Transformer Overloading and Assessment of Loss-of-Life for Liquid-Filled Transformerss

Final Project Report

Power Systems Engineering Research Center

Empowering Minds to Engineer the Future Electric Energy System

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Power Systems Engineering Research Center

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Executive Summary

This is the final project report for research on *Transformer Overloading and Assessment of Loss-of-Life for Liquid-Filled Transformers* in electric power systems. This subject has been addressed by many researchers and standards over the years, however, still with no clear consensus. There are several areas where the addition of more advanced sensor and monitoring technology can improve the remaining life expectancy estimations. This research developed an optimization methodology to minimize the cost and select the proper transformer size for new applications and to optimize the replacement of transformer for an existing system (retrofit applications). It is anticipated that the method described here will help utilities in making decisions to minimize revenue requirements of the transformer over the long run to attain overall economic efficiency.

Although the incentive to loading power transformers beyond their nameplate rating has always been existed in the past, recently utilities show more inclination to fully utilize them to achieve greater profit. One of the basic criteria which limit the transformer loading capabilities is the hottest-spot temperature of windings. According to the IEEE Std. C57.91-1995, for the thermally upgraded paper, it is limited to 110°C @ 30°C ambient temperature for a 65°C average winding temperature rise. Higher winding hottest-spot temperature causes degradation (decrease in mechanical strength and increase brittleness) of the winding insulation and increases the potential of transformer failure. Gas bubbles may also form at elevated operating temperature, which may also cause the dielectric breakdown.

Under certain operating conditions, a transformer may be safely loaded beyond its nameplate rating. For every 1°C ambient temperature reduction (from standard 30°C) releases approximately 1% of overloading capability. The cold winter weather allows transformers for some overloading or saving of the insulation life. While in the summer, transformers run at higher ambient temperatures. The insulation degrades rapidly under these high temperatures and transformer life could be shortened substantially.

Utilities usually size and operate their transformers by matching the rating with the present demand and taking into consideration the future growth. Industry standard suggests transformer life expectancy to be approx. 30 years under “normal” operating conditions. In order to defer transformer replacement cost or cost of adding a second transformer under certain conditions, utilities may overload the transformer beyond the nameplate rating and accept calculated reduced life. This research addressed this very issue of economic decision based on the transformer remaining life-expectancy model. The probability tree structure is utilized to describe the future load growth pattern and uncertainty. Together with probability tree model, the transformer thermal model has been employed to calculate service life of the transformer and determine when to replace an existing transformer.

Following the concepts of Per-Unit Life, Relative Aging factor, Equivalent Aging, and end-of-insulation-life criteria, two simple equations have been developed to estimate the transformer remaining life. A Windows based, object oriented program has been developed to calculate the hottest-spot temperature, the top- and the bottom-oil temperature for each model. The program also calculates the loss-of-insulation-life, the remaining life, and energy losses following the methodology developed in this research.

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NOMENCLATURE

Symbols Related to Thermal Models and Loss- of- Life Calculation

C Transformer thermal capacity, $\text{watt - min./}^{\circ}\text{C}$

C_{PW} Specific heat of winding material, $\text{watt - min./lb.}^{\circ}\text{C}$

ΔT_{BO} Bottom-oil temperature rise over ambient

ΔT_{G} Winding hottest-spot temperature rise over top-oil temperature

ΔT_{GR} Winding hottest-spot temperature rise over top-oil temperature at rated load

$\Delta T_{G,i}$ Initial winding hottest-spot temperature rise over top-oil temperature

$\Delta T_{G,u}$ Ultimate winding hottest-spot temperature rise over top-oil temperature

ΔT_{HS} Incremental hottest-spot temperature difference between iteration

$\Delta T_{HS/WO}$ Winding hottest-spot rise over adjacent duct-oil temp. at hottest-spot location.

