation life are being investigated continuously, and new data may affect future revisions of this guide. The word conservative, as used above, is used in the sense that the expected loss of insulation life for a single overload cycle will not be greater than the amount stated.

Since the cumulative effects of temperature and time in causing deterioration of insulation are not thoroughly established. It is not possible to predict, with any great degree of accuracy, the length of life of a transformer, even under constant or closely controlled conditions, much less under widely varying service conditions. Deterioration of insulation is generally characterized by a reduction in mechanical strength and in dielectric strength, but these characteristics may not necessarily be directly related. In some cases, insulation in a charred condition will have sufficient insulating qualities to withstand normal operating electrical and mechanical stresses. A transformer or voltage regulator having insulation in this condition may continue in service for many months or even years, if undisturbed. Alternatively, any unusual movement of the conductors, such as may be caused by expansion of the conductors due to increased heating or to large electromagnetic forces resulting from short circuit, may disturb the mechanically weak insulation such that a turn-to-turn, or a layer-to-layer failure will result.

The recommendations of this guide are based upon the estimated life curve of Figure 1, which relates to the insulation system. However, this guide, does not account for such factors as deterioration of gaskets, rusting of tanks, etc., that are induced by exposure to the elements of the weather in normal operations.

8.1.2 Normal estimated life

The basic loading of a distribution transformer or voltage regulator for a normal estimated life is continuous loading at rated output when operated under usual service conditions, as indicated in 4.1 of IEEE Std C57.12.00-2010 and 4.1 of IEEE Std C57.15-2009. It is assumed that operation under these conditions is equivalent to operation in a constant 30 °C ambient temperature. The hottest spot conductor temperature is the principal factor in determining life due to loading. The weakest spot of the solid insulation is typically at the transformer hottest spot due to having the most thermal degradation. Direct temperature measurement of the hottest spot may not be practical on many commercial designs. The indicated hottest spot temperatures have, therefore, been obtained from tests made in the laboratory and mathematical models. The hottest spot temperature at rated load is the sum of the average winding temperature and a hottest spot allowance, usually 15 °C. Normal estimated life will result from operating continuously with hottest spot conductor temperature of 110 °C or an equivalent daily transient cycle. For mineral oil-immersed transformers and voltage regulators operating continuously under the foregoing conditions, this temperature has been limited to a maximum of 110 °C. Normal estimated life of transformer and voltage regulator insulation using different criteria is given in 1. Distribution and power transformer model tests indicate that the normal estimated life at a continuous hottest spot temperature of 110 °C is 20.55 years (180,000 hours).

8.2 Limitations

8.2.1 General

When loading distribution transformers and voltage regulators above the nameplate rating, other limitations may be encountered. Among these limitations are oil expansion, pressure in sealed units, and the thermal capability of bushings; leads, tap changers, or associated equipment such as cables, reactors, circuit breakers, fuses, disconnecting switches, and current transformers. Any of these items may limit the loading to less than the capability of the winding insulation. Manufacturers should, therefore, be consulted before loading transformers or voltage regulators above the nameplate rating. Operation at hottest spot temperatures above 140 °C may cause gassing in the solid insulation and the oil. Gassing may produce a potential risk to the dielectric strength integrity of the transformer or voltage regulator and this risk should be considered when the guide is applied.

Distribution transformers are sometimes installed in subsurface manholes and vaults of minimum size, with natural ventilation through roof gratings. This type of installation results in a higher ambient temperature than the outdoor air. The amount of temperature increase depends on the design of the manholes and vaults, net opening area of the roof gratings, and the adjacent subsurface structures. Therefore, the increase in effective ambient temperature for expected transformer losses must be determined before loading limitations can be estimated.

The separate heating effects of loading a distribution transformer or voltage regulator, and of solar radiation, may each result in an enclosure surface temperature high enough to present a hazard to personnel who might come in contact with the enclosure surface where unlimited access to the transformer or voltage regulator exists (such as certain pad-mounted units).

8.2.2 Limitations for loading distribution transformers above nameplate rating

Suggested limits of temperature or load for loading distribution transformers above the nameplate rating are given in Table 8 (Note: the above discussion on hottest spot temperatures in excess of 140 °C).

Table 8—Suggested limits of temperature or load for loading above nameplate distribution transformers with 65 °C rise

Top-oil temperature	120 °C
Hottest spot conductor temperature	200 °C[a]
Short-time loading (1/2 h or less)	300%

[a] See discussion on hottest spot temperatures in excess of 140 °C in 8.2.1.

8.3 Types of loading

8.3.1 Loading for normal estimated life under specific conditions

Distribution transformers and voltage regulators may be operated above 110 °C average continuous hottest spot temperature for short periods, provided they are operated for much longer periods at temperatures below 110 °C. This is due to thermal aging being a cumulative process. This permits loads above the rating to be safely carried under specified conditions without encroaching upon the normal estimated life of the transformer and voltage regulator. When the ambient temperature is below the 30 °C ambient used to establish the rating of the transformer or voltage regulator, or when the temperature rise of the transformer at the nameplate rated load, as determined by testing, are less than the normal limiting values, some additional load beyond nameplate rating is possible within normal life expectations.

8.3.2 Loading by top-oil temperature

Top-oil temperature alone should not be used as a guide for loading transformers and voltage regulators. The hottest spot winding rise over top-oil temperature at full load should be determined from the factory tests corrected for the actual load carried by using Equation (37). This hottest spot rise over top-oil, subtracted from 110 °C, will give the maximum permissible top-oil temperature for normal estimated life. It should be recognized that, due to the thermal lag in the oil temperature rise, time is required for a transformer or voltage regulator to reach a stable temperature for any change in load. Therefore, higher peak loads may be carried for a short duration. If the transformer or voltage regulator characteristics are not accurately known, maximum top-oil temperatures derived from Figure 1 may be used as an approximate guide. Figure 5 is based on a difference between hottest spot temperature and top-oil temperature of 25 °C at rated load.

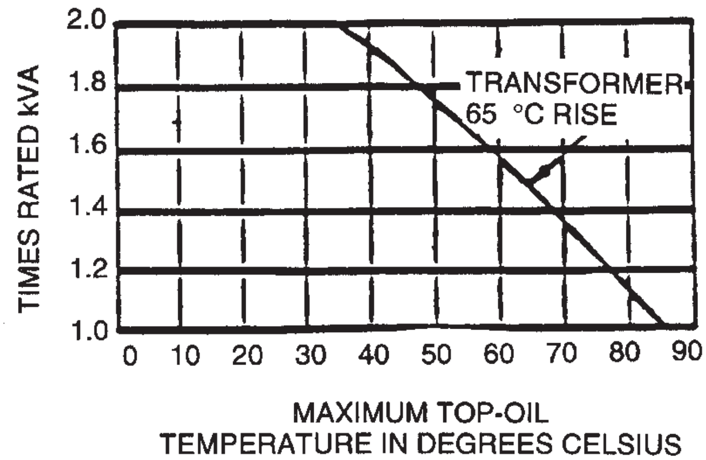


Figure 5— Approximate continuous loading for normal life expectancy based on maximum top-oil temperature

8.3.3 Continuous loading based on average winding test temperature rise

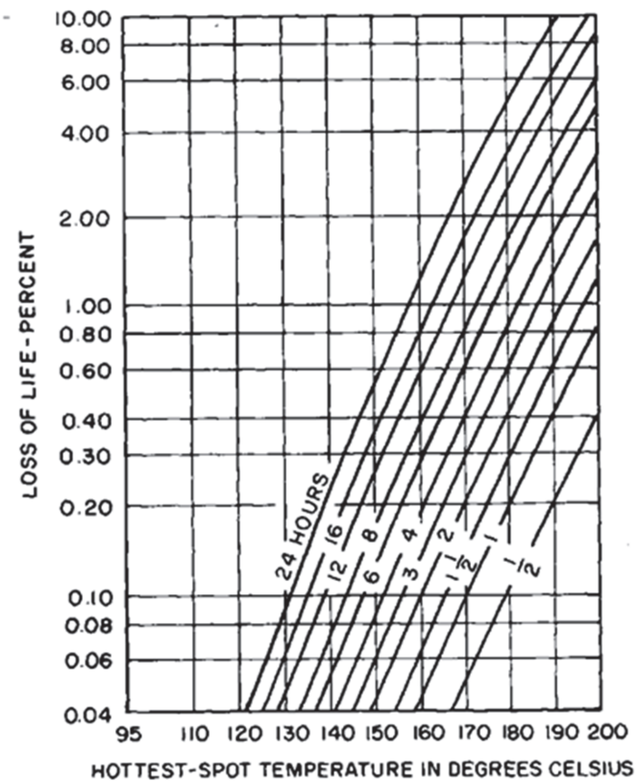
For each degree Celsius, in excess of 5 °C that the average winding test temperature rise is below 65 °C, the transformer or voltage regulator load may be increased above rated kVA by 1.0%. The 5 °C margin is taken to provide a tolerance in the measurement of temperature rise. The load value, thus obtained, is the kVA load, which the transformer or voltage regulator can carry at 65 °C rise. Since this may indicate a load capability beyond that contemplated by the designer, the limitations given in 8.2 should be checked before taking full advantage of this increase.

The above is not applicable to all distribution transformers and voltage regulators. Some transformers are designed to have the difference between the hottest spot and average winding temperatures greater than the 15 °C allowance. This will result in an average winding temperature rise of less than 65 °C, while the hottest spot winding rise may be at the 80 °C limiting value. This condition may exist in transformers and voltage regulators with large differences between top and bottom-oil temperatures. The manufacturer should be consulted for information on the hottest spot allowance used for these designs.

8.3.4 Short-time loading with moderate sacrifice of estimated life (operation above 110 °C hottest- spot temperature)

For any given period of time, the aging effect of one overload cycle or the cumulative aging effect of a number of overload cycles is greater than the aging effect of continuous operation at rated load, the insulation deteriorates at an accelerated rate. The rate of deterioration is a function of time and temperature and is commonly expressed as a percentage loss of life per incident. A chart and table showing the relative loss of life for various combinations of time and temperature are given in Figure 6 for 65 °C rise transformers and voltage regulators.

While the insulation aging rate information is conservative and helpful in estimating the relative loss of life due to loads above nameplate rating under various conditions, this information is not intended to furnish the sole basis for calculating the normal estimated life of transformer and voltage regulator insulation. The uncertainty of service conditions and the wide range of ratings covered should be considered in determining a loading schedule. Some variables to consider are wide differences in ambient temperature between localities; differences in elevation; restricted air circulation caused by buildings, fire walls, etc.; previous emergency loading history that may not be known to the operator; and variations in design characteristics. As a guide, many users consider an average loss of life of 4% per day in any one emergency operation to be reasonable.



Time (h)	0.05	0.10	0.25	%loss of life[a] 0.50	1.00	2.00	4.00
1/2	171	180	193	204[b]			
1	161	171	183	193	204[b]		
2	153	161	174	183	193	204[b]	
4	144	153	164	174	183	193	204[b]
8	136	144	155	164	174	183	193
16	128	136	147	155	164	174	183
24	124	131	142	150	159	168	178

[a] Calculated for one occurrence on the assumption that the hottest-spot temperature remains constant for the specified time duration. For loss of life determinations in which the time-temperature response of the transformer is taken into account, refer to clauses 5 and 7.
[b] Maximum permissible value is 200 °C; the underlined values permit interpolation.

Figure 6— Loss of estimated life (based on a normal life of 180,000 hours)

8.4 Loading specific to voltage regulators

8.4.1 General

Most voltage regulators are 55 °C rise products, of sealed construction, and use thermally upgraded paper insulation. Some voltage regulator nameplates show both 55 °C and 65 °C ratings with a 1.12 factor in the kVA rating for the higher rise units. The tap changer is integral to the regulator and usually is the critical factor in establishing the loading limits. Contact life is significantly affected by loading practices.

Regulators are thermally designed, and nameplate rated for operation continuously at the extreme raise and lower tap positions. According to IEEE Std C57.15, regulators may be continuously loaded, in discretely defined increments, above that rating if the tap position range is restricted

Most regulators are designed for application at multiple nominal system voltages but one specific load current rating.

8.4.2 Restricted regulation

Many step-voltage regulators are adjusted to step voltages up or down, less than their maximum design amount. When step-voltage regulators that do not include a series transformer have restricted voltage ranges, less series winding is in the circuit and the load current in the shunt winding is less than at the full range of regulation.

The manufacturer should be consulted for his recommendation concerning additional load current that can be carried when the voltage range is restricted. Limitations indicated in 8.2.1 may affect the maximum loads indicated in Table 9, which gives an approximate guide for restricted range application. Designs that do not include a series transformer, the loads given in Table 9 will give a normal estimated life. However, the maximum continuous load current should be limited to 668 A

Table 9—Loading with reduced regulation (based on ± 10 % range)

Limiting regulating range %	Load (% of rated load current)
± 10	100
± 8 ¾	110
± 7 ½	120
± 6 ¾	135
± 5	160

8.4.3 Loading with reduced voltages

Step-voltage regulators are sometimes applied to systems operating at voltages below their nameplate rating. Under these conditions, the percent regulation remains the same.

The load current rating does not change; however, the kVA rating and the kVA being controlled are both reduced in proportion to the voltage being used for most voltage ratings. The only exception is the 7620 volt rating. This voltage rated regulator will commonly be applied at the lower voltage of 7200 volts.

8.4.4 Limitations for loading voltage regulators above nameplate rating

Suggested limits of temperature and load for loading above the nameplate rating are given in Table 10.

Table 10 —Suggested limits of temperature and load for loading above nameplate voltage regulators with 55 °C or 65 °C Rise

Description	**55 °C**	**65 °C**
Top Oil Temperature	100 °C	110 °C
Hottest Spot Conductor Temperature	180 °C	180 °C
Short Time Loading (1/2 hour or less)	200%	200%

9. Loading of Power Transformers

9.1 Types of loading and their interrelationship

Power transformer estimated life at various operating temperatures is not accurately known, but the information given regarding loss of insulation life at elevated temperature is the best that can be produced from present knowledge of the subject. Loads in excess of nameplate rating may subject insulation to temperatures higher than the basis of rating definition. To provide guidance on risk associated with higher operating temperature, four different loading conditions beyond nameplate have been developed as examples and are used throughout this guide. The time and temperature limits shown in Table 12 to explain the basis of these examples, are appropriate for the system development and system operations philosophy of some transformer owner companies. Other companies have developed and use other limits that are consistent with their philosophies. These may be the same limits as shown in Table 11. (For example: loading guides developed by some Independent System Operators (ISOs) have always used the limits in Table 11, and continue to do so.) This guide recommends that each transformer owner develop and use the limits that are consistent with their operational philosophy. An increased risk is probable for each successive loading with its attendant increased temperature. For each higher temperature, a higher risk loading condition can be assumed to be additive to any lower risk condition accepted by the user except for the short-time emergency loading. The four types of loading are as follows:

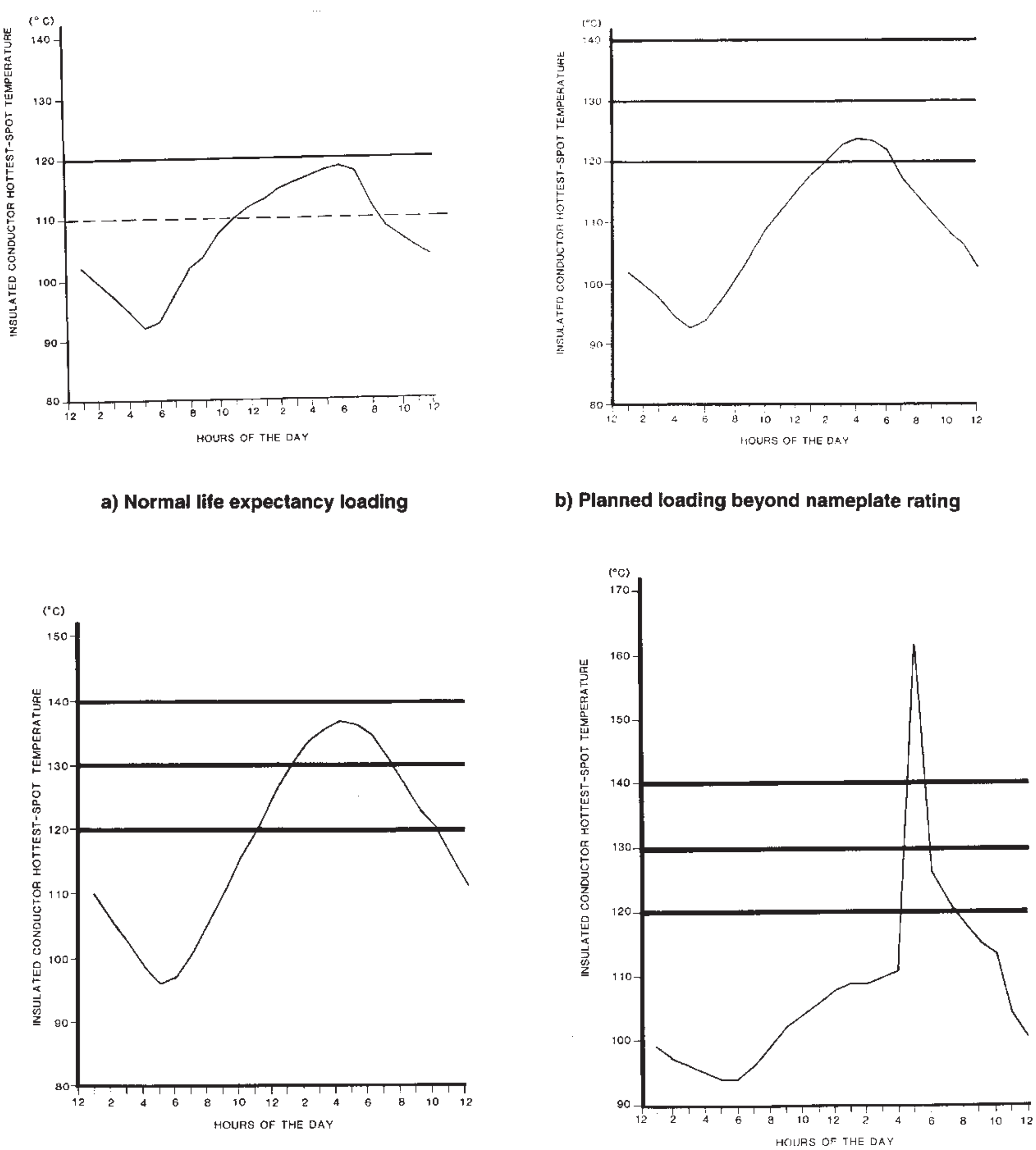
Normal estimated life

a) Normal estimated life loading

Sacrifice of estimated life

b) Planned loading beyond nameplate
c) Long time emergency loading
d) Short time emergency loading

Examples of loads that fall in these categories are illustrated in Figure 7.



c) Long-time emergency loading

d) Short-term emergency loading

Figure 7— Typical load cycles for the examples

9.2 Limitations

9.2.1 Temperature or load limitations

Suggested limits of temperatures or loads for loading above nameplate rating are given in Table 11. Suggested limits of temperature which give reasonable loss of life for the four types of loading are given in Table 12.

Table 11 —Suggested limits of temperature or load for loading above nameplate power transformers with 65 °C rise

Top-oil temperature	110 °C
Hottest spot conductor temperature	180 °C
Maximum loading	200%

Table 12 — Maximum temperature limits used in the examples in this guide

	Normal life expectancy loading	**Planned loading beyond namepla te rating**	**Long-time emergency loading**	**Short-time emergency loading**
Insulated conductor hottest spot temperature, °C	120 [a]	130	140	180 [b]
Other metallic hottest -spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature,°C	105	110	110	110

[a] 110 °C on a continuous 24 h basis (80 °C winding hottest spot rise over a 40 °C maximum ambient).
[b] Gassing may produce a potential risk to the dielectric strength of the transformer. This risk should be considered when this guide is applied refer to Annex A.
[c] The time and temperature limits shown in Table 12 to develop the examples, are appropriate for the system development and system operations philosophy of some companies. Other companies have developed and use other limits that are consistent with their philosophies.

Usually, the limits of hottest spot temperature for other metallic parts not in contact with insulation are design limits and calculated by the manufacturer when an overload specification is submitted as part of the purchasing specifications.

9.2.2 Ancillary components

Tap changers, bushings, leads, and other ancillary equipment may restrict loading to levels below those calculated by the equations in Clause 7. The user may wish to specify that ancillary equipment not restrict loading to levels below those permitted by the insulated conductor and other metallic part hottest spots. Additional information on loading of ancillary components is provided in Annex A.

9.2.3 Risk considerations

Normal estimated life loading is considered to be of minimal to “no” risk; however, the remaining three types of loading have associated with them some indeterminate level of risk. Specifically, the level of risk is based on the quantity of free gas, moisture content of oil and insulation, voltage, and loss of insulation life (useful mechanical properties). The presence of free gas, as discussed in Annex A, may cause dielectric failure during an overvoltage condition and possibly at rated power frequency voltage. The temperatures shown in Table 12 for each type of loading are believed to result in an acceptable degree of risk for the special circumstances that require loading beyond nameplate rating. A scientific basis for the evaluation of the degree of risk by a user is not currently available. Current research in model testing has not established sufficient quantitative data relationships between conductor temperature, length of time at that temperature, and reduction in winding dielectric strength. Additionally, there are other important factors that may affect any reduction, such as rate of rise of conductor temperature.

9.3 Normal estimated life loading

9.3.1 General

The basic loading of a power transformer for normal estimated life is continuous loading at rated output, when operated under usual conditions, as indicated in 4.1 of IEEE Std C57.12.00-2021. It is assumed that the operation under these conditions is equivalent to operation in an average ambient temperature of 30 °C for cooling air or 25 °C for cooling water. Normal estimated life will result from operating with a continuous hottest spot conductor temperature of 110 °C (or equivalent variable temperature with 120 °C maximum in any 24 h period). The 110 °C hottest spot temperature is based on the hottest spot rise of 80 °C plus the standard average ambient temperature of 30 °C.

Transformers may be operated above the 110 °C hottest spot temperature for short periods providing they are operated for much longer periods at temperatures below 110 °C. This is due thermal aging being a cumulative process and thus permits loads above the rating to be safely carried under many conditions without encroaching upon the normal estimated life of the transformer. The equations given in Clause 7 may be used to calculate the hottest spot and top-oil temperatures as a function of load for normal estimated life.

9.3.2 Influence of ambient temperature on normal estimated life loading

The influence of ambient temperature on normal estimated life loading is given in Clause 6.

9.3.3 Normal estimated life loading by top-oil temperature

Top-oil temperature alone should not be used as a guide for loading power transformers. The hottest spot to top-oil gradient at full load should be determined from factory tests or, lacking data a value should be assumed. The full load hottest spot to top-oil gradient should be corrected to that for actual load using Equation (18). The gradient subtracted from 110 °C will give the maximum permissible oil temperature for normal estimated life. It should be recognized that, due to thermal lag in oil rise, time is required for a transformer to reach a stable temperature following any change in load.

9.3.4 Normal estimated life loading by average winding test temperature rise

For each 1 °C in excess of 5 °C that the average winding test temperature is below 65 °C, the transformer load may be increased above rated load by the percentages given in Table 3. A 5 °C margin is used to provide a tolerance in the measurement of temperature rise. The load thus obtained is that which the transformer can carry at 65 °C rise. Since this may increase the loading beyond that contemplated by the designer, the limitations given in Table 11 and Table 12 should be checked before taking full advantage of this increased load capability.

Some power transformers are designed to have the difference between the hottest spot and average conductor temperature greater than 15 °C. This will result in an average winding temperature rise being less than 65 °C, but the hottest spot winding temperature rise may be the limiting value of 80 °C. Such transformers should not be loaded above their rating by using Table I.2. The manufacturer should be consulted for information on the hottest spot allowances used for these designs. This condition may exist in transformers with large differences (greater than 30 °C) between top and bottom oil temperatures and may be checked approximately by measuring the top and bottom radiator temperatures. Whenever possible, data on hottest spot and oil temperatures obtained from factory temperature tests should be used in calculating transformer load capability or when calculating temperatures for loads above rating.

9.4 Planned loading beyond nameplate rating

Planned loading beyond nameplate rating results in either the conductor hottest spot or top-oil temperature exceeding those suggested in Table 12 for normal estimated life loading, is accepted by the user as a normal, planned repetitive load (Figure 7b). Usually planned loading beyond nameplate rating is restricted to transformers that do not carry a continuous steady load. The suggested conductor hottest spot temperatures are presented in Table 12. Planned loading beyond the nameplate rating example is a scenario wherein a transformer is loaded such that its hottest spot temperature is in the temperature range of 120 °C–130 °C. The length of time for a transformer to operate in the 120 °C–130 °C range should be determined by loss of insulation life calculations, considering the specific load cycle. The characteristics of this type of loading are no system outages, regular and comparatively frequent occurrences, and estimated life is less than for loading within the nameplate rating.

9.5 Long-time emergency loading

Long-time emergency loading results from the prolonged outage of some system element and causes either the conductor hottest spot or the top-oil temperature to exceed those suggested for planned loading beyond the nameplate rating. This is not a normal operating condition but may persist for some time. It is expected that such occurrences will be rare. Long-time emergency loading may be applied to transformers carrying continuous steady loads, but the loss of insulation life must be determined to be acceptable by a user. Suggested conductor hottest spot temperatures are presented in Table 12. Top-oil temperature should not exceed 110 °C at any time.

The long-time emergency loading example is a scenario wherein a power transformer is loaded such that its hottest spot temperature is in the temperature range of 120 °C–140 °C. The characteristics of this type of loading are one long-time outage of a transmission system element, two or three occurrences over the normal lifetime of the transformer, where each occurrence may last several months, and the risk is greater than the planned loading beyond nameplate rating. Figure 7c illustrates an example of a long-time emergency loading profile. The hottest spot temperature for this example exceeds 120 °C. Calculations should be made to determine if the loss of insulation life is acceptable for the specific load cycle.

9.6 Short-time emergency loading

Short-time emergency loading is an unusually heavy loading brought about by the occurrence of one or more unlikely events that seriously disturb normal system loading. This causes either the conductor hottest spot or top-oil temperature to exceed the temperature limits suggested for planned loading beyond name-plate rating. Acceptance of these conditions for a short time may be preferable to other alternatives. Suggested conductor hottest spot temperatures are presented in Table 12. Top-oil temperature should not exceed 110 °C at any time. This type of loading, with its greater risk, is expected to occur rarely.

Short-time emergency loading example is a scenario wherein a transformer is so loaded that its hottest spot temperature is as high as 180 °C for a short time. The characteristics of this type of loading are a series of unlikely conditions on the transmission system (second or third contingency), one or two occurrences over the normal lifetime of the transformer, and the risk is greater than for long-time emergency loading. Calculations should be made to determine if the loss of insulation life during the short-time emergency is acceptable for the specific load cycle. Figure 7d illustrates an example of a short-time emergency loading profile. This figure presents a temperature curve that had leveled off for the day until about 4 p.m. when a system condition occurs that loads the transformer so that its hottest spot temperature rises rapidly to 163 °C in 1 h.

9.7 Loading information for specifications

If the maximum load capacity that a transformer user plans to utilize on a intended or emergency basis is included in the specifications at the time of purchase, the following information should be given:

1. Load
    a. Two step load cycle approach Prior steady-state load, percent of maximum nameplate rating
        i. Maximum load, percent of maximum nameplate rating
        ii. Duration
    b. Load cycle over a 24 h period
2. Ambient temperature, °C
    a. Constant for load cycle approach [see item 1a)]
    b. Variable over the load cycle for load cycle approach [see item 2a)]
3. Type of loading, planned or emergency, long-time or short time
4. Limiting top-oil temperature
5. Limiting hottest spot temperature
6. Statement that ancillary components do not limit the loading capability

More than one set of loading conditions may be used. The load cycle with limiting top-oil and hottest spot temperatures determines loss of life, which may be calculated.

9.8 Operation with part or all the cooling out of service

When auxiliary equipment, such as pumps or fans, or both, is used to increase the cooling efficiency, the transformer may be required to operate for some time without this equipment functioning. The permissible loading under such conditions is given in Annex H.

10. Rating and Loading Capability

10.1 General

During the last few decades, energy regulators, electric reliability organizations, and national energy market operators have required electricity network businesses to provide equipment's thermal ratings to help ensure reliable and secure transmission and distribution systems operation. Accurate ratings are needed for effective operating, planning, and maintaining the energy networks.

Generally, the rating is the operational limit of a transmission system element under specified conditions. A transformer is one such element.

This section of the Guide introduces the meaning of transformer thermal rating and explains the difference between nameplate ratings and other types of ratings that evolved in the last years. Also, a relationship between transformer loading capability and thermal ratings is addressed.

10.2 Types of transformer ratings

10.2.1 Nameplate rating

Per IEEE Std C57.12.00-2021 "the rated kVA of a transformer shall be the output that can be delivered for the time specified at rated secondary voltage and rated frequency without exceeding the specified temperature-rise limitations under prescribed conditions of the test and within the limits of established standards".

Nameplate ratings can be seen as static, contrary to dynamic ratings introduced later in this section.

For transformers in poor condition, or with excessive water content, the rating should be limited to the nameplate rating.

10.2.2 Normal cyclic rating

Adapting the definition from the NERC dictionary [B27], the normal cyclic rating is the rating as defined by the transformer owner that specifies the level of electrical loading, usually expressed in the units of apparent power (kVA) or current (A), that a transformer can support or withstand through the daily demand cycles without loss of its insulation life. Normal cycling rating assumes loading above nameplate rating for a limited time so that loading under nameplate rating would compensate for the loss of life during overload.

The normal cyclic rating is also known as the continuous rating.

10.2.3 Emergency rating

Adapting the definition from the NERC dictionary [B27], the emergency rating is the rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in the units of apparent power (kVA) or current (A), that a transformer can support or withstand for a finite period. The emergency rating assumes an acceptable loss of transformer life.

The types of emergency ratings vary from one network to another and are set according to the network's rating methodology as required by NERC FAC 008-5 [B29]. A Regional Transmission Organization (RTO) Guide for determination of 'power transformer load capability ratings' [B30] and one utility rating methodology [B31] are good examples.

10.2.3.1 Long-time emergency rating

Like the emergency rating, the long-time emergency rating is defined as the maximum load in MVA a transformer can sustain during the time of a long-term contingency event. This could be a lead time to replace another transformer or an overhaul of one substation transformer working in parallel with another.

10.2.3.2 Short-time emergency rating

The short-time emergency rating is usually applied to post contingency events lasting a limited period, not exceeding 24 hr.

10.2.4 Load-shed Rating

Also known as load dump rating, the load-shed rating is usually a 15 min short-time emergency rating. It is acknowledged that the thermal models of this guide may not be very accurate when calculating top oil and hottest spot temperatures for such a short interval. The approach used in [B32] can be followed when facing this kind of challenge.

10.2.5 Seasonal Rating

Seasonal ratings are static limits that change from one season (e.g. winter) to another (e.g. summer). Seasonal ratings are dependent on ambient temperature daily cycle for a particular location/region.

10.2.6 Day-Night Ratings

Day-Night ratings are static limits that change two times per day depending on ambient temperature during night or day. 24-hour ambient temperature curves account for daily temperature cycles reducing the need for recognition of daytime versus night-time ratings for oil-filled equipment. Solar and wind impacts are minimal.

10.2.7 Ambient Adjusted Ratings

Recently, a transformer rating falls under category of transmission line rating as one of the elements of transmission line system. The meaning of transmission line is extended from its traditional definition to include power equipment such as transformers.

FERC Order 881 [B33] established the following definition of Ambient-Adjusted Rating:

Ambient-Adjusted Rating" (AAR) is a Transmission Line Rating that:

— Applies to time period of not greater than one hour.
— Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
— Reflects the absence of solar heating during night-time periods, where the local sunrise/sunset times used to determine daytime and night-time periods are updated at least monthly, if not more frequently; and
— Is calculated at least each hour, if not more frequently.

10.2.8 Real-time (Dynamic) rating

The concept of real-time (dynamic) transformer rating (DTR) has been evolving since this term was introduced for overhead lines in [B34]. It should be noted that a real-time (dynamic) thermal rating was first applied to transmission lines, but later was used for transformers and other power equipment ,representing an element of transmission system.

The real-time (dynamic) rating is defined as the maximum load possible without exceeding predefined temperature and current limits, based on real-time measured ambient and transformer temperatures, cooling system status and load.

From the definition, it follows that real-time rating should only be implemented with an adequate monitoring equipment installed on a transformer, this includes a weather station in the proximity.

10.3 Loading

Transformer loading is operating a transformer under continuously variable load expressed in the units of apparent power (kVA) or current (A). Clause 8 and 9 are devoted to loading under various conditions.

10.3.1 Loading capability

The loading capability is the maximum load that can be carried for a specified time at the given ambient temperature, which results in acceptable loss of life while not exceeding the permissible temperature and current limits. Loading capability can be calculated at any time, provided the ambient temperature, and load profiles are known or predicted.

Like rating, loading capability can be estimated for normal continuous cycling and short- and long-term emergency loading. These types of loading are addressed in clauses 8 and 9.

10.3.2 Load duration curve and real-time rating

To better understand the difference between static and dynamic rating, refer to Figure 8, which illustrates the advantage of dynamic rating and the way it could be graphically presented.

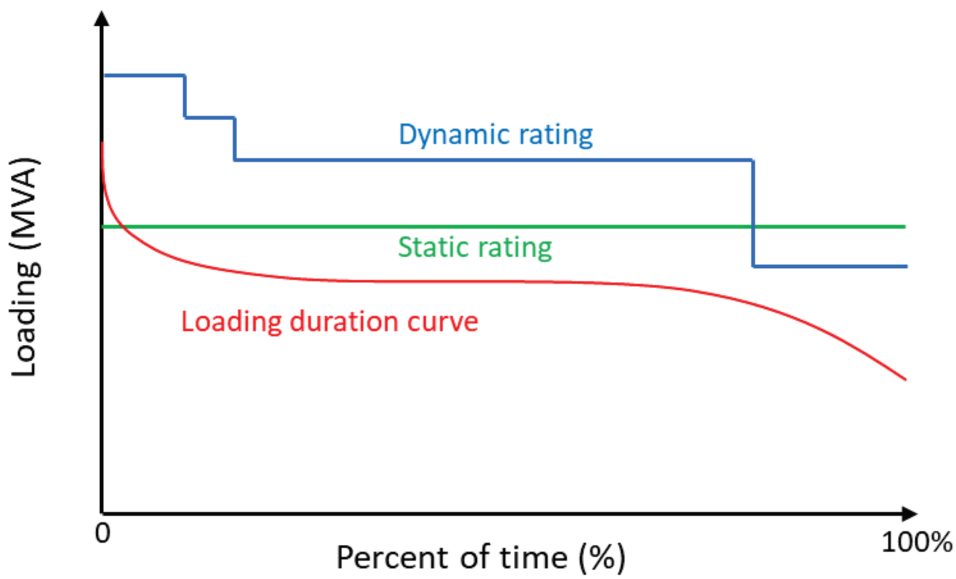


Figure 8— Loading duration curve superimposed with static and dynamic ratings

The red line in the figure is the load duration curve. The load duration curve (LDC) is defined as the function of the load versus time, in which the ordinates representing the load in MVA, plotted in the order of decreasing magnitude, i.e., with the greatest load at the left and the lowest loads at the time extreme right.

The green line is the static (nameplate) rating, and the blue line is the dynamic rating.

10.4 The interrelationship between loading capability and rating

Often, the real-time (dynamic) rating and load capability are used interchangeably. This is not always appropriate. The main difference between these terms lies in the mathematical function describing loading capability and rating. The loading capability is the continuous function of time, while as rating is the discontinuous (discrete) function, meaning that there are step changes in the curve representing ratings (see Figure 7). The real-time rating based on continuous ambient and other key transformer temperatures measurement may coincide with loading capability.

The rating is based on loading capability considering the condition of a transformer and its components. This includes ancillary components such as LTC and bushings. Ratings are assigned by the asset owner.

10.5 Example of transformer rating methodology

Rating methodologies will vary from one network operator to another. The following shares an example by one utility of a one rating methodology by one utility [B31]. Transformer ratings are part of the facility rating methodology required by NERC standard FAC-008-5 [B29].

This example facility rating methodology was developed using a seasonal load cycle with peak ambient temperatures of [105, 100, 95, 90, 80, 70, 60, 50, 40, 32, 20, 10, and 0] degrees Fahrenheit. or [41, 38, 35, 32, 27, 21, 16, 10, 4, 0, -7, -12, -18 degrees Celsius].

Types of Rating and time duration for rating are chosen as follows:

— **Continuous** – available peak load ability of a transformer for a given daily peak ambient temperature and load cycle curve which can be repeated indefinitely.
— **1 year** – available peak load ability of a transformer for a given daily peak ambient temperature and load cycle curve which can be repeated for up to one year. The intent of this rating is for usage on transformers that may have reached planning maximum capacity sooner than expected and a project must be developed to increase capacity.
— **12 hours** – available contingency load ability of a transformer for a given daily peak temperature using the continuous rating as a pre-load to allow a transformer to carry a larger load for up to 12 hours to allow for switching of load, installation of a mobile transformer, etc.
— **2 hours** – available contingency load ability of a transformer for a given daily peak temperature using the continuous rating as a pre-load to allow a transformer to carry a larger load for up to 2 hours to allow for switching of load.
— **15 minutes** – available contingency load ability of a transformer for a given daily peak temperature using the continuous rating as a pre-load to allow a transformer to carry a larger load for up to 15 minutes to allow for switching of load.

All together 65 ratings representing 13 temperature cycles with 13 peaks and 5 durations with the following limitation:

— Load Tap Changers
— Internal Leads, Connections, and DETC
— Stray Flux
— Moisture

Annex A

(informative)

Mathematical model of vapor bubble evolution during transformer overload

A.1 Mechanism of gas bubble formation

When a transformer winding conductor temperature reaches a temperature at which gas bubbles start to evolve, the dielectric property of the oil-paper insulation is said to be compromised. At this point, the probability of dielectric failure sharply increases. The temperature at which the first few bubbles appear is known as the bubble inception temperature (BIT).

For a gas bubble to form and grow within a volume of insulating liquid, the gas within the bubble must develop an internal pressure sufficient to overcome the forces constraining it, namely, the interfacial tension force of the liquid, the gravitational force acting on the column of liquid above the bubble, and the force of the atmospheric pressure acting on the surface of the liquid [B35].

The interfacial tension force is related to the so-called Laplace pressure caused by the surface tension of the interface between the insulating liquid and free gas composed of water vapor and other gases present in the oil/paper insulation system.

The Laplace pressure is determined from the Young–Laplace equation given as:

$$\Delta P \equiv P_{inside} - P_{outside} = \frac{2\sigma}{r}, \tag{A.1}$$

where

r	is the radius of a bubble
σ	is the surface tension.