ΔT_{IMR} Average oil rise (IEC)

ΔT_{OAVG} Incremental average bulk-oil temperature between iteration

$\Delta T_{TDO/BO}$ Duct-oil temperature rise over bottom-oil temperature

$\Delta T_{TDOR/BOR}$ Duct-oil temperature rise over bottom-oil temperature at rated load

ΔT_{TO} Top-oil rise over the ambient temperature

ΔT_{TOR} Top-oil temperature rise at rated load

$\Delta T_{TO,i}$ Initial top-oil temperature rise

$\Delta T_{TO,u}$ Ultimate top-oil temperature rise

$\Delta T_{TO/BO}$ Top- and bottom-oil temperature difference

ΔT_{W} Incremental winding temperature difference between iteration

ΔT_{WO} Duct-oil temperature rise at winding hottest-spot location over bottom oil

ΔT_{WR} Average winding rise temperature at rated load

F_{AA} Relative aging factor

F_{EQU} Equivalent aging factor

H Hottest-spot factor

HHS Location of hottest temperature on the winding, per unit of winding height

k Radiation constant, $\text{watt/}^{\circ}\text{C}$

K Transformer loading, per-unit

L	Insulation life, per unit
μ_{HS}	Oil viscosity at hottest-spot location
μ_{HSR}	Oil viscosity at hottest-spot location at rated load
μ_{W}	Oil viscosity in the duct
μ_{WR}	Oil viscosity in the duct at rated load
m	Winding exponent
M_W	Winding mass, lb
n	Oil exponent
P_{EHSR}	Eddy current loss at rated load and at hottest-spot temperature
P_{ER}	Eddy current loss at rated load
P_{HSR}	Winding loss at rated load and at hottest-spot temperature
P_{loss}	Total losses, watt
$P_{loss,i}$	Initial total losses, watt
$P_{loss,u}$	Ultimate total losses, watt
P_R	Total losses in watts at rated load
P_T	Transformer total losses, per-unit
P_{TR}	Total transformer losses at rated load
P_W	Winding loss, watt
P_{WHSR}	Winding loss at hottest-spot temperature
P_{WR}	Winding loss at rated load
Q_{Core}	Heat generated from core loss
Q_{HSABS}	Heat absorbed in winding at hottest-spot location
Q_{HSGEN}	Heat generated in winding at hottest-spot location
Q_{HSLOST}	Heat lost from winding hottest-spot location to oil
Q_{OGEN}	Heat generated in oil
Q_{OLOST}	Heat lost from oil to air
Q_{Stray}	Heat generated from stray loss
Q_{WABS}	Heat absorbed in winding
Q_{WGEN}	Heat generated in winding
Q_{WLOST}	Heat lost from winding to oil
R	Transformer loss ratio (load losses/no-load losses)

ΣMC_P	Summation of product of mass and specific heat of tank, core, and oil excluding winding
τ_G	Winding time constant
τ_{GR}	Winding time constant at rated load
τ_{TO}	Oil time constant
τ_{TOR}	Oil time constant at rated load
T_A	Ambient temperature
T_{BO}	Bottom-oil temperature
T_{BOR}	Bottom-oil temperature at rated load
T_{DAO}	Average duct-oil temperature
T_{DAOR}	Average duct-oil temperature at rated load
T_{HS}	Hottest-spot temperature
T_{HSR}	Hottest-spot temperature at rated load
T_k	Resistance correction factor
T_{KHS}	Winding resistance correction factor for hottest-spot temperature
T_{KW}	Winding resistance correction factor
T_{OAVG}	Average bulk-oil temperature
T_{OAVGR}	Average bulk-oil temperature at rated load
T_{TDO}	Top duct-oil temperature
T_{TDOR}	Top duct-oil temperature at rated load
T_{TO}	Top-oil temperature
T_{TOR}	Top-oil temperature at rated load
T_W	Average winding temperature
T_{WR}	Average winding temperature at rated load
x	Exponent of duct-oil rise
y	Exponent of average oil rise
z	Exponent of bulk-oil temperature difference