T.V. Oommen [B36] emphasized the importance of the Laplace pressure when considering prediction of BIT. Thus, it was included in Annex A of [B37]. However, as could be calculated from (A.1) a 1 mm bubble has negligible extra pressure (0.00284 atm at σ = 72 mN/m and 25 °C. Yet when the bubble diameter is ~3 µm, the bubble has an extra atmosphere inside than outside. These super tiny bubbles are hardly observable and most probably present no harm to the integrity of the insulation.

A.2 Bubble Inception Temperature

The major contribution to the external pressure which a bubble must overcome is from the static atmospheric pressure and from the pressure caused by the liquid column above the bubble.

The bubble inception temperature can be derived from work by Fessler et.al [B38] solving (7) for temperature as:

$$\theta_{bubble} = \left[\frac{7069}{22.95 + 1.4959 \ln WCP_a - \ln(P_{tot})}\right] - 273.15, \tag{A.2}$$

where

θ_{bubble}	is the bubble inception temperature in Celsius.

P_{tot} is the total pressure which bubble must overcome to evolve, mmHg, and

WCP_a is the active water content of paper as defined by (4.1) in [B39] in percentage. This is the same as water concentration **C** from [B39].

The difference of this equation from that given in [B36],[B37] is that it has no additional term related to partial gas pressure due to possible presence of other gases. As explained in Hill et.al [B40], the extra term given in previous Annex A would only have an impact under condition of high moisture content of the conductor wrapping paper. Even for the very wet transformer the moisture content at the high temperature location would not exceed 2% [B37], at which the extra pressure term is negligible. For this reason, it is not included in (A.2).

The general form of (A.2) is given by (A.3).

$$\theta_{bubble} = \left[\frac{n\cdot B}{n\cdot\ln\left(\frac{1}{A}\right)+n\cdot\ln(WCP)-\ln(P_{tot})}\right] - 273.15, \tag{A.3}$$

The parameters of multiple regression model obtained by Fessler et.al [B38] are presented in the Table 1 in the first three rows.

Table A.1—-The parameters of multiple regression model of (A.3)

Parameters	Value
A	$2.173 \cdot 10^{-7}$
B	4725.6
f	0.6685
$n = 1/f$	1.4959
$n{\cdot}B$	7069
$n{\cdot}ln(1/A)$	22.95

In (A.3) and Table A.1, A and B are empirical constants for new Kraft paper. f is the exponent of the pressure term in the original Freundlich isotherm [B38]. It should be noted that when deriving the bubble temperature equation from (7) of [B38] the mathematical error in (8) of [B38] was propagated into equation (A.2) of former Annex A of [B37]. The error has been corrected in this edition.

A.3 Determination of equation (A.3) parameters

There are two variables to be determined before use of equation (A.3)

1. External pressure acting on the bubble (P_{tot}) and
2. Water content of paper at the location of interest. ($WCPa$).

1. The external pressure acting on the bubble is the sum of atmospheric pressure for constant pressure preservation system (COPS) and hydrostatic pressure of the oil column above the bubble.

$$p = \rho \cdot g \cdot h + p_0, \tag{A.4}$$

where p is the hydrostatic pressure; ρ is the density of the oil; g = 9.80655 m/s² gravitational acceleration; h is the depth from the surface of the oil to the bubble;.p_0 is external (usually the atmospheric pressure at sea level (760 mmHg).

The water content of the wrapping paper could be determined by measuring relative saturation and temperature at the top oil level for a prolonged time and using one of the methods described in IEEE C57.162 Moisture Guide. [B39]

A.4 Factors affecting bubble inception temperature

The following factors have an impact on the parameters and structure of the bubble model [B41, B42]:

- The water content of oil (mg/kg) at the interface with the paper
- Porosity and capillary property of cellulose at the oil/hottest spot interface
- The surface tension of oil
- The temperature gradient of oil-paper interface
- Rate and amplitude of winding temperature rise to reach BIT
- Static head pressure of the liquid above the area of bubble formation
- Other dissolved gas content of the oil apart from the water vapor
- Type of the oil preservation system
- Aging state of cellulose and oil
- Altitude

The consideration of many of the above parameters is still a subject of ongoing research [B40]. A more comprehensive account for various listed parameters may substantially change the equation (A.2) and (A.3) and overcome many limitations of the presented here BIT model.

A.5 Limitations of bubble inception temperature (BIT) model

During the last few decades, it has been learned that the model (A.2) has the following limitations:

a) (A2) and (A.3) are derived from a water vapor sorption isotherm, meaning that a steady-state model is used, while among factors affecting the BIT, the rate of change in hottest spot temperature during overload has a profound effect on BIT.

b) Sorption isotherm (A.3) is developed under thermodynamic equilibrium conditions, which are hardly ever experienced by an operating transformer.

c) The (A.2) equation is based on an adsorption part of the sorption hysteresis loop, while the bubble evolution can only occur on the desorption part of the loop.

d) (A.2) and (A.3) are based on the Freundlich sorption isotherm (type I(b) according to the IUPAC classification). This isotherm provides a reasonable fit to experimental data up to water-in-paper activity A_{wp}=0.5. The better and more physically sound fit is provided by the type II isotherm per the IUPAC classification [B43]. The Guggenheim Anderson de Boyer (GAB) model was successfully fitted by Roizman [B42] and later confirmed by Przebulek [B49].

e) The parameters of Table 1 are only valid for new mineral oil and thermally upgraded new kraft paper. The parameters will need to be adjusted/modified every time the aging characteristics of paper or oil change.

A.6 Example

The following example illustrates the use of Equations (A.2) and (A.3).

Assume 2% water in the paper insulation in the vicinity of a hottest spot. To compute the bubble inception temperature from a winding at a depth of 2.45 m the oil head must be added to the pressure in the gas space above the oil. For the free-breathing transformer, the following data is assumed:

- Water-in-paper, $WCPa = 2$ %
- Atmospheric pressure, = 760 mmHg
- Oil head (2.45 m) = 164 mm Hg (using a conversion of liquid depth/level to hydrostatic pressure calculator)
- Total pressure, $P_{tot} = 924$ mmHg

Substituting these data in (A.2) results in $\Theta_{bubble} = 138.6$ °C. This value confirms the old standing view: to avoid bubbling, the hottest spot temperature should not exceed 140 °C, assuming that for the middle-aged transformer, moisture content of paper at a level of top oil temperature can reach 2%. See Figure A1.

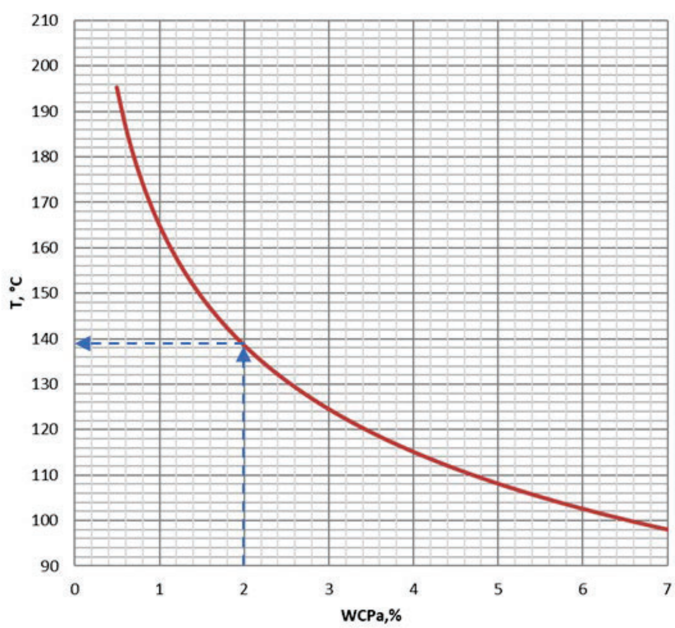


Figure A.1— Bubble inception temperature at different moisture content

However, if the paper moisture content is equal to 0.5%, the bubble inception temperature is well above 180 °C, which could stand as a limit for dry/new insulation. The BIT also will be lower if evaluated by formula A3 with the coefficients for aged paper.

Some earlier published papers on bubble evolution have stated that 140 °C is the bubble evolution temperature, but the moisture content was not reported [B46].

Moisture content appears to be the most critical parameter in determining bubble evolution temperature.

However, direct moisture determination would require a paper sample, especially from the hottest spot region, which is seldom achievable. The estimation of water content within the transformer oil-paper complex is not a trivial task. More detailed methods and approaches can be found in [B39].

Annex B

(normative)

Effect of loading transformers above nameplate rating on bushings, tap changers, and auxiliary components

B.1 Bushings

B.1.1 General

The following discussion applies to oil-impregnated, paper-insulated, capacitance-graded bushings only. For other bushing types, consult with the manufacturer for loading guidelines. Bushings are normally designed with a hottest- spot total temperature limit of 105 °C at rated bushing current with a transformer top-oil temperature of 95 °C averaged over a 24 h time period. Operating a transformer beyond nameplate current can result in bushing temperatures above this limit, which cause bushing loss-of-life depending on the actual time-temperature profile the bushing sees.

A number of factors that reduce the severity of bushing overloads compared to transformer winding insulation overloads include the following:

— Transformer top-oil temperature may be well below 95 °C at rated transformer output.

— Bushings are sealed units preserving insulation and thermal integrity.

— Bushing insulation is usually drier than transformer insulation.

— Bushing insulation is not significantly stressed by fault-current forces.

— The use of bushings with higher current ratings than the connected transformer windings.

Possible bushing overload effects include the following:

— Internal pressure build-ups

— Aging of gasket materials

— Unusual increases in power factor from thermal deterioration

— Gassing caused by hottest spots in excess of 140 °C

— Thermal runaway from increased dielectric losses at high temperatures

— Heating in metallic flanges due to stray magnetic flux

In most cases, bushings are applied at less than rated top-oil temperature and in many cases the transformer rated current is less than the bushing rated current. Due to the fact that the bushings do not have any active cooling methods such as fans, oil circulation pumps and radiators that are commonly utilized by transformers, it is suggested the user consider bushings with a current rating the same or higher than the maximum transformer overload current so the transformer overloading capability is not compromised by the bushing selected.

B.1.2 Draw leads in bushings

Some bushings are designed for a solid or hollow copper rod inside the bushing to give the full bushing rating. Some bushings are also designed to substitute a draw lead cable for the conductor inside the bushings. When a bushing is operated in the draw lead mode, the thermal performance is determined by the size of the lead supplied as part of the transformer, and the nameplate rating of the bushing may not apply. The draw leads may limit transformer loading to less than the capability of the transformer winding insulation or the capability of the bushing.

B.2 Tap-changers

B.2.1 De-energized tap changer (DETC)

IEEE C57.131 addresses the design temperature rise of the contacts for DETCs including an overload capacity of 1.2 times the maximum rated through current. The rise will also depend on the design of contacts and the "condition" of the contacts when the loading occurs. Although tap-changer contacts may have certain overload capabilities when new, these capabilities may decrease due to a thin film build-up on the contacts that occurs during normal service. Once a contact reaches a critical temperature, a thermal runaway condition can occur. The contacts overheat and a deposit builds up around the contacts, increasing contact resistance until it finally reaches a temperature that will generate gas. As a minimum, this will produce a gas alarm. As a maximum, the gas may trigger a dielectric failure of the transformer.

The thin film build-up described above can be effectively controlled if the DETC is operated a minimum of once a year. This can be done during an outage for maintenance or whenever the transformer is de-energized to change taps. Whenever this opportunity occurs, the DETC should be operated across its full range approximately 10 times to help ensure that all the contacts have been wiped clean. With clean contacts, the problem of thermal runaway and deposit buildup during overload conditions can be minimized. After operation of the DETC it would be good industry practice to perform electrical tests of the transformer to confirm correct operation and final position of the DETC prior to re-energization.

If, in the transformer owner's experience, the de-energized tap-changer has been operated periodically without problems, the previous paragraph is recommended to help ensure that the contacts will remain in the best possible condition. However, if, in the owner's experience, the de-energized tap changer has not proven to be completely reliable (because of misalignment of the contacts or failure of the mechanized mechanism), the owner may not wish to operate it under any circumstances.

The decision to follow the recommendation of the above paragraph should be tempered by the actual experience with each transformer.

B.2.2 Load tap-changers

IEEE Std C57.13 [B47] and IEC 60214 [B48] provide the basis for the rating of a load tap-changer. Most North American transformer manufacturers have complied with the requirements of IEC 60214 [B48] prior to the approval of IEEE Std C57.131 [B47]. The manufacturer should be consulted to assure that a specific LTC has been designed to these standards.

According to both standards, the basis for the current rating of an LTC includes the following:

a) Temperature rise limit of 20 °C for any current carrying contact in oil when operating at 1.2 times the maximum rated current of the LTC.
b) Capable of 40 breaking operations at twice maximum rated current and kVA. Oscillograms taken for each operation should indicate that in no case is the arcing time such as to endanger the operation of the apparatus.

Standards allow tap-changer contacts to work in 100 °C oil with a temperature rise of 20 °C at 1.2 times the nameplate rating. Also, experience has shown that carbon starts to develop on contacts in oil at elevated temperatures (in the order of 120 °C). How serious this growth of carbon becomes depends on the wiping action of the switch contacts, the frequency that switch operation takes place, and how long the high temperature persists. Another important factor is whether the LTC is in the main tank or in a separate compartment. Usually, arcing contacts of the LTC are located in a separate compartment and the oil temperature is less than 100 °C.

Contact temperature rise over oil can be estimated using the following equation:

$$\Delta\Theta_c = \Delta\Theta_{c,R} \times K^n \tag{B.1}$$

where

$\Delta\Theta_c$	is the contact temperature rise over oil at per-unit load K, °C
$\Delta\Theta_{c,R}$	is the contact temperature rise over oil at rated current, °C
K	is the load through the LTC in per unit of LTC current rating
n	is the exponent of contact temperature rise and may vary over a range of 1.6–1.85. If an exact exponent, based on test results, is not known, a value of 1.8 may be used.

Total contact temperature can then be determined as follows:

$$\Theta_c = \Theta_A + \Delta\Theta_{TO,LTC} + \Delta\Theta_c \tag{B.2}$$

where

Θ_c	is the total contact temperature, °C
ΘA	is the ambient temperature, °C
$\Delta\Theta_{TO,\ LTC}$	is the oil temperature rise over ambient in LTC compartment at per-unit load K, °C
$\Delta\Theta_c$	is the contact temperature rise over oil, °C

The top-oil temperature in the LTC compartment may not be readily available unless the LTC is located in the main tank of the transformer. If the LTC is located in a separate tank, the LTC oil may be in the order of 5–15 °C cooler than the top-oil temperature in the main tank at rated load. As a rule of thumb, it can usually be assumed that the temperature rise of the oil in a separate tank is 80% of the oil temperature rise in the main tank.

The following is an example using the previous equations for the case where the LTC is located in a separate compartment. This calculation shows that the LTC could carry an emergency load of as high as 1.32 pu at an ambient of 30 °C before a contact temperature of 120 °C is reached. This assumes that, per the standards, the temperature rise of the contacts is 20 °C at 1.2 times the maximum rated load and that the oil temperature rise in the separate compartment is 66 °C at 1.32 pu load.

$$\Delta\Theta_{c,R} = \frac{\Delta\Theta_c}{K^n} = \frac{20}{(1.2)^{1.8}} = 14.4\ ^\circ C \tag{B.3}$$

where

K	is the ratio of load L to rated load, per unit
n	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for the effects of change in resistance with change in load. See 1.
$\Delta\Theta_c$	is the contact temperature rise over oil, °C
$\Delta\Theta_{c,R}$	is the contact temperature rise over oil at rated load, °C

Θ_A	is ambient, °C	= 30 °C
$\Delta\Theta_{TO,\ LTC}$	is the oil rise in LTC compartment (80% of top-oil rise of 82 °C at 1.32 pu load), °C	= 66 °C
$\Delta\Theta_c$	is the maximum contact temperature rise = $14.4 \times (1.32)^{1.8}$, °C	= 24 °C
	Total	120 °C

Some LTC manufacturers have advised caution about using the above approach. One caution is that the cooling ability of the contact geometry and contact mass are also important to consider. In addition, it is not physically possible to measure the temperature at the contact point. What is measured is a point close to the contact point. The temperature of the actual contact point will be considerably higher. A well-designed transformer will have an LTC capable of carrying the same load as the core and coils. That is, the hottest spot temperature in the transformer will be the limitation to loading, not the LTC contact temperature. If this is the case, calculations as shown above would not be necessary. However, such calculations may be useful if the LTC limits the output of the transformer.

LTCs designed in accordance with IEEE Std C57.131 [B47] and IEC standards must be capable of 40 breaking operations at twice maximum rated current and kVA. The user would be wise, however, to exercise caution before operating an LTC in this fashion. It should be realized that a factory test is made under ideal conditions (new oil, new contacts, recently adjusted, etc.). Most LTC manufacturers would agree to a few operations per year at twice rated current and kVA. As the number of operations at twice rated current increases, not only would there be additional contact deterioration, but the likelihood of failure of the LTC would also increase. The wear of contacts and contamination of oil increases rapidly with current. Higher overloads on an LTC will necessitate more frequent maintenance.

B.3 Bushing-type current transformers

B.3.1 General

In their normal location, bushing-type current transformers have the transformer top-oil as their ambient, which is limited to 105 °C total temperature at rated output for 65 °C rise transformers. Loading the power transformer beyond nameplate results in an increase in top-oil temperature and secondary current in the current transformer with an associated temperature rise.

A factor in reducing the severity of the current transformer overload is that the top-oil temperature at rated transformer output may be well below 105 °C. In cases where consideration of the loading and top-oil temperature rise of the power transformer and the current in the current transformer indicates the possibility of excessive operating temperatures in the current transformer, the manufacturer should be consulted on the current transformer capability before loading beyond its nameplate rating. The capability of bushing current transformers under operating conditions cannot necessarily be derived from the rating factor.

It may also be possible to select higher current transformer ratios to reduce secondary currents and thus increase the capability of the current transformer.

B.4 Insulated lead conductors

Within the transformer, connections to tap-changer and line terminals and other internal connections are made with insulated leads and cables. The method of calculating the hottest spot temperature for these leads is different from that employed for the windings. However, the same hottest spot limits apply equally for both windings and leads since similar insulating materials are normally used. Generally, the loading of the transformer will not be limited by the lead temperature rise. Recommendations of the manufacturer should be sought if proposed loading cycles are in excess of original specifications for the transformer.

Annex C

(informative)

Calculation methods for determining ratings and selecting transformer size

C.1 General

A transformer application problem usually needs to answer the question, "Is an available transformer suitable for a given load cycle?" Calculations required to answer this question can be made by hand, or a computer program can be written to automate the calculation. This annex will illustrate calculation procedures used for the determination of loading limits and the selection of a transformer rating. It should be noted that the purpose of the illustration is to show one way to approach the problem. As in most engineering problems, different approaches are possible and judgment must be used in interpreting the results. The principles outlined in the following examples can be applied to all sizes and ratings of transformers. The calculation methods of Annex I may be used to determine if the loss of insulation life for these examples is acceptable.