Symbols Related to Economic Evaluation

α	Load growth rate
AEC	Annualized energy cost
$ALCR$	Auxiliary losses cost rate, \$/kW
ALL	Auxiliary losses
C_{TR}	Cost of transformer
CC	Carrying charge
CF	Cost of random failure
CLL	Cost of load losses
$CNLL$	Cost of no-load losses
COL	Cost of losses
CRF	Capital recovery factor
CRR	Capitalized revenue requirement
D_B	Depreciation
D_T	Tax depreciation for income tax purposes
DC	Demand charge, \$/kW.yr
e	Energy cost escalation rate
$\bar{e}$	Average annual inflation rate
E_A	Annual equity return
EPR	Equivalent peak ratio
ERR	Equivalent revenue requirement
$f(t)$	Probability distribution function
$F(t)$	Cumulative distribution function
$f(S_T)$	Transformer cost function
$f_{LL}(S_T)$	Transformer load losses function
$f_{NLL}(S_T)$	Transformer no-load losses function
FCR	Fixed charge rate
$h(t)$	Hazard function
i	Cost of capital rate or discount rate
i_b	Borrowed money rate
i_d	Depreciation rate

i_e	Equity return rate
i_t	Tax rate
λ	Debt ratio, failure rate
LL	Load losses
$LLCR$	Load losses cost rate, $/kW
MV	Market value of transformer
N	Transformer life
$NLCR$	No-load losses cost rate, $/kW
NLL	No-load losses
P_A	Annual production expense
P_{core}	Core or no-load losses, kW
$P_{cu}(t)$	Time-varying load losses, kW
$P_{cu,max}$	Annual maximum load losses, kW
PA	Probability that the auxiliary cooling will be on
PR	Peak ratio or per-unit loading
PRF	Peak responsibility factor
R_A	Annual revenue
RR	Revenue requirement
S_T	Transformer maximum rating
SI	System investment cost, $/kW
T	Income tax
TLF	Transformer loss factor
TOC	Total owing cost
UI	Unrecovered investment

1. Introduction

Sizing of a large new power transformer or replacement of an existing transformer is done traditionally from simplified analysis and technical considerations. The conventional loss evaluation technique, defined by the "Total Owning Cost (TOC)", is still routinely utilized by utilities to evaluate the values of transformer losses during procurement. Total cost of losses during transformer operating life is comparable to its initial purchase price, and the loss evaluation is always recommended during procurement. The TOC method, however, has limitations. Regardless of the load cycles, ambient conditions, and future load growth, transformer's life (typically 30 yrs.) is assumed to be constant. Load cycles, ambient conditions, and future load growth and possible overloading including uncertainties are very important factors that affect transformer's life, hence the total cost. Also, a decision has to be made, whether to replace the transformer immediately or to delay its replacement. Utility's engineers should evaluate the remaining life of the existing transformer due to overloading, together with economic evaluation.

This research utilizes a simplified optimization strategy and an improved method for new transformer sizing, cost evaluation and perhaps delay replacement analysis of existing transformers. The method is based on the loss-of-life information from the hottest-spot temperature calculated from transformer thermal model.

Most transformer failures are related to the deterioration of insulation with. For liquid-filled transformers, the traditional insulation system is thermally upgraded oil-impregnated paper. The concept of insulation integrity has led to the development of the thermal insulation aging that has been known to be a function of both time and temperature (Arrhenius Reaction Rate Theory). However, transformer loss-of-life at various elevated-operating temperatures cannot be accurately estimated and the corresponding remaining life expectancy is considered to be conservative.

This final report is comprised of 8 chapters followed by three Appendices. Chapter 2 discusses the design fundamentals of liquid-filled transformers. Various "On-line/Off-line" monitoring techniques are also discussed.

In Chapter 3, two (2) thermal models from the IEEE loading guide, C57.91-1995 [1] are discussed. A third model from the IEC loading guide, IEC 354-1991 [2] is also used to compare. A comparison of the IEEE and IEC models is attached in the Appendix C. A PC based computer program on Windows operating system is written to calculate all temperature profiles and transformer loss-of-life including the Graphic User Interface (GUI) helps user to easily access data and perform analysis.

Chapter 4 discusses the probabilistic modeling including the Monte Carlo simulation to calculate the loss-of-life.

Chapter 5 has been dedicated to the development and discussion of economic evaluation, Conventional loss evaluation, characterized by the "Total Owning Cost (TOC)". A more detailed technique called the Minimum Revenue Requirement method, which is applicable to Investor-Owned Utilities (IOU's) is also introduced.

Chapter 6 proposes the optimization scheme that will determine the size of a new transformer and provide a strategy for delaying replacement of an existing transformer based on load cycle, present load, future growth, ambient operating conditions, and economic consideration. Transformer cost and losses are derived by curve fitting data obtained from various industry sources. Failure cost is also included in this scheme. The probability tree structure is applied to future load growth that takes into account the uncertainty. A basic computer program is written to estimate the transformer life, energy losses, and financial results.

Chapter 7 includes the numerical calculations. Different case studies are discussed including new transformer sizing and “delay replacement” strategy.

Chapter 8 includes conclusions and recommendations.

In summary, this research provided an integrated method for transformer sizing and provides an optimal solution for transformer replacement. Windows based computer program is written to provide system planning engineers with fast, convenient, and practical solutions.

2. Transformer Design and Thermal Loading

2.1 Introduction

Emergency and/or planned overloading of oil-filled power transformers beyond their nameplate rating depends on several factors including the design, operation, routine oil testing and maintenance program, daily loading and load cycle, ambient conditions and applications. For most common applications, transformer overloading capabilities and the life expectancy are determined by the winding “hottest-spot” temperature and its duration.

For all liquid-filled transformers, the insulation system is composed of thermally-upgraded oil-impregnated paper. This cellulose paper insulation used today must maintain its mechanical strength and withstand the stresses that occur with surges and must be able to withstand detrimental chemical transformations.

2.2 Basic Design Considerations

Over time, oil-impregnated paper insulation used in liquid-filled transformer winding loses mechanical and electrical strength and becomes brittle when exposed to elevated operating temperatures. These results are obtained from aging tests of transformers or are obtained from laboratory tests on isolated pieces of insulation material.

A typical simplified transformer heating and cooling model used for the analysis is illustrated in Figure 2.1. The winding I^2R and eddy-current losses, the core losses, and the stray losses in the tank and metal support structures are the principal sources of heat. There exists a significant difference between the top- and bottom-oil temperature rises, and this will vary depending on the type of cooling systems and winding construction. The difference between the top and bottom oil rises with forced oil-cooling is in the order of only a few degrees, whereas this difference is several times larger for forced air-cooled transformers.

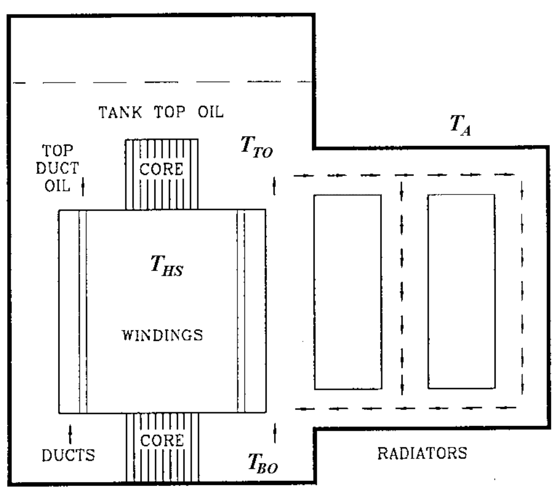

Figure 2.1 Transformer fluid flow

Four modes of cooling most commonly employed in liquid filled transformers are: (1) Natural convection of oil and natural convection of cooling air over the radiator (OA); (2) Natural convection of oil with forced convection of air over the radiator – either single stage (OA/FA) or multiple (most common, two) stages (OA/FA/FA); (3) Directed forced oil flow and forced airflow (DFOA); and (4) Non-directed forced oil flow; and forced airflow (NDFOA).