C.2 Calculation determining loading beyond nameplate rating of an existing transformer

For this example, a 65 °C rise triple rated, ONAN/ODAF/ODAF directed forced-oil cooled transformer rated 112 000/149 333/186 666 kVA will be used. A load profile is given (see Table C.1, normal load in per unit) for a day starting at 6:00 a.m. The hottest spot winding temperature profile will be determined by calculation. Some simplifying assumptions will be made to make the calculation easier. The first assumption is that maximum cooling will be used throughout the day, even though at the lowest part of the load cycle, the loading will be less than the intermediate rating. The assumption may be optimistic; on the other hand, when loading beyond nameplate rating is planned, it is reasonable to assume that every measure is taken to assist the transformer, including the use of maximum cooling throughout the day.

For the directed forced oil cooling, the n exponent is 1 and no correction of the time constant is required. That is,

$$\tau_{TO} = \tau_{TO,R} \tag{C.1}$$

where

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

For cooling modes with $n < 1$ the time constant should be corrected and this refinement is easily accomplished with a computer program.

The third assumption is that the load is kept constant during the following hour. For the rising part of the load curve this assumption will give loads that are too low, but on the falling part of the load curve loading values that will be too high. It is possible to refine the load representation when there is need.

The last assumption is that the ambient temperature is constant during the day.

Table C.1— Load cycles and temperature rises for 187 MVA transformer

	Normal load					PLBN				LTE				STE			
Hour	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H
6	0.52	18.14	19.20	7.73	56.9	0.66	26.86	12.46	69.3	0.66	26.86	12.46	69.3	0.66	26.86	12.46	69.3
7	0.55	17.14	17.94	8.65	56.6	0.69	24.91	13.62	68.5	0.69	24.91	13.62	68.5	0.69	24.91	13.62	68.5
8	0.61	16.63	17.23	10.63	57.9	0.77	23.75	16.96	70.7	0.77	23.75	16.96	70.7	0.77	23.75	16.96	70.7
9	0.70	16.76	17.21	14.01	61.2	0.88	23.74	22.15	75.9	0.88	23.74	22.15	75.9	0.88	23.74	22.15	75.9
10	0.79	17.74	18.07	17.85	65.9	1.00	25.08	28.60	83.7	1.00	25.08	28.60	83.7	1.00	25.08	28.60	83.7
11	0.85	19.47	19.71	20.66	70.4	1.07	27.76	32.74	90.5	1.07	17.76	32.74	90.5	1.07	27.76	32.74	90.5
12	0.90	21.49	21.67	23.17	74.8	1.13	30.85	36.52	97.4	1.13	30.85	36.52	97.4	1.13	30.85	36.52	97.4
13	0.93	23.66	23.79	24.74	78.5	1.17	34.14	39.15	103.3	1.29	34.14	39.15	103.3	1.92	34.14	39.15	103.3
												47.59	111.7		a	a	a
14	0.96	25.69	25.79	26.36	82.2	1.21	37.29	41.87	109.2	1.33	39.48	50.59	120.1	1.33	46.76	50.59	127.4
15	0.98	27.64	27.71	27.47	85.2	1.23	40.36	43.27	113.6	1.36	44.27	52.90	127.2	1.36	49.73	52.90	132.6
16	0.99	29.39	29.44	28.03	87.5	1.25	43.03	44.69	117.7	1.38	48.46	54.47	132.9	1.38	52.55	54.47	137.0
17	1.00	30.84	30.88	28.60	89.5	1.26	45.40	45.41	120.8	1.39	52.01	55.26	137.3	1.39	55.07	55.26	140.3
18	1.00	32.08	32.11	28.60	90.7	1.26	47.36	45.41	122.8	1.39	54.87	55.26	140.1	1.39	57.17	55.26	142.4
19	0.98	33.01	33.03	27.47	90.5	1.23	48.83	43.27	122.1	1.23	57.02	55.26	142.3	1.23	58.74	55.26	144.0
												43.27	130.3			43.27	132.0
20	0.97	33.41	33.43	26.91	90.3	1.22	49.38	42.57	122.0	1.22	55.52	42.57	128.1	1.22	56.81	42.57	129.4
21	0.94	33.57	33.58	25.27	88.9	1.18	49.61	39.82	119.4	1.18	54.21	39.82	134.0	1.18	55.18	39.82	125.0
22	0.90	33.26	33.27	23.17	86.4	1.13	49.07	36.52	115.6	1.13	52.52	36.52	119.0	1.13	53.25	36.52	119.8
23	0.86	32.49	32.49	21.15	83.6	1.08	47.81	33.36	111.2	1.08	50.39	33.36	113.8	1.08	50.94	33.36	114.3
24	0.81	31.39	31.39	18.76	80.2	1.02	46.04	29.76	105.8	1.02	47.98	29.76	107.7	1.02	48.39	29.76	108.2
1	0.68	29.94	29.94	13.22	73.2	0.86	43.78	21.15	94.9	0.86	45.23	21.15	96.4	0.86	45.54	21.15	96.7
2	0.61	27.42	27.42	10.64	68.1	0.77	39.85	16.96	86.8	0.77	40.94	16.96	87.9	0.77	41.17	16.96	88.1
3	0.58	24.86	24.86	9.62	64.5	0.73	35.82	15.24	81.1	0.73	36.63	15.24	81.9	0.73	36.81	15.24	82.1
4	0.55	22.67	22.67	8.65	61.3	0.69	32.35	13.62	76.0	0.69	32.96	13.62	76.6	0.69	33.09	13.62	76.7
5	0.53	20.78	20.78	8.03	58.8	0.67	29.33	12.84	72.2	0.67	29.78	12.84	72.6	0.67	29.88	12.84	72.7
6	0.52	19.20	19.20	7.73	56.9	0.66	26.86	12.46	69.3	0.66	27.20	12.46	69.7	0.66	27.27	12.46	69.7

[a] See C.5 for temperature rises at 13:30 h.

The transformer characteristics at 187 MVA are as follows:

Top-oil rise over ambient at rated load	$\Delta\Theta_{TO,R}$ = 36.0 °C
Hottest spot conductor rise over top-oil temperature, at rated load	$\Delta\Theta_{HS,R}$ = 28.6 °C
Ratio of load loss at rated load to no-load loss	R = 4.87
Oil thermal time constant for rated load	$\tau_{TO,R}$ = 3.5 h
Exponent of loss function vs. top-oil rise	n = 1.0
Exponent of load squared vs. winding gradient	m = 1

The ultimate top-oil rise over ambient for load K will be, according to Equation (24).

$$\Delta\Theta_{TO,U} = \Delta\Theta_{TO,R}\left[\frac{K_U^2 R + 1}{(R+1)}\right]^n \tag{C.2}$$

$$\Delta\Theta_{TO,U} = 36\left[\frac{K_U^2(4.87)+1}{(4.87+1)}\right]^n \tag{C.3}$$

$$\Delta\Theta_{TO,U} = 29.87K_U^2 + 6.13 \tag{C.4}$$

where

K_U is the ratio of the ultimate load L to rated load, per unit
R is the ratio of load loss at rated load to no-load loss on the tap position to be studied
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

After 1 h the top-oil temperature rise will be, see Equation (22).

$$\Delta\Theta_{TO} = (\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i})\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i} \tag{C.5}$$

where

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for t = 0, °C
τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

t is the duration of load, h

or rewritten:

$$\Delta\Theta_{TO} = \Delta\Theta_{TO,U}\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i}\, e^{-\frac{t}{\tau_{TO}}} \tag{C.6}$$

where

t is the duration of load, h
$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C
τ is the oil time constant of transformer, h
τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

When we substitute $\tau_{TO} = \tau_{TOR} = 3.5$, and the $\Delta\Theta_{TO,U}$ value of Equation (C.2), we obtain for $t = 1$ h.

$$\Delta\Theta_{TO} = (29.87K^2 + 6.13)\left(1 - e^{\frac{-1}{3.5}}\right) + \Delta\Theta_{TO,i}\, e^{\frac{-1}{3.5}} \tag{C.7}$$

where

K is the ratio of load L to rated load, per unit
$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C

or

$$\Delta\Theta_{TO} = 7.42K^2 + 1.53 + 0.75\Delta\Theta_{TO,i} \tag{C.8}$$

and for $t = 0.5$ h

$$\Delta\Theta_{TO} = 3.98K^2 + 0.82 + 0.87\Delta\Theta_{TO,i} \tag{C.9}$$

The winding hottest spot rise over top oil will be according to Equation (37).

$$\Delta\Theta_{TO} = \Delta\Theta_{H,R} K^{2m} = 28.6K^2 \tag{C.10}$$

where

K	is the ratio of load L to rated load, per unit
m	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See 1.
$\Delta\Theta_{H,R}$	is the winding hottest spot rise over top-oil temperature at rated load on the tap position to be studied, °C
$\Delta\Theta_{TO}$	is the top-oil rise over ambient temperature, °C

One quantity, the initial top-oil rise, is still missing and we will have to estimate it. If we assume the load cycle for normal load found in Table C.1, we may establish the rms value of the load curve, as an example, for the 6 h load preceding 6:00 a.m.

$$K = \sqrt{\frac{\left[(0.81)^2 + (0.68)^2 + (0.61)^2 + (0.58)^2 + (0.55)^2 + (0.53)^2\right]}{6}} = 0.634 \tag{C.11}$$

Using Equation (C.1), a load of this magnitude yields an ultimate top-oil rise of

$$\Delta\Theta_{TO,U} = 29.87K^2 + 6.13 = 29.87(0.634)^2 + 6.13 = 18.14^\circ C \tag{C.12}$$

Using $\Delta\Theta_{TO,i}$ = 18.14 °C at 6:00 a.m., and K = 0.52, we can determine $\Delta\Theta_{TO}$ at 7:00 a.m. as follows:

$$\Delta\Theta_{TO,U} = 7.42K^2 + 1.53 + 0.75\Delta\Theta_{TO,i} = 17.14^\circ C \tag{C.13}$$

where

K	is the ratio of load L to rated load, per unit
$\Delta\Theta_{TO,U}$	is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$	is the initial top-oil rise over ambient temperature for t = 0, °C

To determine the top-oil temperature rise at 8:00 a.m., set $\Delta\Theta_{TO,i} = \Delta\Theta_{TO}$ calculated at 7:00 a.m. Repeated application of Equation (C.8) will produce a top-oil temperature rise profile; however, a slight discrepancy occurs 24 h later at 6:00 a.m. When one continues to apply Equation (C.8), convergency to true values is soon obtained, as shown in normal load, $\Delta\Theta_{TO}$ columns of Table C.1. The first column represents the first iteration, and the second column represents the results after an additional iteration.

The winding hottest spot rise over top oil, $\Delta\Theta_{TO}$ is considered to be instantaneous. Only where current discontinuities occur will some consideration be given to the winding time-constant.

For example, at 6:00 a.m.:

$$\Delta\Theta_H = (28.6)(0.52)^2 = 7.73^\circ C \tag{C.14}$$

The equation, $\Theta_H = \Delta\Theta_{TO} + \Delta\Theta_H + \Theta_A$, will be used to establish the hottest spot winding temperature Θ_H, using for ambient temperature Θ_A = 30.0 °C.

A complete daily normal load cycle is shown in Table C.1 and plotted in Figure C.1.

C.3 Planned loading beyond nameplate (PLBN)

The constant on PLBN loading is hottest spot winding temperatures in the 120–130 °C range; therefore, $\Delta\Theta_{TO} + \Delta\Theta_{H} = 120\ °\text{C} - \Theta_{A} = 90\ °\text{C}$. The three highest temperatures for the normal loading cycle are just over 90.3 °C; therefore, $\Delta\Theta_{TO} + \Delta\Theta_{H} = 60.3\ °\text{C}$.

To estimate what load multiplier K should be to produce $\Delta\Theta_{TO} + \Delta\Theta_{H} = 90\ °\text{C}$, we proceed as follows:

$$\left[\frac{\left(K^{2}R+1\right)}{(R+1)}\right]^{n} = \frac{90}{60.3} \tag{C.15}$$

where

- K is the ratio of load L to rated load, per unit
- n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See 1.
- R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

and solving for K gives

$K = 1.26$

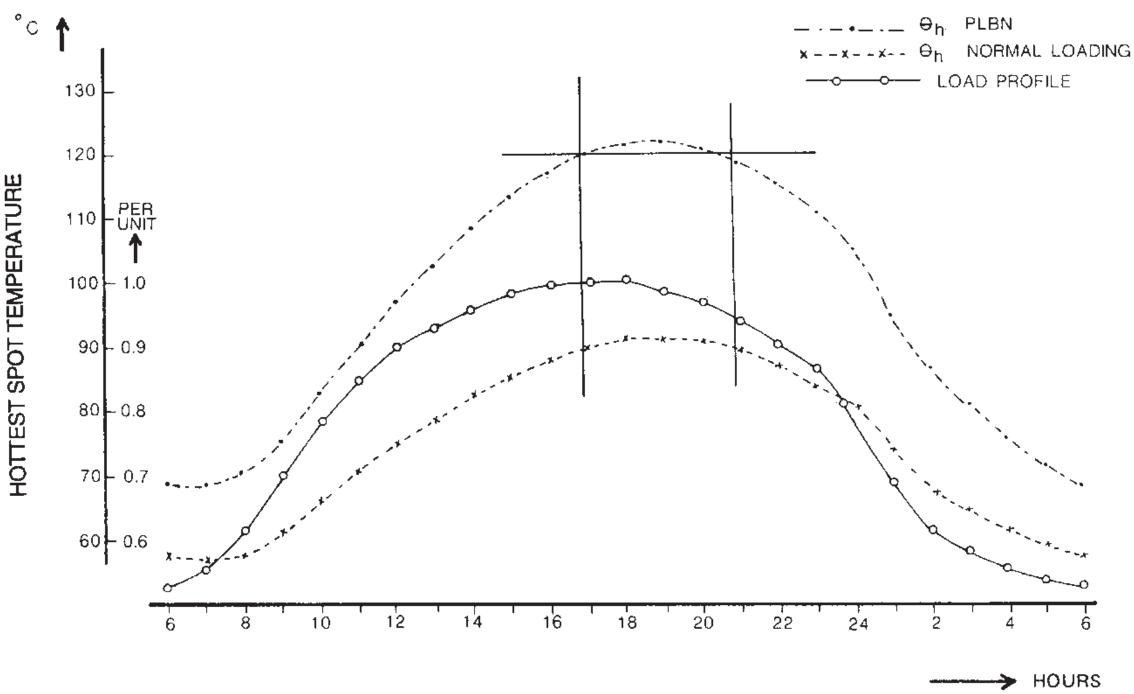


Figure C.1— Load cycles for normal loading and planned loading beyond nameplate

The top-oil rise is not quite proportional to the square of the load current (no-load losses are constant) but the winding gradient is proportional to the square of the load current. The multiplier may have to be corrected if it is unsatisfactory. Again we have to estimate an initial top-oil temperature. Following the same procedures as for the normal load, we obtain a temperature profile, based on the load cycle shown in Figure C.1. The hottest spot temperature is in the 120–130 °C range for close to 4 h.

C.4 Long-time emergency (LTE) loading

A user has to consider carefully the emergency loading conditions that may occur on his system. A maximum period of 6 h is used in our example. Assume that the long time emergency begins at 13:00 h, and was preceded by a PLBN loading. Suppose a load multiplier of value K_2 is applied.

At 13:00 h:

$\Delta\Theta_{TO,i}$ = 33.90 °C, which is equal to $\Delta\Theta_{TO}$ in the PLBN loading. Apply Equation (C.8) to find this value.

At 14:00 h:

$$\Delta\Theta_{TO} = \left(7.42 \times 0.93K_2^2\right) + 1.53 + \left(0.75 + 34.14\right) = 6.42K_2^2 + 27.14 \quad \text{(C.16)}$$

$$\Delta\Theta_H = \left(28.6 \times 0.96K_2^2\right) = 26.36K_2^2 \quad \text{(C.17)}$$

At 15:00 h:

$$\Delta\Theta_{TO} = \left(7.42 \times 0.96K_2^2\right) + 1.53 + \left(0.75\right)\left(6.42K_2^2 + 27.14\right) = 11.66K_2^2 + 21.89 \quad \text{(C.18)}$$

$$\Delta\Theta_H = 27.47K_2^2 \quad \text{(C.19)}$$

Repeated application of Equation (C.8) finally gives at 19:00 h an equation for $\Delta\Theta_{TO}$ and $\Delta\Theta_H$ in terms of K_2 as follows:

$$\Delta\Theta_{TO} = \Delta\Theta_H = 51.25K_2^2 + 11.11 \quad \text{(C.20)}$$

The LTE constraint is 140 °C, thus,

$$51.25K_2^2 + 11.11 + 30 = 140.0 \quad \text{(C.21)}$$

and

K_2 = 1.39

Table C.1 shows the top-oil rise and the winding gradient. At 13:00 h and at 19:00 h, there is a discontinuity in current. The winding time-constant usually is in the order of 3–5 min. After 20 min, ΔT_{HS} will be according to the new load. Figure C.2 shows the hottest spot temperature profile. The 140 °C temperature limitation has been met. The hottest spot temperature is in the 130–140 °C range less than 6 h and in the 120–130 °C range longer than 4 h, so a value of 1.39 applied to the per-unit load from 13:00–19:00 hours seems to be in order.

C.5 Short-time emergency (STE) loading

In our example, an STE loading is assumed to occur at 13:00 h, following a PLBN loading. After 1/2 h, the load is reduced to the LTE loading, which will persist for 5.5 h. We will use an interval load value K_3. The STE constraint is a maximum hottest spot temperature of 180 °C.

At 13:00 h:

$$\Delta\Theta_{TO,i} = 34.14^{\circ}C$$

Apply Equation (C.9) (for t = 0.5 h) to obtain at 13:30 h

$$\Delta\Theta_{TO} = 3.98K^2 + 0.82 + 0.87(34.14) \tag{C.22}$$

$$\Delta\Theta_H = 28.6K_3^2 \tag{C.23}$$

$$\Theta_H = \Delta\Theta_{TO} + \Delta\Theta_H + \Theta_A = 32.58K_3^2 + 30.52 + 30.0 + 180.0 \tag{C.24}$$

where

K_3	is the ratio of load L to rated load, per unit
Θ_A	is the average ambient temperature during the load cycle to be studied, °C
Θ_H	is the winding hottest spot temperature, °C
$\Delta\Theta_H$	is the winding hottest spot rise over top-oil temperature, °C
$\Delta\Theta_{TO}$	is the top-oil rise over ambient temperature, °C

K_3= 1.92

At 13:30 h: $\Delta\Theta_{TO}$ = 45.19 °C, $\Delta\Theta_H$ = 105.43 °C, Θ_H = 180.6 °C, load = 1.29 per unit

At 14:00 h: $\Delta\Theta_{TO}$ = (3.98) $(1.29)^2$ + 0.82 + (0.870) (45.19) =46.76 °C

Figure C.2 shows the temperature excursion to be within the limits for the STE loading. The hottest spot temperature will be somewhat longer in the 130–140 °C range limit.