OA cooled transformers are used in the distribution system and the ratings are typically limited to less than 2.5 MVA. Transformers rated between 2.5-100 MVA are designed for "Fan Cooling" (OA/FA/FA). A single-stage "OA/FA cooling" is used for the lower ratings (2.5-10MVA range). Larger distribution transformers (10-100MVA) are normally designed to have two stages of fan cooling (OA/FA/FA). Transformers rated above 100 MVA ranges are generally "FOA type" (or forced oil and forced air cooled design).

Another fact to be remembered is that the expected transformer life (common practice) is estimated between 25-30 years, depending on the utility's accounting preference. However, transformer operating for 40 years (or more) of service life is not uncommon in the industry. This "normal life period" assumes some overloads but also includes long periods of light loads and lower ambient temperatures.

2.2.1 Transformer Construction and Its Thermal Performance

Heat can flow from the core to the oil. However from the winding, heat must go through the insulation. Large transformers are designed so that at least one side of each insulated coil can transfer heat directly to the oil. The heat transfer rate is proportional to the insulation thermal conductivity and exposed surface area and inversely proportional to the insulation thickness [3].

The core and windings define the basic dimensions of the transformer tank's length and width, with the tank height determined by the level of oil necessary to cover the core (including tap changer). Additional space for oil circulation is added on to the basic dimensions. Tank design affects the ability of the transformer to dissipate heat to the surroundings. Vertical location of the core and winding within the tank also will influence the rate of heat transfer to the oil. At elevated temperature, the transformer oil is oxidized and forms sludge that reduces the heat flow from the winding, thereby, elevating its temperature. The use of inert gas to minimize sludge formation, combined with oil filtration, controls the effects of oil oxidation.

Core - Magnetic cores for large power transformers are made of thin laminations of grain-oriented-silicon-steel. Currently five main grades of silicon steel are widely used in the transformer industry: M2, M3, M4, M5, and M6 in increasing order of gauge (from 7 to 14 mil thickness) and core losses. Besides the type of material and lamination thickness, the operating flux density in the core determines core losses. Typically the design value of the flux density in silicon steel core ranges from 1.6-1.8T (Tesla = Wb/m^2). The core flux density, core cross-sectional area, voltage, frequency and number of turns are related by the basic equation:

$$E = 4.44\, fNB_m A \qquad (2.1)$$

Where, E is the exciting [rms] voltage (V) (assumed sinusoidal voltage), f is the frequency (Hz), N is the number of turns, B_m is the maximum flux density in (T), and A is the cross-sectional area of steel core (m^2). When the frequency and the area of the core are constant, the maximum flux density is proportional to ratio of exciting voltage and turns (or volts per turn ratio, E/N).

Typically, under no-load condition and at rated voltage, transformers draw very little exciting current (rms value of 2-4% of the full load current). Because of the nonlinear magnetization characteristic of the steel core, and since the flux-density in a typical design is above the "knee point", the exciting current contains harmonics. A typical exciting current consists of (45%) 3rd, (15%) 5th and (3%) 7th and smaller percentages of higher frequency harmonics [4]. In current design practices, the limit on the value of flux density is imposed by the amount of distortion in the exciting current and the corresponding generation of audio noise. It is considered a good practice to keep the flux density at a lower value of approximately 1.7T.