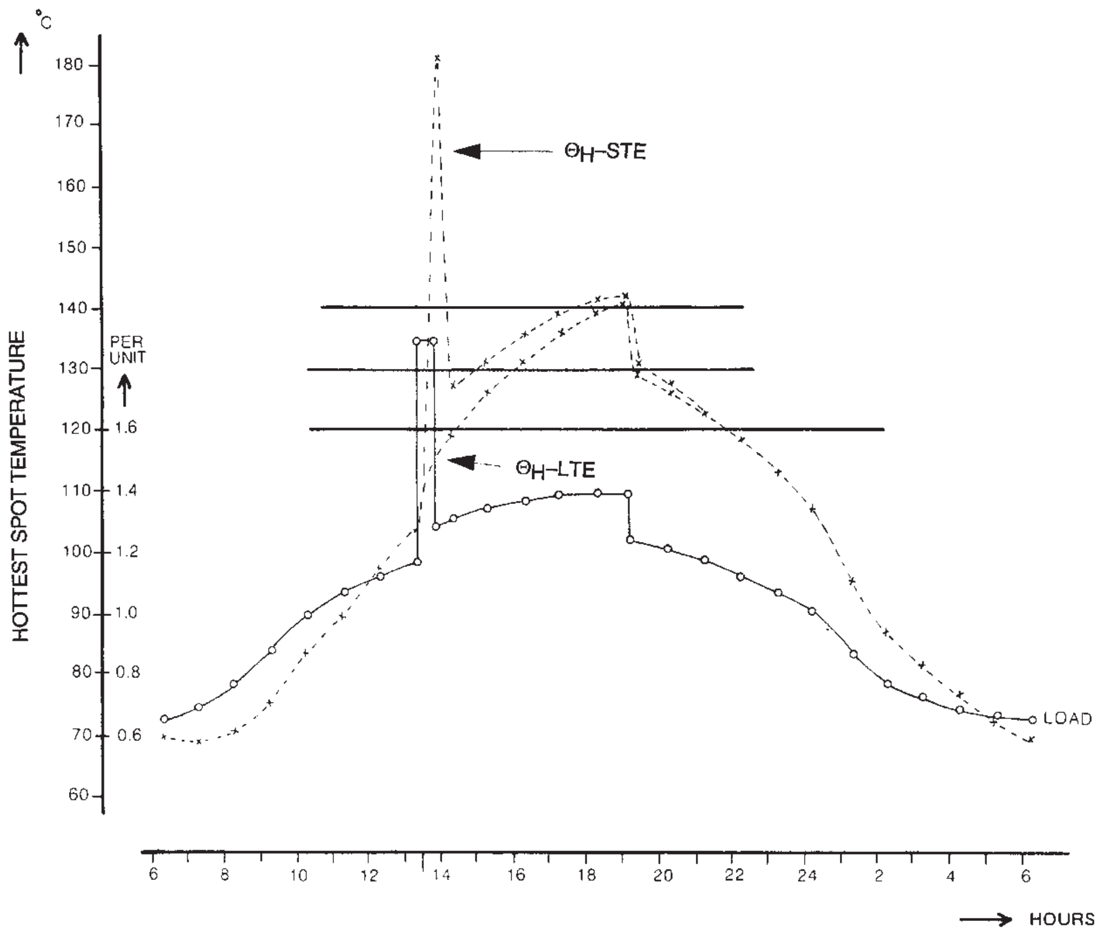


Figure C.2—Hottest spot temperature profile for long time and short time emergency loading

Annex D

(normative)

Philosophy of guide applicable to transformers with 55 °C average winding rise (65 °C hottest spot rise) insulation systems

D.1 General

Loading of transformers above nameplate is a controversial subject. Agreement on the loading limits can be agreed upon with the manufacturer if they have been clearly specified prior to the design of the transformer. However, since there has been new knowledge gained in recent years concerning stray flux fields and their effects of metallic temperatures, it is desirable to confirm greater than nameplate load capabilities with the manufacturers of transformers on critical systems.

Some users have considerable experience in loading power transformers above nameplate using computer programs in conjunction with IEEE Std C57.92-1981 and NEMA TR98-1978. Since this approach deals with loss of life due to the effects of thermal aging of the windings, it should always be accompanied with due consideration given to the load capabilities of all other components in the transformer. These components include bushings, tap-changers and terminal boards, current transformers, and leads. Relay settings should also be checked so that load is not dumped. Consideration should also be given to oil expansion and its effect on possible mechanical relief device operation, subsequent possible operation of the fault-pressure relay, and oil clogging of breathing devices. Forced-oil cooler fouling should also be a consideration when determining load capability. This fouling is particularly found in areas having salt spray environments or dust and chemical contaminants present. These computer programs should be modified to reflect this new loading guide where its use may lead to more conservative loading. The loss of a single transformer of over 100 MVA rating rarely causes power interruption of customers. However, loss of one transformer due to its failure or due to the failure of some other part in the electrical circuit can result in increased loading of the back-up transformers. Most utilities do not design for second contingencies without loss of load. The adverse consequences are therefore rather great if the increased loading of the back-up transformer results in a failure.

Common sense and good planning are required to keep the economic gains in balance with the risks of failure. Because excessive transformer temperatures weaken the insulation structures physically, and because many of the older transformers have low impedances, short-circuit failures should also be considered. The types of transformer construction are a factor in making this assessment. Most utilities load these transformers conservatively. Gas evolution in power transformers is not a new insulation contaminant. There are at least eight causes of gas within the transformer that have been documented. The risk of having a failure due to free gas in the insulating structure should take into consideration the insulation margins used and the construction of the insulation structures. The risk of failure increases considerably when the insulation levels are reduced three full steps from a typically accepted level such as use of 650 kV BIL on 230 kV transformers. The risk decreases when no insulation collars are used in highly stressed parts of these transformers with reduced BIL. Knowledgeable transformer engineers have paid close attention to gas evolution when specifying and designing these transformers.

The loading of transformers without thermally upgraded insulation (from an insulation aging point of view) can be considered to be similar to transformers with thermally upgraded insulation. The calculation of temperatures included in Clause 7 may be applied equally well for transformers without thermally upgraded insulation. Equation (3) in Clause 5 gives the equation to calculate equivalent aging and loss of life for transformers with 55 °C rise insulation systems. The normal loss of life ratings are loadings that result in a daily loss of life equal to that of a continuous winding hottest spot temperature of 95 °C for 55 °C rise transformers.

The factor that determines the greatest risk associated with loading transformers above nameplate rating is the evolution of free gas from the insulation of winding and lead conductors. This gas will result from the following two major sources:

a) *Vaporization of water contained in the insulation*. This process is discussed in Annex A of this guide.
b) *Thermal decomposition of cellulose*. Data on the constituent gases and their proportions released by thermal decomposition of both thermally up-graded and non-upgraded cellulose insulation may be found in many of the references in the bibliographies for Annex A and Annex I.

D.2 Aging equations

For older transformers with 55 °C average winding rise insulation systems with a rated hottest spot rise over ambient of 65 °C and a 30 °C ambient, the reference temperature is 95 °C. The equations for per-unit life and the aging acceleration factor are as follows:

$$\text{Per unit life} = 2.00 \times 10^{-10} e^{\left[\frac{15000}{\Theta_H + 273}\right]} \tag{D.1}$$

where

Θ_H is the winding hottest spot temperature, °C

$$F_{AA} = e^{\left[\frac{15000}{368} - \frac{15000}{\Theta_H + 273}\right]} \tag{D.2}$$

where

F_{AA} is the aging acceleration factor
Θ_H is the winding hottest spot temperature, °C

Annex E

(normative)

Unusual temperature and altitude conditions

E.1 Unusual temperatures and altitude

Transformers may be applied at higher ambient temperatures or at higher altitudes than specified in IEEE Std C57.12.00, but performance may be affected, and special consideration should be given to these applications.

E.2 Effect of altitude on temperature rise

The effect of the decreased air density due to high altitude is to increase the temperature rise of transformers since they are dependent upon air for the dissipation of heat losses.

E.3 Operation at rated kVA

Transformers may be operated at rated kVA at altitudes greater than 1000 m (3300 ft) without exceeding temperature limits, provided the average temperature of the cooling air does not exceed the values of Table E.1 for the respective altitudes.

a) See 4.3.2 and Table 1 in IEEE Std C57.12.00-2010 for corrections of transformer insulation capability at altitudes above 1000 m (3300 ft).
b) Operation in low ambient temperature with the top liquid at a temperature lower than –20 °C may reduce dielectric strength between internal energized components below design levels.

E.4 Operation at less than rated kVA

Transformers may be operated at altitudes greater than 1000 m (3300 ft) without exceeding temperature limits, provided the load to be carried is reduced below rating by the percentages given in Table E.2 for each 100 m (330 ft) and that the altitude is above 1000 m (3300 ft).

Table E.1—Maximum allowable average temperature[a] of cooling air for carrying rated kVA

Method of cooling apparatus	1000 m (3300 ft)	2000 m (6600 ft)	3000 m (9900 ft)	4000 m (13200 ft)
Liquid-immersed self-cooled	30	28	25	23
Liquid-immersed forced-air-cooled	30	26	23	20
Liquid-immersed forced-oil-cooled with oil-to-air cooler	30	26	23	20

[a] It is recommended that the average temperature of the cooling air be calculated by averaging 24 consecutive hourly readings. When the outdoor air is the cooling medium, the average of the maximum and minimum daily temperatures may be used. The value obtained in this manner is usually slightly higher by not more than 0.3 °C than the true daily average.

Table E.2—Rated kVA correction factors for altitudes greater than 1000 m (3300 ft)

Types of cooling	Derating factor% per 100m (330 ft)
Liquid-immersed air-cooled	0.4
Liquid-immersed water-cooled	0.0
Liquid-immersed forced-air-cooled	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-air cooler	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-water-cooler	0.0

Annex F

(normative)

Cold-load pickup (CLPU)

F.1 General

Cold-load pickup (CLPU) is the loading imposed on power and distribution transformers upon re-energization following a system outage. When an outage occurs, temperature in residential and office buildings starts to decay towards the outdoor ambient temperature. The amount of this decay and heat loss depends upon the temperature differential, the building insulation level, etc. Diversity among all the electric space heating furnaces and other appliances is rapidly lost. When the power is restored, all connected electric space heating furnaces, heaters, and other appliances will demand power simultaneously until the normal temperature conditions are attained and the diversity is regained. The time required to regain the diversity depends on the heating capacity of the furnaces and the duration of the preceding outage.

Obviously, the total loading imposed on the transformer after power restoration will be substantially higher than its normal peak load. Cold-load pickup consists of the following two components of the restoration load:

a) Inrush current associated with transformers, motor starting, etc. Although the magnitudes are quite large (in the order of 6 to 25 times the normal current), the duration is quite short, lasting a few cycles.
b) Load due to loss of diversity among thermostatically controlled cycling appliances. This load may persist for tens of minutes.

F.2 Duration of loads

Duration of this excessive load depends upon several variables, some of which are as follows:

- Time of and the day the outage begins – Day of the week outage ends
- Duration of outage
- Temperature conditions and wind
- Number of customers affected by the outage – Building size and insulation levels
- Type of load

This loading condition will persist until all the thermostatically controlled appliances are satisfied and the diversity has been restored. Typically, the maximum length of time during an outage until all diversity will be lost is around 20 min. The longer the outage lasts, the longer the load will remain undiversified after re-energization.

F.3 CLPU ratio

The ratio of the post-interruption load to pre-interruption load varies with the length and time of day of the interruption and the ambient temperature during interruption.

As an example, CLPU ratios that may be expected in a utility are as follows:

Load type	CLPU ratio
Major industrial	Less than 1.0
Residential plus 50% industrial	1–1.5
Urban residential plus less than 20% penetration of electric	1.5–2.0
Combination urban and rural	2.0–2.5
Rural	2.5–3.0

Different users will have different CLPU ratios depending upon their own customers and operating practices. Each user should look at the ratios for his or her system.

Studies [B49], [B50], [B51] have shown that CLPU with high penetration of electric heating can become a limiting factor for substation transformers and for the protective equipment on the feeder. Electric heat penetration of 50–70% could lead to a CLPU ratio in the range of 3–4, or even higher.

Air conditioning could become a limiting factor if the penetration of air conditioning loads exceeds electric resistance space heating by a factor of 3 or more.

Depending upon normal loading of the transformer, it is possible to reach short-term emergency loading limits of the substation transformer. In some cases, it is possible for CLPU to exceed the thermal limits of a transformer resulting in associated loss of transformer insulation life.

During these types of loads, the auxiliary cooling equipment should be in operation. Since the duration of these loads is short or does not occur often, it is recommended that CLPU be considered as short-time emergency loading of the transformer.

F.4 Other considerations

Although CLPU has not been recognized as a serious problem in the past, changing patterns of oil and gas price and availability in several parts of the country have resulted in a continuing changeover from oil-based heating system to electric space heating system, making CLPU a more serious problem. In the substations where the transformers may be approaching their nameplate loading, it is worthwhile investigating the type of loads served to determine if a CLPU problem exists.

Depending upon circumstances, it may be necessary to restore the load in stages.

The effect of CLPU should be considered in the setting of relays, recloser trip settings, and fuse sizes to reduce nuisance tripping.

When planning capacity additions, utilities normally select the transformer capabilities to accommodate the anticipated load growth. It is recommended that effects of CLPU should also be considered during this planning. Application of loads in excess of nameplate when ambient temperatures are less than 0 °C requires consideration of transformer design, cooling control, and prior loading. Viscosity of the insulation fluid will influence velocity and distribution, and may detrimentally affect heat transfer. For power transformers with external cooling accessories, the method of control should be reviewed to help ensure oil flow is induced before loading exceeds the respective ratings. If prior loading cannot be controlled by demand or rate of increase, the windings may experience localized hottest spots and accelerated aging of conductor insulation during cold weather ambients.

Annex G

(normative)

Open-Source Code

G.1 General

The fundamental problem the loading guide is trying to solve is to quantify thermal aging of insulation based on loading conditions and how that may impact the usable life of the transformer. A reasonable model to calculate the temperature in the weakest spot, or thermally speaking the 'hottest' spot is needed.

The model described previously in Clause 7 is complex given the system differential equations intertwined with different modelled locations. Since differential equations do not have exact solutions (unless an analytical solution is found or approximated) results may vary depending on how the equations are solved (Euler, Runge-Kutta, etc.). Setting an ever-decreasing time step may not respond rapidly enough to the behavior of the system of equations. This is also why the equations of the previous Annex G were re-written to differential form, so that they would allow any number of ways for solving them. There are also subtle issues where imaginary numbers may result from the equations as they were originally defined.

To enable engineering users to have a workable steppingstone, an open-source code was developed. In the 2011 version of guide, the source code for a BASIC implementation was printed with the guide. Since then, the IEEE Standards Association created an open-source code repository for its various activities which offers a modern way of storing and tracking source code. We therefore developed an implementation of the equations in Clause 7 of this guide in Python and provide the code in the IEEE open-source repository [B52].

While the model in Clause 7 is considered normative, the open-source code is considered informative. For instance, there is no reason why the model could also not be adequately developed in C++ or any other language. Therefore, the open-source code itself is not required to follow this guide. The purpose is for users to have some usable comparison point for implementation or to calculate model temperatures for their own projects. Furthermore, providing open-source code allows fix of unforeseen software `bugs' and to make improvements for usability or edge cases after the publication of this guide.

The IEEE C57.91 Thermal Models open-source code project site provides instructions on how to execute the code, example input files, and a basic user interface can be found there. For exact details, please read the documentation in that repository as it will be the most up-to date.

G.2 Code Examples

The code was validated on a few transformer heat-run datasets during the this revision. The previous 2011 version of this guide had one example case to show how the Basic code was implemented. Figure G.2, provides a direct comparison between the values obtained with the previous BASIC code and the new Python open-source code referenced in this guide. Table G.1 shows the tabulated values form the new and old code for validation purposes and the transformer thermal properties are described in Table G.2.

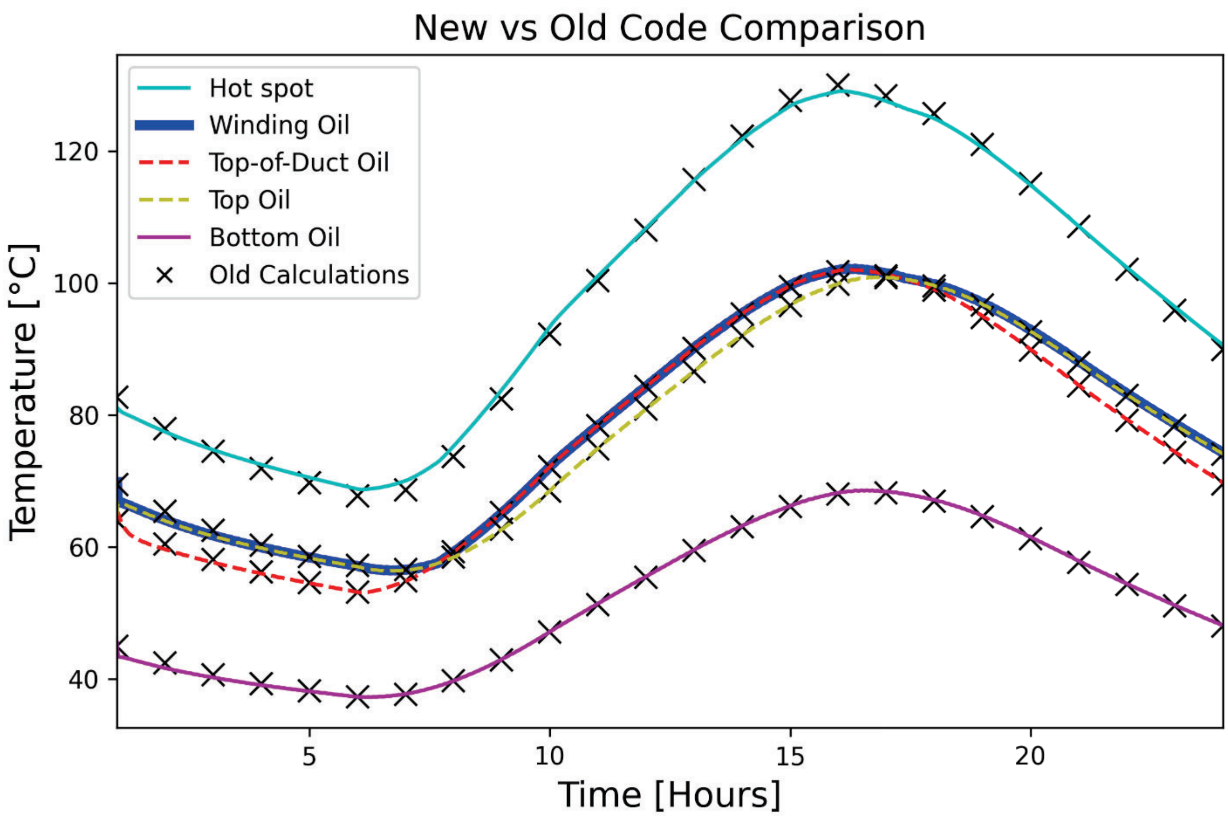


Figure G.1—Comparison of previous BASIC code of the older Annex G

In Figure G.1, ‘X’ denotes hourly model points reported from the BASIC code, while the solid lines show the minute-by-minute resolution from the new open-source Python model for each of the temperature points shown. The fact that they show good agreement suggests the open-source code is consistent with the previous version. It can also be seen that the winding oil follows either the ‘Top oil’ or the ‘Top-of-duct oil’, whichever is larger. However, large departures from each other may become evident under certain model parameters.

Table G.1—Comparison of previous BASIC code of the older Annex G Tabular Form

Time [Minutes]	Load [PUL]	Ambient [C]	Duct Liquid [C]	Duct Liquid [C] (Old)	Hot Spot [C]	Hot Spot [C] (Old)	Average [C]	Top Liquid [C]	Top Liquid [C] (Old)	Bottom Liquid [C]	Bottom Liquid [C] (Old)	Winding [C]	Winding Liquid [C]	PUL	F_aa	F_eqa	Est. % Loss of Life
60	0.6	29.5	64.8	64	80.8	82.7	55.1	65	69.5	45.2	45	69.8	69.5	25	0	0	0
120	0.6	29.2	59.6	60.5	77.4	77.9	52.8	63.9	65.4	41.6	42.4	62.1	64.1	37.5	0	0	0
180	0.6	29	57.6	58.1	74.7	74.5	50.9	61.6	62.5	40.2	40.6	60	61.7	52.3	0	0	0
240	0.6	28.7	56	56.2	72.5	71.9	49.5	59.9	60.3	39.1	39.3	58.1	59.9	68.9	0	0	0
300	0.6	28.5	54.6	54.6	70.6	69.7	48.2	58.4	58.6	38.1	38.2	56.5	58.4	88	0	0	0
360	0.6	28.2	53.2	53.2	68.8	67.8	47.2	57	57.2	37.3	37.3	55	57.1	110	0	0	0
420	0.6	29.8	54.8	54.9	70	68.7	47.1	56.5	56.6	37.7	37.7	57.2	56.6	93.9	0	0	0
480	0.7	31.8	59.2	59.3	75.3	73.7	49.1	58.5	58.5	39.7	39.7	62.7	59.2	48.8	0	0	0
540	0.8	33.9	65.1	65.2	83.7	82.4	52.8	62.6	62.7	42.9	42.9	69.8	65.1	17.6	0.1	0	0
600	0.9	35.9	72	72.2	93.2	92.3	57.8	68.4	68.5	47.1	47.1	78	72.1	5.9	0.2	0	0
660	0.9	37.1	78.4	78.4	101.1	100.4	63.2	75	74.9	51.5	51.3	85.2	78.5	2.5	0.4	0.1	0
720	1	38.4	84.3	84.3	108.3	108	68.2	80.9	80.9	55.5	55.4	91.7	84.3	1.2	0.8	0.1	0
780	1	39.6	90.1	90.1	115.5	115.7	73.1	86.6	86.6	59.5	59.5	98.3	90.1	0.6	1.7	0.2	0
840	1.1	40	95.3	95.3	121.7	122.3	77.6	92	92	63.1	63.1	104.1	95.3	0.3	3.2	0.3	0
900	1.1	40	99.6	99.5	126.9	127.7	81.5	96.7	96.6	66.3	66.1	108.9	99.7	0.2	5.2	0.6	0
960	1.1	39.6	101.9	101.7	129	130	84.1	99.9	99.8	68.2	68	111	102	0.2	6.4	0.9	0
1020	1.1	38.2	101.4	101.1	127.6	128.4	84.6	100.9	100.8	68.4	68.2	109.9	101.5	0.2	5.6	1.2	0
1080	1	36.8	99.1	98.9	125	125.7	83.4	99.7	99.6	67.2	66.9	107.2	99.8	0.2	4.4	1.4	0
1140	1	35.4	94.9	94.8	120.5	121	80.7	96.7	96.7	64.8	64.6	102.3	97	0.3	2.8	1.6	0
1200	0.9	33.9	89.9	89.8	114.8	115.1	77.1	92.6	92.6	61.5	61.3	96.5	92.9	0.6	1.6	1.6	0
1260	0.9	32.5	84.5	84.4	108.6	108.6	72.9	88	87.9	57.9	57.7	90.4	88.2	1.1	0.9	1.6	0
1320	0.8	31.7	79.3	79.2	102.3	102.1	68.7	83	83	54.4	54.3	84.4	83.2	2.2	0.4	1.5	0
1380	0.8	30.8	74.4	74.3	96.3	95.9	64.8	78.5	78.4	51.1	51.1	78.8	78.6	4.2	0.2	1.5	0
1440	0.7	30	69.8	69.6	90.6	89.9	61.1	74.1	74.1	48.1	48	73.6	74.3	7.9	0.1	1.4	0

Table G.2—Example Transformer Thermal Properties

Rated MVA	52.267
MVA Rated Losses Measured	28
Temperature Losses Measured	75
Winding Losses	51690
Eddy Current Losses	0
Stray Losses	21078
Core Losses	36986
Energy of Hotspot	1
Mass of Core and Coils	75600
Mass of Tank	31400
Liquid Volume	4910
Ambient Rated Temperature	30
Winding Guaranteed Rated Temperature	65
Rated Winding Temperature	63
Rated Hotspot Temperature	80
Rated Top Oil Temperature	55
Rated Bottom Oil Temperature	25
Height of Hotspot	1
Tau (Winding Timing Constant)	5
Cooling System	ONAF
Winding Material	Copper
Liquid Type	Mineral Oil

G.3 Variation in Model Performance

There may be instances where the previous version of Clause 7 from C57.91-2011 and the current Clause 7 disagree.

The first major difference stems from whether certain parameters are known, for example the rated bottom oil temperature rise. The current Clause 7 allows for an alternative method which does not require the bottom oil rated temperature. It is a simplification of the main model posed in Clause 7 following a series of assumptions. Clause 7 of 2011 was found to be mathematically identical to the current alternative Clause 7 model (see Appendix K of this guide). With the bottom oil rated temperature included, a more accurate calculation of the hotspot and top oil temperature can be calculated that will differ from previous calculations using the Clause 7 from C57.91-2011 which did not take this temperature into account.

The second major difference is writing the equations from the old Annex G in C57.91-2011 as true differential equations for the current Clause 7. The previous Annex G (and therefore also the previous model equations written by Pierce [B61, B62]) were written in a form of small finite differences in time, often called the Euler method. This makes the equations solvable as an exact definition but is an incorrect representation of the underlying model. The equations, as written, assumed that the only way to solve the differential equations is by using the Euler method, when in fact there are other, more accurate ways of solving differential equations. By writing the underlying model in its purest form of differential equations, it allows the underlying model to be solved in any number of ways. A common way of solving differential equations in physics is to use a Runge-Kutta method. In brief summary, Runge-Kutta methods calculate higher order differentials (think “acceleration” of the equations) over small step sizes to get a better approximation of the solution to the equations instead of just using small step size in time. Again, differential equations do not have exact solutions unless they are simplified to an equation with a known analytical solution. For this reason, the open-source code employs the Runge-Kutta method to solve the set of differential equations and may result in different values compared to being solved using the Euler method, as it had been done in the past. It does, however, provide for other options of solving the equations for comparison and to better fine tune the model.

G.4 Disclaimer

This computer program is an essential part of IEEE Std C57.91-202x. This computer program may be copied, sold, or included with software that is sold as long as Annex G of IEEE Std C57.91-202x is cited as the source. This computer program may be used to implement this standard and may be distributed in source code or compiled form in any manner. This file may be copied for individual use by users who have purchased this standard.

The IEEE disclaims any responsibility or liability for damages resulting from misinterpretation or misuse of said information by the user.

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Annex H

(normative)

Operation with part or all the cooling out of service

H.1 General

Where auxiliary equipment, such as pumps or fans, or both, is used to increase the cooling efficiency, the transformer may be required to operate for some time without this equipment functioning. The permissible loading under such conditions is given in the following clauses.

H.2 ONAN/ONAF transformers

Some manufactures use many small fans and others use a small number of large fans. If the number of fans inoperative is a large percentage of the total, use the self-cooled (ONAN) rating. For some designs only one or two inoperative fans may result in loss of significant cooling capacity.

H.3 ONAN/ONAF/ONAF, ONAN/ONAF/OFAF, and ONAN/OFAF/OFAF transformers

For triple rated forced-air, forced-oil-cooled transformers with all or part of the cooling inoperative use the nameplate rating based on the full stage of cooling remaining in operation, or if less than a full stage of fan and pump cooling is operative, use the self-cooled (ONAN) rating. For loss of either fans or pumps on a stage of cooling, use the rating that pertains to total loss of that stage of cooling. For large units with many fans, the loss of one or two fans will result in minimal temperature increase. For non-directed OFAF units, the loss of one or more pumps with the fans still in operation results in an increase in tank top oil, which gives increased temperatures for bushings, cables, and other ancillary components; however, the increase in winding hottest spot rise may not be significant.

H.4 OFAF and OFWF transformers

H.4.1 General

In general, the heat exchangers used to cool OFAF and OFWF type transformers will dissipate only an insignificant amount of heat when either the forced-oil circulation or the forced cooling medium (air or water) are inoperative. If only part of the coolers is inoperative, then refer to H.5 for load capability. If all the coolers are inoperative, loading amounts and durations can be calculated as in H.4.2.

The amount of load carried, the duration of the load, the previous loading condition, the ambient temperature, and the physical parameters of the transformer determine its hottest spot temperature and the loss-of-life experienced during the period of loss of all cooling. The user should calculate in accordance with the method below and refer to other pertinent clauses of this guide to determine the effects of the operating condition. During the period of loss of all cooling, the only significant amount of heat dissipated by the transformer will depend on tank radiation and its convection characteristics, which, in turn, are dependent on tank dimensions. Heat dissipation characteristics may be calculated from measurements obtained by measuring the actual unit or from estimations based on the transformer outline drawings.

H.4.2 Calculations

An approximation of the effect of loading and time upon the oil and hottest spot temperature can be determined as shown in this clause. More accurate data may be obtained from the manufacturer.

H.4.2.1 Equations

1) Estimate the losses in watts that will be dissipated by the tank at the 100% OFAF oil rise after loss of all cooling as follows:

$$q_{TANK} = (0.00365)(0.155 \times S)(\Delta\Theta_{AO,R})^{1.21} \tag{H.1}$$

where

q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$, W
S is the sum of surface areas of tank walls and cover neglecting braces, appurtenances, etc., cm^2
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C

2) Estimate the ultimate rise of average oil for the load that is to be maintained as follows:

$$\Delta\Theta_{AO,U} = \left(\frac{P_T}{q_{TANK}}\right)^{0.8} \Delta\Theta_{AO,R} \tag{H.2}$$

where

P_T is the total losses in watts, at load to be maintained
q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$, W
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{AO,U}$ is the ultimate rise of average oil over ambient, °C

3) The time constant corresponding to this loading condition should be calculated as follows:

$$\tau_L = \frac{C\left[\Delta\Theta_{AO,U} - \Delta\Theta_{AO,R}\right]}{P_T - q_{TANK}} \tag{H.3}$$

where

C is the thermal capacity as defined in Equation (30) or Equation (31)
P_T is the total losses in watts, at load to be maintained
q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{AO,U}$ is the ultimate rise of average oil over ambient, °C
τ_L is the oil time constant corresponding to loading condition, h

4) The average oil rise at any time *t* for the transformer in this operating mode can be estimated from the following formula:

$$\Delta\Theta_{AO} = \left(\Delta\Theta_{AO,U} - \Delta\Theta_{AO,R}\right)\left(1 - e^{\frac{-t}{\tau_L}}\right) + \Delta\Theta_{AO,R} \tag{H.4}$$

where

t	is the time, h
$\Delta\Theta_{AO}$	is the average oil rise over ambient at time *t*, °C
$\Delta\Theta_{AO,R}$	is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{AO,U}$	is the ultimate rise of average oil over ambient, °C
τ_L	is the oil time constant corresponding to loading condition, h

5) During the time period of t/τ_L = 0 to 0.15, the difference between top-oil temperature and average oil temperature can be estimated as follows:

$$\Delta\Theta_{TO-AO} = 7t + 6 \tag{H.5}$$

where

t	is the time, h
$\Delta\Theta_{TO\text{-}AO}$	is the difference in top oil temperature and average oil temperature, °C

The estimated top-oil rise can then be determined as follows:

$$\Delta\Theta_{TO} = \Delta\Theta_{TO-AO} + \Delta\Theta_{AO} \tag{H.6}$$

where

$\Delta\Theta_{AO}$	is the average oil rise over ambient at time *t*, °C
$\Delta\Theta_{TO}$	is the top-oil temperature rise over ambient, °C
$\Delta\Theta_{TO\text{-}AO}$	is the difference in top oil temperature and average oil temperature, °C

It is recommended that $\Delta\Theta_{TO} + \Theta_A$ not exceed 110 °C.

Estimates of top-oil rises at t/τ_L greater than 0.15 will have to be obtained from the manufacturer.

The hottest spot rise above top-oil temperature, for directed oil flow units, will increase substantially when the forced-oil flow is stopped. An estimate of this rise can be obtained from the manufacturer. On the premise that some reasonable oil circulation will continue by natural convection, a rough estimate can be made as shown in the paragraphs that follow.

For nondirected flow, OFAF:

$$\Delta\Theta_{H,R} = \left(\Delta\Theta_{W/A} - \Delta\Theta_{AO,R}\right) + 5 \tag{H.7}$$

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{H,R}$ is the hottest spot conductor rise over top-oil temperature at rated load, °C
$\Delta\Theta_{W/A}$ is the average winding temperature rise over ambient, °C

For directed flow, ODAF:

$$\Delta\Theta_{H,R} = 2.0\left(\Delta\Theta_{W/A} - \Delta\Theta_{AO,R}\right) + 5 \tag{H.8}$$

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{H,R}$ is the hottest spot conductor rise over top-oil temperature at rated load
$\Delta\Theta_{W/A}$ is the average winding temperature rise over ambient, °C

And then,

$$\Delta\Theta_{H} = \Delta\Theta_{H,R} K^{2m} \tag{H.9}$$

where

K is the ratio of load to be carried to 100% OFAF nameplate rating
m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See 1.
$\Delta\Theta_{H}$ is the hottest spot rise above top-oil rise at load to be maintained, °C
$\Delta\Theta_{H,R}$ is the hottest spot conductor rise over top-oil temperature at rated load, °C

The average winding rise and average oil rise should be obtained from the certified test reports for the maximum nameplate rating.

The hottest spot temperature at the load to be maintained can be estimated as follows:

$$\Theta_{H} = \Theta_{A} + \Delta\Theta_{TO}\Delta\Theta_{H} \tag{H.10}$$

where

Θ_{A} is the ambient temperature, °C
Θ_{H} is the hottest spot temperature, °C
$\Delta\Theta_{H}$ is the hottest spot rise above top-oil rise at load to be maintained, °C
$\Delta\Theta_{TO}$ is the top-oil temperature rise over ambient, °C

It is recommended that Θ_H not exceed 140 °C.

H.4.3 Caution

In using the equations in H.4.2.1, the following factors should be considered during a loss of cooling situation as follows:

a) Much of the normal overload protection (overcurrent relay, etc.) installed on a transformer will be inadequate for this operating condition.

b) The hottest spot relay (for alarm and in many cases trip), using the two input parameters of phase current and top-oil temperature, is calibrated to a hottest spot rise over oil with forced-oil circulation in the windings. It will indicate a temperature many degrees lower than actual hottest spot temperature if there is no forced oil flow in the windings.

1. If the transformer is of directed flow design and pumps have been lost, it may be necessary to hold top-oil temperature well below normal to keep the hottest spot temperature within its limitation, since, with drastically reduced oil flow, the hottest spot gradient is greatly increased. Hence, the top-oil temperatures should be kept lower to stay within the design hottest spot limitation.

H.5 Forced-oil-cooled transformers with part of coolers in operation

For forced-oil-cooled (OFAF or OFWF) transformer ratings, with part of the coolers in operation, use the reductions in permissible loading given in Table H.1. These permissible loads will give approximately the same temperature rise as full load with all cooling in operation.

Table H.1—Loading capability for OFAF or OFWF transformers

% of total coolers in operation	Permissible load in % of nameplate rating
100	100
80	90
60	78
50	70
40	60
33	50

Annex I

(informative)

Transformer insulation life

I.1 Historical perspectives

In past versions of the guides for loading transformers, much space was dedicated to the subject of "loss-of-life." The background of this term was not always well understood. Many engineers assumed incorrectly that the "life" in "loss-of-life" referred to the transformer's life. From the beginning, the important modifier "insulation" frequently has been omitted from the phrase, "loss-of-life." Actually, loss-of-life has always meant "loss-of-insulation life." Because this distinction is so important, the user should review the following discussion of the history of loss-of-insulation life.

In the 1920s, but reported in 1930, Montsinger [B53] placed varnished cambric tape insulation into a series of oil-filled test tubes, heated them, and then measured the insulation's tensile strength. He reported that the life of the varnished cambric was reduced by one half for each 8 °C increase in continuous temperature. The "end-of-life" was defined as the point where the tensile strength of the varnished cambric reached 50% of its initial value. The loss of 50% of initial tensile strength end point was probably chosen because tensile strength was easy to measure. It also varied in about the same manner as other mechanical properties of the early insulations. This is not true of many of the insulating coatings, etc., in common use today. This was an initial signal for engineers to use their slide rules (later calculators and now computers) to make calculations of the expected life of a transformer's insulation at various operating temperatures to many significant figures beyond the accuracy of the input data.

The end-of-life of a transformer is not determined by a 50% reduction in the tensile strength of its insulation. It has been obvious for some time that transformers with residual insulation tensile strengths well below 20% of initial operate in a completely satisfactory manner. Lamentably, the industry gave far too much credence to Montsinger's test tube work. In 1944, Montsinger [B54] stated that one should not use aging data at higher temperatures and that the 8 °C rule was incorrect for lower temperatures. He also said, "There is, of course, some question whether laboratory aging tests made on isolated strips of paper in sealed tubes can be applied directly in estimating the life of insulation in a transformer." Unfortunately, the transformer industry apparently has seemed to ignore this statement.

Later, Dakin [B55] postulated that transformer insulation deteriorated following a modification of Arrhenius' chemical reaction rate theory. Dakin was probably correct, and a simple "insulation" life curve was developed to relate the insulation's life at a test temperature to an operating temperature. The industry took Dakin's work and, unfortunately, Montsinger's residual tensile strength end-of-insulation life end point and arrived at loss-of-life percentages (without the insulation modifier) based on time at various temperatures. These percentages were badly flawed due to the poorly selected end point; yet, with some slight modifications, they still appeared in recent loading guides without that all-important "insulation" modifier. This happened in spite of a contemporary 1944 paper by Satterlee and Reed [B56] whose tests showed that insulation, in a sealed tank of oil with no load but exposed to ambient temperatures only, experienced a reduction of tensile strength to 20% of initial in about 2.5 years.

The data on the loss-of-insulation life curves shown in the different guides differed considerably. For example, although both distribution and power transformers use the same insulation, the loss-of-insulation life curves in the guides show a considerable variation for a specific temperature. The insulation life of distribution transformers is listed as being several times greater than the power transformer's guide insulation life.

In summary, loss-of-life data in previous guides was based, in part, on observations made 60–70 years ago, on obsolete materials, test tube data, and an inferior refined oil. In addition, the original investigator repudiated the data in the 1940s.

In the mid-1950s, a task force of the AIEE Transformers Committee composed of the manufacturers and users of distribution and power transformers undertook the most comprehensive examination of transformer life to date. Sample distribution transformers of each manufacture were subjected to a series of carefully selected loading tests at a number of different manufacturing locations. The data from each of the investigators was coded to preserve the supplier's identity and sent to a neutral data compiler for review by the task force. It was initially planned by the task force to subject the transformer test models to alternate back-to-back loading and cooling cycles at three carefully determined hottest spot conductor temperatures to determine their straight line life characteristic in accordance with reaction rate theory. The temperatures selected were 220 °C, 180 °C, and 140 °C. The test duration at each temperature was determined by current theory. The temperature was controlled by a monitor of exactly the same design containing thermocouples located throughout the windings and tank. After thermal cycling, each test model received "product" tests; the monitor received no product tests except oil analysis. The test end point was established as failure during any one of the product tests.

The 220 °C models were aged first to obtain a better estimate of the test duration for subsequent temperatures. To the surprise of many task force members, the 220 °C models survived many more cycles than expected. The variability between manufacturers was quite large as expected. The next series at 180 °C hottest spot temperature was started at lengthened test duration and sure enough, the models continued to pass test cycle after cycle beyond expectation. Using end point times from the very first 180 °C failures to be reported, the task force predicted both an unacceptably long test cycle for the 140 °C models and a projected standard "life" exceeding hundreds of thousands of hours at normal rated temperature. Many manufacturers discontinued the 180 °C cycles. Others continued to run the tests for their own purposes. Although the end point tests included impulse and low-frequency withstands and short-circuit and visual examination, many of the investigators reported short circuits particularly in the end turns as the ultimate failure mode. Investigation showed this to be true long after nearly total dielectric strength reduction of the insulating system.

Since at least three test temperatures were not obtained from which to extrapolate the life characteristics of the tested systems; and as the "end-of-life" points reached at the 220 °C and 180 °C aging temperatures were significantly longer than anticipated, the task force, after much discussion, arbitrarily redefined the life curve for distribution transformers and supported the subsequent recommendation of the even more conservative power transformer life line.

A careful review of this history has been coupled with recent findings based on work done on model power transformers on two extensive EPRI transformer loading research projects [B57], [B58]. Some results of this review have been as follows:

a) The reviewers have decided that the insulation life curves for distribution and power transformers are similar.
b) The insulation life curves for distribution and for power transformers, which were found in their respective previous guides, are not appropriate for modern transformer loading guides, but should be included in a future revision of IEEE Std C57.100 for thermal evaluation comparisons of the new insulation system.
c) The chemical test measurement of degree of polymerization (DP) is a much better indication of cellulosic insulation mechanical characteristics than loss of tensile strength.

I.2 Thermal aging principles

The principal constituent of most transformer conductor insulation materials is cellulose, an organic compound whose molecule is made up of a long chain of glucose rings or monomers (Fabre and Pinchon [B59], Shroff and Stannet [B60], Lampe and Spicar [B61], Beavers, Rabb, and Leslie [B62]. Degree of molecular polymerization refers to the average number of glucose rings in the molecule and it typically ranges from 1000–1400 for new material. A single cellulose fiber will contain many of these long chains and the mechanical strength of the fiber, and hence of its parent material, is closely related to the length of the chains. Thus, the degree of polymerization is a good measure of retained strength and functionality of cellulose.

As cellulose ages thermally in an operating transformer, three mechanisms contribute to its degradation, namely hydrolysis, oxidation, and pyrolysis (Shroff and Stannet [B60], Lampe and Spicar [B61]). The agents responsible for the respective mechanisms are water, oxygen, and heat. Each of these agents will have an effect on degradation rate so they must be individually controlled. Water and oxygen content of the insulation can be controlled by the transformer oil preservation system, but control of heat is left to transformer operating personnel.

Since the early days of transformer manufacture, the deterioration of mechanical properties as a result of thermal aging has been recognized. Montsinger [B54] published early aging data and made an observation about the aging rate that has been widely used. He noted that the rate of deterioration of mechanical properties doubled for each 5–10 °C increase in temperature. The doubling factor was not a constant, being about 6 °C in the temperature range from 100–110 °C and 8 °C for temperatures above 120 °C. However, people tend to remember the doubling factor as a constant and the present IEC Loading Guide [B63] uses 6 °C.

In 1947, Dakin [B55] made a more significant advance in defining insulation aging rates by recognizing that aging of cellulose is the result of a chemical reaction, so the rate of change of a measured property can be expressed in the form of a reaction rate constant K_o. This can be applied by multiplying the rate constant, a function of temperature, by the time interval over which the aging takes place to find the percentage change in a property. Mathematically, the rate constant can be expressed by

$$K_O = A' \mathrm{e}^{\left[\frac{B}{\Theta + 273}\right]} \tag{I.1}$$

where

A' and B	are empirical constants
Θ	is the temperature in °C

Dakin showed that all aging rate data being compared in an AIEE committee, including Montsinger's data, could fit this relationship. The Dakin relationship, sometimes referred to as the Arrhenius reaction rate equation, has found wide acceptance in the world technical community in the ensuing years.

When the approach discussed is to be used for transformer life definition, there are two aspects involved, the first being the aging rate and the second being the life end-point criterion. These may be separated by treating life as a per unit quantity with the following as a life definition

$$Per\ Unit\ Life = A\,e^{\left[\frac{B}{\Theta_H + 273}\right]} \tag{I.2}$$

where

A	is a modified per unit constant, derived from the selection of 110 °C as the temperature established for “one per unit life”
B	is the same aging rate slope as Equation (I.1)
Θ_H	is the hottest spot temperature, °C

This equation expresses the dependence of the aging rate on temperature alone, and the absolute definition of “one per unit life” in units of time can encompass the end-point criterion and the other variables that affect the time to reach that end point, namely water and oxygen content of the insulation system. Each of these aspects may be discussed separately.

Many investigators have measured cellulose aging rates under controlled conditions and have presented their results in the above form. Some measured mechanical properties, some measured DP, and some measured gas evolution rates. To use the reaction rate constant for loading guide purposes, it is desirable to select a single rate slope, the constant B, which would be reasonably accurate for all forms of cellulose. Table I.1 represents the results of a search of the published literature to find that slope.

Dakin’s and Sumner’s data appear to have been shared within an AIEE committee. Head’s observations were most interesting in that he found that the *B* constants for mechanical properties (tensile strength, burst strength, elongation to rupture), DP and gas evolution were all the same within a range of ±440. Most of these data appear to be for non-thermally upgraded paper, but Lampe also evaluated thermally upgraded paper. His *B* constant in the table is one of the lowest, but his constant for thermally upgraded paper was even lower (9820). This could be the result of a limited temperature range of measurement, 135 °C–155 °C, from which it would be difficult to find an accurate slope. In recent evaluations to qualify thermally upgraded papers in the U.S. the data falls reasonably close to the slope of IEEE Std C57.92-1981. It should be pointed out that the ASA C57.92-1948 curve was not an Arrhenius curve, so it does not have a single value of *B* for all temperatures.

Table I.1—Aging rate constant—*B*

Source	Basis	*B*
Dakin [B55]	20% tensile strength retention	18 000
Sumner, et al. [B64]	20% tensile strength retention	18 000
Head, et al. [B65]	Mechanical/DP/gas evolution	15 250
Lawson, et al. [B66]	10% tensile strength retention	15 500
Lawson, et al. [B66]	10% DP retention	11 350
Shroff [B60]	250 DP	14 580
Lampe, et al. [B61]	200 DP	11 720
Goto, et al. [B67]	Gas evolution	14 300
ASA C57.92-1948	50% tensile strength retention	14 830 [a]
IEEE Std C57.92-1981	50% tensile strength retention	16 054
IEEE Std C57.91-1981	DT life tests	14 594

[a]120 °C to 150 °C temperature range.

From Table I.1 it may seem that there is not a single "right" value of *B*, but it must be remembered that all experimental data is subject to variability and the materials and test conditions for all of the investigators were certainly not identical. Placing the most emphasis on the more modern data (Shroff and Stannet [B60], Goto, Tsukioka, and Mori [B67], Head, Gale, and Lawson [B65]), it seems that a value of *B* of 15 000 would be appropriate and is used in the transformer insulation life curve in this loading guide.

For small distribution transformers, it is possible to define an end point for insulation life by means of functional life tests on the actual apparatus, as was done in the 1960s. However, this is not economically practical for power transformers. Another option is to make the definition in terms of a measurable physical characteristic—mechanical, electrical, or chemical. It can involve a percentage retention of the characteristic or an absolute level of the characteristic that is judged to be essential for functionality. Dielectric strength is the characteristic that would relate most closely to functionality, but it has been found that it deteriorates very slowly if the insulation is not disturbed mechanically. Thus, a mechanical characteristic, usually tensile strength, has customarily been chosen with an end-point criterion of 50% retained tensile strength. However, this has a deficiency in that 50% retained strength for initially weak paper could be a lower absolute strength than 25% retained strength for initially strong paper.

Functional life test evaluations on power transformer models were sponsored by EPRI in the 1978 to 1982 time period (EPRI [B57] [B80], EPRI [B58], and McNutt and Kaufman [B68]). They demonstrated that the ANSI 50 %-retained tensile-strength life criterion is very conservative. In one program (EPRI [B57], McNutt and Kaufman [B68]), small disk coils were aged for 6.2 times ANSI life without failure on short circuit and dielectric end-point tests. The aged coils had suffered only a 10% reduction of the initial dielectric strength. In a separate program (EPRI [B58]), disk windings were aged for 8.6, 12.0, and 15.3 ANSI life (see IEEE Std C57.92-1981) without failure on short-circuit and dielectric end-point tests.

An alternative end-point criterion, an absolute level of DP, has the advantages that only a small sample is required, measurement is simple, and the results tend to have less dispersion than tensile strength measurements. Many investigators (Fabre and Pichon [B59], Head, Gale, and Lawson [B65], Lampe and Spicar [B61], Lawson, Simmons, and Gale [B66], Yoshida, et al.[B69]) have shown good correlation between reduction of mechanical properties and reduction of DP. Using DP, an end-point criterion can be selected based on subjective judgment of "loss of useful mechanical properties." Various investigators Bozzini [B70], Fabre and Pichon [B59], Lampe, Spicar and Carranger [B71], Shroff and Stannet [B60], tend to choose different levels of DP for the endpoint, ranging from 100 to 250. A value of 200 seems a good compromise for power transformers, but smaller transformers subjected to lower mechanical stress levels in service could possibly accept a lower limit. Some small transformers have continued operation in service with DP below 100 (Bassetto and Mak [B72]).

Selection of an absolute value for useful life of transformer insulation at the reference temperature of 110 °C is very subjective. The general feeling at present is that the definition of 65 000 h given in IEEE Std C57.92-1981 (and earlier versions) may be excessively conservative. This value was chosen based on time to 50% tensile strength reduction of the insulation in sealed tube aging tests. The functional life tests on power transformer models previously mentioned confirmed that 65 000 was extremely conservative, perhaps by a factor of 2 or 3. At various times during the early deliberations about loading guides, lower levels of residual tensile strength were considered for the end point in sealed tube aging tests, down to a level of 20% residual (Sumner, Stein, and Lockie [B64]). At that level, the life could be considered to be 150 000 h and would be approximately equivalent to an end-point criterion of 200 residual DP. A slightly more conservative end point would be 25% residual tensile strength at a life of 135 000 h.

Functional life testing of distribution transformers was begun in 1957 [B73] to evaluate the life of 55 °C average winding rise insulation in that product. A factor of safety of 5 was applied to the most pessimistic results to obtain a life definition for distribution transformers of 180 000 h at 95 °C. More recent tests by individual manufacturers on the 65°C average winding rise insulation system distribution transformers have demonstrated a similar useful life at 110 °C. The normal life of 180 000 h has been used in this standard for many years.

Both the results of functional tests and service experience suggest that a normal life of 15–20 years at a winding hottest spot temperature of 110 °C is a reasonable expectation for both distribution and power transformers with well-dried and oxygen-free insulation systems. A 20-year life has long stood in the loading guides for distribution transformers. When an absolute value is placed on time to reach a selected life end point, the effect of all the significant variables must be considered, namely heat, water, and oxygen. Accelerated material aging tests that formed the basis for the traditional IEEE Std C57.92-1981 life curves (time to 50% retained tensile strength) were always carried out with very low moisture and oxygen contents in the aging cell. The same can be said for power transformer models and distribution transformers subjected to functional life tests. However, such is not always the case for in-service transformers, particularly those older units with open conservator oil preservation systems. An end of functional life criterion must, therefore, reflect not only a suitable end-point measurement level, but also appropriate moisture and oxygen levels in the insulation system of the operating transformer. For modern, well-sealed systems, these levels are comparable to those in the sealed cell material life evaluation tests.

The effect of the two controllable variables, water and oxygen, on aging rates has been extensively investigated. Fabre and Pichon [B59] stated a very simple rule for the effect of water, namely that the deterioration rate is directly proportional to the water content. Shroff's and Stannet's data [B60] support that relationship. The reference moisture level typical for material aging tests is 0.2% to 0.3% by weight, so the deterioration rates must be proportionally increased for higher moisture levels in operating transformers. However, the moisture level at the critical location, the hottest spot, is typically only about half of the average moisture level, because of moisture partitioning by temperature. Fabre and Pichon [B59] also investigated the effect of oxygen, comparing deterioration rates for a sealed low oxygen content system to an open free-breathing system. He found a deterioration acceleration factor of 2.5 for the open system. In a similar study, Lampe et al. [B71] found a factor of 10. All of these data give utilities good incentive to employ an oil preservation system that maintains low moisture and oxygen levels in their transformers.

Water, heat, and oxygen are the catalyst, the accelerator, and the active reagent in the oxidation of the oil in oil-filled transformers. The products of oil oxidation are acids, esters, and metallic soaps that attack the cellulose insulation with vigor and tenacity. The oxidation by-products also attack the oil producing additional oxidation by-products. If failures of the oil preservation system occur (loss of tank seal), then oil oxidation that dramatically accelerates insulation deterioration can be expected.

To summarize, the effect of heat on the useful life of a cellulose insulation material can be estimated on a per unit basis without regard to end-of-life criteria or internal conditions in the insulation system using Equation (I.2). Cumulative loss-of-life can be calculated for varying load conditions on this relative basis (see Table I.3 and Table I.4), with the result that one real day of operation will produce less or more aging than one day at the reference temperature of 110 °C (for a 65 °C average winding rise insulation system).

During development of the 1995 revision of IEEE Std C57.91, after the working group agreed to combine the existing separate guides into one document, some users of power transformers were concerned about the effect of dropping the old life curve for power transformers and adopting the life curve for distribution transformers. Their concern was the effect on the calculations of the insulation loss of life. To alleviate those concerns, the Working Group developed a table of alternative end of life values that the user could choose from, when performing loss of insulation life calculations. The authors failed to adequately explain why the table was created. That table is now included in this annex to document the historical information.

Table I.2—Options offered in the 1995 revision of IEEE Std C57.91—Normal insulation life of a well-dried oxygen-free 65 °C average winding temperature rise system at the reference temperature of 110 °C

Basis	Normal insulation life	
	Hours	Years
50% retained tensile strength of insulation (former IEEE Std C57.92-1981 criterion)	65 000	7.42
25% retained tensile strength of insulation	135 000	15.41
200 retained degree of polymerization in insulation	150 000	17.12
Interpretation of distribution transformer functional life test data (former IEEE Std C57.91-1981 criterion)	180 000	20.55
NOTE 1— Tensile strength or degree of polymerization (D.P.) retention values were determined by sealed tube aging on well-dried insulation samples in oxygen-free oil. NOTE 2 — Per IEEE Std C57.12.00-2010 (5.11.3) a minimum normal insulation life of 180 000 h is required. Other end of life criteria have been used historically for developing transformer loading. They are provided above for reference.		

I.3 Example calculations

In the first example (see Table I.3) with a mild overload, the life consumption was about 107.7% of one day at reference temperature, while for the short-time emergency load in Table I.4, with hottest spot temperature rising to 180 °C for a very brief time, the life consumption was about 18.6 times that of one day at reference temperature. It should be noted that in the development of Table I.3 and Table I.4 and in the sample calculation, the hottest spot temperature that was used was that for the end of each hour, with the assumption made that the temperature was constant for the full hour. The hottest spot temperature will vary during any one hour of loading. If this variation is small, there is little error in the calculation of aging hours, but if the variation is larger, such as 5 °C–10 °C, or more as around the hour 17:00 in Table I.4, the error can be significant. To minimize this error, it is recommended that a computer program be used in which the aging hours are calculated in small increments, such as every 3 min or 5 min.

One example of the use of the aging acceleration factor (FAA) would be for planned overloading. A 24 h variable load cycle would be input, which consists of variable loads and ambient temperature. The ambient and peak load might be high during the day and reduced during the night. Also an equivalent aging factor for a summer load cycle might be averaged with an equivalent aging factor for the winter. If the average was 1.0 for the year, then the kVA purchased was correct. If the average was above 1.0, then a higher kVA should be purchased. Or, economics might be factored in and the best return on the investment would be achieved by loading to, say, a 1.1 equivalent aging factor, which would accelerate slightly the use of the life of the unit and recover the investment more quickly. The user could then buy a newer transformer with more up-to-date technology if the old one failed due to this loading or other reasons.

In order to apply an absolute time scale to the life measurement, an appropriate end-of-life criterion must be selected. Tensile strength retention of 50% would be conservative and a lesser level could be accepted. Alternatively, an absolute level of DP, such as a value of 200, could be chosen as a level at which “useful mechanical properties” of the cellulose are still retained. In the Table I.4 example, the absolute percentage of total life lost in this 24 h period is given for the four “normal life” optional values for the user to choose from suggested in 9.1. In making this calculation, the aging acceleration effects of moisture and oxygen must be considered if these parameters are not maintained at low levels.

1 of Clause 5 gives aging acceleration factors.

This annex is based largely on a condensation of material presented in McNutt [B74].

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{25.857}{24} = 1.077 \tag{I.3}$$

where

F_{EQA}	is equivalent aging factor for the total time period
$F_{AA,n}$	is aging acceleration factor for the temperature that exists during the time interval Δt_n
n	is index of the time interval, Δt
N	is total number of time intervals
Δt_n	is time interval, h

This is equivalent to aging of 1.077 days or 25.848 hours at 110 °C.

$$\%\text{Loss of Life} = \frac{F_{EQA} \times 24 \times 100}{\text{Normal Insulation Life}} = \frac{1.077 \times 24 \times 100}{180{,}000} = 0.014\% \tag{I.4}$$

Based on normal insulation life of 180 000 h.

Table I.3—24 h load cycle aging calculation mild overload 100 MVA transformer (65 °C rise)

Time	Load (P.U. of N.P.)	Hottest spot temp. °C	Aging acel factor $F_{AA,n}$	Aging hours	Cumulative age hours
1:00	0.599	80.0	0.036	0.036	0.036
2:00	0.577	72.8	0.015	0.015	0.051
3:00	0.555	72.9	0.015	0.015	0.066
4:00	0.544	72.8	0.015	0.015	0.080
5:00	0.544	71.8	0.013	0.013	0.093
6:00	0.566	71.8	0.013	0.013	0.107
7:00	0.655	73.0	0.015	0.015	0.122
8:00	0.844	74.2	0.018	0.018	0.139
9:00	0.955	85.1	0.066	0.066	0.205
10:00	1.021	92.2	0.148	0.148	0.353
11:00	1.054	99.1	0.318	0.318	0.671
12:00	1.077	104.6	0.571	0.571	1.242
13:00	1.088	109.2	0.921	0.921	2.163
14:00	1.099	112.8	1.329	1.329	3.492
15:00	1.099	116.0	1.830	1.830	5.322
16:00	1.110	117.8	2.185	2.185	7.507
17:00	1.200	125.0	4.376	4.376	11.882
18:00	1.077	130.0	6.984	6.984	18.866
19:00	0.977	125.0	4.376	4.376	23.242
20:00	0.910	114.0	1.499	1.499	24.741
21:00	0.877	104.8	0.583	0.583	25.324
22:00	0.866	97.9	0.279	0.279	25.603
23:00	0.832	93.2	0.166	0.166	25.769
24:00	0.788	87.6	0.088	0.088	25.857

Table I.4—24 h load cycle aging calculation short time emergency 100 MVA transformer (65 °C rise)

Time	Load (P.U. of N.P.)	Hottest spot temp. Deg. °C	Aging acel factor $F_{AA,n}$	Aging hours	Cumulative age hours
1:00	0.599	80.0	0.036	0.036	0.036
2:00	0.577	72.8	0.015	0.015	0.051
3:00	0.555	72.9	0.015	0.015	0.066
4:00	0.544	72.8	0.015	0.015	0.080
5:00	0.544	71.8	0.013	0.013	0.093
6:00	0.566	71.8	0.013	0.013	0.107
7:00	0.655	73.0	0.015	0.015	0.122
8:00	0.844	74.2	0.018	0.018	0.139
9:00	0.955	85.1	0.066	0.066	0.205
10:00	1.021	92.2	0.148	0.148	0.353
11:00	1.054	99.1	0.318	0.318	0.671
12:00	1.077	104.6	0.571	0.571	1.242
13:00	1.088	109.2	0.921	0.921	2.163
14:00	1.099	112.8	1.329	1.329	3.492
15:00	1.099	116.0	1.830	1.830	5.322
16:00	1.110	117.8	2.185	2.185	7.507
17:00	1.690	180.0	424.922	424.922	432.429
18:00	1.077	130.0	6.984	6.984	439.413
19:00	0.977	125.0	4.376	4.376	443.789
20:00	0.910	114.0	1.499	1.499	445.288
21:00	0.877	104.8	0.583	0.583	445.871
22:00	0.866	97.9	0.279	0.279	446.150
23:00	0.832	93.2	0.166	0.166	446.316
24:00	0.788	87.6	0.088	0.088	446.403

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{446.403}{24} = 18.6 \tag{I.5}$$

$$\%\text{Loss of Life} = \frac{F_{EQA} \times 24 \times 100}{\text{Normal Insulation Life}} = \frac{18.6 \times 24 \times 100}{180{,}000} = 0.248\% \tag{I.6}$$

Using the normal life selections from Table I.2 gives the following:

a) 65 000 h = 0.687%
b) 135 000 h = 0.331%
c) 150 000 h = 0.298%
d) 180 000 h = 0.248%

Annex J

(informative)

Historical Elements of Transformer Loading

J.1 Historical Perspective

The set of temperature equations, known as the Clause 7 equations, have been used since the first edition of the IEEE Transformer Loading Guide published in 1945 [B75]. The equations were known before that date.

In fact, two engineers from General Electric Co, V. Montsinger and W. Cooney, formulated the equations as early as 1917 [B76] and 1925 [B77]. That was the year when the first AIEE standard, exclusively devoted to transformers, came out in 1925. The title was “AIEE standard No.13: Standards for transformers, induction regulators, and reactors”, the first version of today’s IEEE standard C57.12.00 “General requirements for liquid immersed distribution, power and regulating transformers”. In Appendix of that Standard were a set of four rules (13-600, 13-601,13-602, and 13-603) covering the recommendations for the operation of transformers, voltage regulators and reactors, where the oil and winding temperature limits were given for various loading conditions. The calculation of key temperatures was not part of the 13-600 standard, only the limits!

In his paper, W. Cooney acknowledged the priority and assistance of Montsinger in the derivation of temperature equations, which have been used for almost a century in all editions of IEEE and IEC loading guides ([B75],[B78], [B79]).

In the 1995 edition [B80], the temperature equations were retained as the Clause 7 equations, but an alternative method, developed by L. Pierce ([B81], [B82]), and known as Annex G, was also included.

The Montsinger-Cooney thermal model is based on the energy conservation law as applied to convective heat transfer during the heating and cooling of a transformer. Cooney [B77], in his derivation of the heating and cooling equation during transients, suggested that the power loss stored in a transformer's winding and core is given by $C\frac{d\Delta\theta}{dt}$, leading to a final description of the process by the differential equation:

$$W = C\frac{d\Delta\theta}{dt} + K\Delta\theta \tag{J.1}$$

where

W is the rate at which heat energy (power loss) is generated in the winding and core
C is the thermal capacity of the transformer, and
$K\Delta\theta$ is the rate at which heat energy dissipates from the transformer

All symbols are in accordance with the list of symbols given in Clause 7. The original paper's symbols are different. It is worth noting that temperature rises considered in the Cooney paper are a) top oil temperature above room temperature and b) average winding temperature above top oil temperature. The paper does not mention a hot spot temperature. However, Blume and Montsinger in [B83] points out, "Tests have shown that both the average rise and hottest-spot rise over the top oil follow the same law. Therefore, the same equation can be used."

After shutdown (W=0), the cooling of a transformer follows Newton's law of cooling according to:

$$C\frac{d\theta}{dt} = K\Delta\theta \tag{J.2}$$

The notable difference between (J.1) and (J.2) models is that in (J.2), the temperature itself is a target variable (also called solution or state variable), not the temperature rise, as suggested by the Montsinger-Cooney model.

This omission was not discovered until mid-1990-ties when MIT researchers, working on a transformer online monitoring project, published their results in 1997 [B84]. The authors pointed out that "*data recently collected from large transformers in the field indicate that the IEEE/ANSI top oil temperature rise over ambient temperature model is not as accurate as desired for an online monitoring system and fails to capture some basic thermal phenomenon*." The researchers modified the mathematical model so it would satisfy eq (J.2).

Nevertheless, (J.1) was the essential part of the first and subsequent editions of the Loading Guides right until this current revision, where it was corrected and included in Clause 7.

The top oil temperature in the Montsinger-Cooney model was represented by a sum of ambient temperature and top oil rise over ambient temperature:

$$\theta_{to} = \theta_a + \Delta\theta_{to/a} \tag{J.3}$$

The hottest spot temperature was represented as a sum of top oil over ambient and hottest spot over top oil temperature rise added to an ambient temperature as in (J.4):

$$\theta_{whs} = \theta_a + \Delta\theta_{to/a} + \Delta\theta_{whs/to} \tag{J.4}$$

The differential equation (J.1) has an analytical solution for both top oil and winding hottest spot temperature as follows:

$$\Delta\theta_{to/a} = \left(\Delta\theta_{to/a,u} - \Delta\theta_{to/a,i}\right)\left(1 - e^{-\frac{t}{\tau_{to}}}\right) + \Delta\theta_{to/a,i} \tag{J.5}$$

and

$$\Delta\theta_{whs/to} = \left(\Delta\theta_{whs/to,u} - \Delta\theta_{whs/to,i}\right)\left(1 - e^{-\frac{t}{\tau_w}}\right) + \Delta\theta_{whs/to,i} \tag{J.6}$$

$\Delta\theta_{to/a,i}$	is the initial top oil over ambient temperature rise
$\Delta\theta_{whs/to,i}$	is the initial winding hottest spot over top oil temperature rise
$\Delta\theta_{to/a,u}$	is the ultimate top oil temperature rise
$\Delta\theta_{whs/to,u}$	is the hottest spot over top oil temperature rise
τ_{to}	is oil time constants
τ_w	is the winding time constants

Ultimate top oil temperature rise and hot spot temperature rise are steady-state values and calculated using (J.7) and (J.8).

$$\Delta\theta_{to/a,u} = \Delta\theta_{to/a,r}\left[\frac{1+RK^2}{1+R}\right]^n \tag{J.7}$$

$$\Delta\theta_{whs/to,u} = \Delta\theta_{whs/to,r} K^{2m} \tag{J.8}$$

where

n is the oil exponent, reflecting a cooling mode of convective heat transfer
m is the winding exponent, reflecting a cooling mode of convective heat transfer.

The values for these exponents are equal to or less than one.

The time constant at rated losses is given by:

$$\tau_{to,r} = \frac{C\Delta\theta_{to,r}}{P_{tot,r}} \tag{J.9}$$

were

C is thermal capacitance, watt-hours/K
$P_{tot,r}$ is total loss at rated load, W

The following equation gives the thermal capacity for ONAN transformers:

C = 0.06 (weight of core and coil assembly in pounds) + 0.04 (weight of tank and fittings in pounds) + 1.33 (gallons of oil).

If the exponent $n = 1.0$, no correction of time constants is required for any load and any initial temperature. If n is less than 1, the time constant must be modified for different overload cycles, as shown in the following equation:

$$\tau_{to} = \tau_{to,r} \frac{\left(\frac{\Delta\theta_{to,u}}{\Delta\theta_{to,r}}\right) - \left(\frac{\Delta\theta_{to,i}}{\Delta\theta_{to,r}}\right)}{\left(\frac{\Delta\theta_{to,u}}{\Delta\theta_{to,r}}\right)^{\frac{1}{n}} - \left(\frac{\Delta\theta_{to,i}}{\Delta\theta_{to,r}}\right)^{\frac{1}{n}}} \tag{J.10}$$

The set of equations (J.3) – (J.10) represents a thermal model introduced by Montsinger and Cooney and was included in all previous editions of the Loading Guide. The Montsinger-Cooney model is a special case of the modified thermal model, which is now included in Clause 7 as an alternative model to the Pierce model. When the ambient temperature is assumed to be constant during a transformer operation, the Montsinger-Cooney model gives the same results as the alternative model. Those conditions do not occur in practice, therefore using the Montsinger-Cooney model is not recommended.

Apart from misrepresentation of Newton's law of cooling, the Montsinger-Cooney model assumed that the oil inside the winding cooling ducts was of the same temperature as the oil in the tank during the steady state and in the transient state. When the model was first proposed, there were few experimental investigations of the winding hottest spot temperature during various loading conditions. It appears that the mathematical representation of Newton's law of cooling (2) was unknown to engineers at that early time of transformer manufacturing and operation. In the first decade of the 19th century, the prevailing theory of convective heat transfer was the film theory of convection by Irving Langmuir [B85].

Montsinger and Cooney admitted that the equations they derived were not very accurate, but they were hopeful that the model could still be helpful for transformer loading calculation. Indeed, the equations were reasonable approximations of the step response from one steady state load to another, provided that the ambient temperature is constant. Therefore, the model was adequate for the heat run tests under well-controlled testing room temperature.

The investigations ([B81], [B82], [B86]) have shown that for the operating transformers during overloads, the oil temperature in the winding cooling ducts rises rapidly at a time constant equal to the winding. During this transient condition, the oil temperature adjacent to the hot spot location is higher than the top oil temperature in the tank. This phenomenon results in winding hottest spot temperature greater than predicted by the Montsinger-Cooney model. The measurements of the hottest-spot over top oil temperature rise consistently confirm the non-exponential nature of the rise (often called thermal overshoot). This conflicts with Montsinger-Cooney theory of exponential increase/decrease of the temperature rise.

An alternative set of equations that considered the winding duct oil temperature was included in Annex G of the 1995 Loading Guide. The derivation of the equations is made by L. Pierce in [B81] and [B82]. A Personal Computer (PC) BASIC computer program is included in Annex G of the 1995 edition to perform the calculations in a step-by-step procedure.

The Pierce thermal model has been proven to be adequate by many research and field engineers ([B86], [B87], [B88], [B89]). The Pierce model is increasingly used as the reference to benchmark many emerging and advanced transformer thermal models. Therefore, the Pierce model is incorporated into Clause 7 of the main body of this revision.

In the 1990s, the technology focus in the transformer industry was on thermal performance and loading capability. Many transformers underwent planned overloading by utilities to maximize the return on investment in this expensive equipment. In the 1980s, fiber optic temperature detectors permitted direct measurements of the hottest spot temperature in full-size transformers. Initially, the research was concentrated on steady-state performance. In the 1990s, additional research was conducted on transient performance. As reported in 1992 by W. J. McNutt [B90], "...The thermal equations provided in the loading guide are recognized to be grossly inaccurate for some cooling modes and not precisely correct for others."

The Montsinger-Cooney thermal model was a reasonable approximation for steady-state loads. Their hottest spot equation is inaccurate for high short-term overloads and cold load pickup conditions. Since the Montsinger-Cooney model has been conclusively proven inadequate for high short-term overloads and online transformer monitoring [B84], it was removed from this revision of the Loading Guide.

The modified thermal model, called the alternative model, is given in Clause 7. The alternative model follows energy conservation and Newton's cooling law with variable ambient temperature. The model has no analytical solution and thus must be solved numerically.

Earlier loading guides utilized a two-step approximation of the load cycle in evaluating overloads. The load is assumed to consist of an initial load below nameplate rating plus an overload step. The initial load and overload values are determined from the equivalent load cycle. Primarily, the two-step method was proposed to generate the so-called loading tables and charts, now removed from all IEEE and IEC editions. The open-source code is designed to process the actual load cycle in a much more efficient way; thus, the clause "Method of converting actual to equivalent load cycle" with all references were removed from this revision.

Annex K

(informative)

Proof that Clause 7 model is a special case of Annex G model in C57.91-2011

K.1 Derivation of the key equation

The winding hotspot temperature rise over top oil temperature model is based on equation (16) from [IEEE C57.91-2011]. This can be re-written as:

$$\Delta\theta_{whs/to}(t) = (\Delta\theta_{whs/to,u} - \Delta\theta_{whs/to,i})(1 - e^{-\frac{t}{\tau_w}}) + \Delta\theta_{whs/to,i} \quad \text{(K.1)}$$

First, we are going to prove that (K.1) is a solution to a differential equation (K.2)

$$\tau_w \frac{d\Delta\theta_{whs/to}}{dt} = \Delta\theta_{whs/to,u} - \Delta\theta_{whs/to} \quad \text{(K.2)}$$

with initial value t=0 $\Delta\theta_{whs/to}(0) = \Delta\theta_{whs/to,i}$

where

$\Delta\theta_{whs/to,i}$ is the initial value of $\Delta\theta_{whs/to}$ at t=0

Proof:

Let

$$\Theta = \Delta\theta_{whs/to} \quad \text{(K.3)}$$

then (K.2) becomes:

$$\tau_w \frac{d\Theta}{dt} = \Theta_u - \Theta \quad \text{(K.4)}$$

It turns out to be a non-homogeneous separable differential equation:

$$\frac{d\Theta}{dt} + \frac{\Theta}{\tau_w} = \frac{\Theta_u}{\tau_w} \quad \text{(K.5)}$$

Rearranging terms to isolate the derivative:

$$\frac{d\Theta}{dt} = -\frac{\Theta - \Theta_u}{\tau_w} \quad \text{(K.6)}$$

Rearranging again to move Θ and $d\Theta$ terms to one side and dt to the other:

$$\frac{d\Theta}{\Theta-\Theta_u} = -\frac{dt}{\tau_w} \tag{K.7}$$

Integrating both sides gives:

$$\int_{\Theta_i}^{\Theta(t)} \frac{d\Theta}{\Theta-\Theta_u} = -\int_0^t \frac{dt}{\tau_w} \tag{K.8}$$

$$\ln(\Theta(t)-\Theta_u) - \ln(\Theta_\mathrm{i}-\Theta_u) = -\frac{t}{\tau_w} + \frac{0}{\tau_w} \tag{K.9}$$

$$\frac{\Theta(t)-\Theta_u}{\Theta_\mathrm{i}-\Theta_\mathrm{u}} = e^{-\frac{t}{\tau_w}} \tag{K.10}$$

$$\Theta(t) = \Theta_u + (\Theta_\mathrm{i}-\Theta_\mathrm{u})e^{-\frac{t}{\tau_w}} \tag{K.11}$$

Subtracting Θ_i from both sides, and substituting (K.3) gives the final equation:

$$\Theta(t) - \Theta_\mathrm{i} = (\Theta_u-\Theta_\mathrm{i}) - (\Theta_\mathrm{u}-\Theta_\mathrm{i})e^{-\frac{t}{\tau_w}} \tag{K.12}$$

$$\therefore \Delta\theta_{whs/to}(t) = (\Delta\theta_{whs/to,u} - \Delta\theta_{whs/to,i})(1-e^{-\frac{t}{\tau_w}}) + \Delta\theta_{whs/to,i} \tag{K.13}$$

Equation (K.13) is identical to (K.1) and Equation (16) in [IEEE C57.91-2011]

Substituting equation (18) from [IEEE C57.91-2011] in (K.2) above gives:

$$\tau_w \frac{d\Delta\theta_{whs/to}}{dt} = \Delta\theta_{whs/to,r}K^{2m} - \Delta\theta_{whs/to} \tag{K.14}$$

Substituting (22) in (K.14) yields:

$$\frac{C\Delta\theta_{whs/to,r}}{P_{tot.r}}\frac{d\Delta\theta_{whs/to}}{dt} = \Delta\theta_{whs/to,r}K^{2m} - \Delta\theta_{whs/to} \tag{K.15}$$

Dividing both sides of (K.15) by $\frac{\Delta\theta_{whs/to,r}}{P_{tot.r}}$ and assuming m=1 for all oil forced cooling modes gives:

$$C\frac{d\Delta\theta_{whs/to}}{dt} = P_{tot,r}\cdot K^2 - P_{tot,r}\frac{\Delta\theta_{whs/to}}{\Delta\theta_{whs/to,r}} \tag{K.16}$$

Assuming no temperature correction for losses ($K_{HS}=1$) at hotspot location simplifies (G.14) from [IEEE C57.91-2011] as

$$\dot{Q}_{gen,hs} = K^2(P_{hs,r} + P_{ehs,r}) \tag{K.17}$$

Assuming no viscosity correction and that oil hotspot temperature is equal to top oil temperature (duct oil is the same as top oil) simplifies (G.16A) as

$$\dot{Q}_{lost,hs} = \frac{\Delta\theta_{whs/to}}{\Delta\theta_{whs/to,r}} \left(P_{hs,r} + P_{ehs,r}\right) \tag{K.18}$$

Total load loss at winding hotspot location is

$$P_{tot,r} = P_{whs,r} + P_{ehs,r} \tag{K.19}$$

The thermal capacity of windings

$$C = m_{whs} \cdot c_{p,whs} \tag{K.20}$$

Substituting (K.17) - (K.19) in (G.17) from [IEEE C57.91-2011] gives

$$m_{whs} \cdot c_{p,whs} \left(\frac{d\theta_{whs/to}}{dt}\right) = \dot{Q}_{gen,whs} - \dot{Q}_{lost,whs} \tag{K.21}$$

$$C \frac{d\theta_{whs/to}}{dt} = P_{tot,r} \cdot K^2 - P_{tot,r} \frac{\Delta\theta_{whs/to}}{\Delta\theta_{whs/to,r}} \tag{K.22}$$

Finally, assuming top oil temperature is a constant equal to $\theta_{to,r}$ (very unlikely during transformer operation, but could be observed at the end of a temperature rise test at rated load), the left-hand side of (K.21) may be modified to look like the left-hand side of (K.14) without loss of generality. Then (K.21) can be re-written as:

$$\therefore C \frac{d\Delta\theta_{whs/to}}{dt} = P_{tot,r} \cdot K^2 - P_{tot,r} \frac{\Delta\theta_{whs/to}}{\Delta\theta_{whs/to,r}} \tag{K.23}$$

(K.23) is now identical to (K.16) above, proving that Clause 7 of older Loading Guides and alternative methods in the current Clause 7 are special cases of the more general Annex G model of 1995 and 2011 editions. The Annex G model is a general case with respect to older Clause 7 models, meaning that it is a superior method because, in addition to all the parameters considered by the older Clause 7 model, it takes into account: a) daily fluctuations of oil and ambient air temperatures, b) change in oil viscosity with oil temperature and c) change in the winding's resistance as a function of temperature for calculating load loss.

Both methods (Annex G and Clause 7) should produce the same results at the end of the heat run test in the steady state at rated load for OD cooling, provided the ambient temperature is well above 0 °C and has not changed during at least the last one hour of the test.

Annex L

(informative)

Bibliography

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this standard. Reference to these resources is made for informational use only.

NOTE TO PUBLISHING: The Mandatory Editorial Coordination (MEC) reviewer commented that an annotated bibliography is not approved. The MEC Reviewer noted placing the bibliography in alphanumeric order could be performed during publication.

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