<u>Coil and Winding</u> - Transformer coils are designed to get the required number of turns into a minimal space. At the same time, the conductor cross-section must be large enough to be able to carry the current without overheating. These coils may be made of copper or aluminum. Aluminum winding is generally cheaper and has lighter weight (30% of copper's weight). However, the aluminum winding has higher losses (62% higher resistance). At present, the typical payback period for Cu is estimated between 5 to 8 years.

The transformer size and the overall design are basically dictated by two main factors called "Specific Magnetic Loading" (flux density "B" in the core) and "Specific Electric Loading" (current density in the winding). Transformer size is related to load losses (winding), maximum magnetic flux density and current density through an empirical equation of the form [5]

$$J = K\ f\ B_m \left(\frac{A}{s}\right)\left(\frac{\%P_{cu}}{K_{eddy}}\right) \qquad (2.2)$$

Where, J is the current density in conductor (A/mm^2) , B_m is the maximum flux density (T), A is the cross-section area of core (m^2), s is the mean turn length (m), $\% P_{cu}$ is in the core loss expressed as a percent of transformer rating, and K_{eddy} = 1.05-1.2. The constant K depends upon the unit and conductor material. Other constraints such as lowest unit cost, minimum total owning cost, guaranteed load loss, etc., are also utilized to optimize the design.

Typical current densities in a design may vary by a factor of 2:1. It depends primarily on the winding material (copper vs. aluminum) and the cooling method. In "Class B" insulated transformers (most common design with 65°C avg. winding rise), the maximum value of current density varies from about 3.5 A/mm^2 smaller to 6.0 A/mm^2 for large transformers with forced cooling. Table 2.1 [5] shows the range and the average value of current and flux densities.

Table 2.1: Range and average value of current density and flux density in various types of oil-filled transformer with copper winding

Class of transformer	Current density (A/mm^2) Range	Average	Flux density (T)
Generator Step-up	2.6-4.0	2.9	1.70
Transmission	3.7-6.0	4.3	1.55
Distribution	2.0-2.5	2.3	1.55

Cooling Equipment - The radiator cooling now used have a fairly constant heat dissipation rate per unit length. Cooling tubes that are farther spaced and the larger the tube surface area, the greater is the cooling capability. Some manufacturers use a flat plate design for cooling tubes, allowing more surface area per tube and reducing manufacturing costs. Pumps, when utilized, are used to increase the flow of oil, thereby increasing the efficiency of the radiators and minimizing the temperature difference between the top-oil and at the bottom-oil in the tank.

Cooling Mode - Natural draft (air) cooling (AA) is utilized for small transformers. However, as the transformer size increases, the cooling surface area is insufficient. Additional cooling must be provided. Oil immersion increases the heat transfer rate and the addition of external radiators attached to the tank increases the cooling surface area (OA).

Forcing air can substantially increase the rate of cooling above the self-cooled rating. Larger MVA transformers may be designed for either one or two stages of forced air-cooling (OA/FA or OA/FA/FA). Forced-Oil-Air cooling (FOA) employs pumps to draw the oil out of the transformer tank to the external heat exchanger. Increasing of oil velocity also increases cooling efficiency and it reduces the top-oil temperature rise over bottom oil. There are two types of forced oil cooling, *non-directed flow* (NDFOA) and *directed flow* (DFOA). In non-directed flow transformers, the pumped oil from heat exchangers or radiators flows freely inside the tank. Directed flow transformers are designed so that the principal part of the pumped oil from the heat exchangers or radiators is forced to flow through the windings. Water-cooling can be used for large transformers when economically justified.

There exist some relationships between the air-cooled rating (OA) and the corresponding increase in rating due to the added cooling systems. For 3-phase transformers, assuming the average ambient temperature of 30°C, the multipliers are given below [6]. A 10 MVA (OA) transformer will have a rating of 10 x 1.25 = 12.5 MVA (OA/FA) rating at 55°C.

Transformer Size:

* ≤ 2.5 MVA, (FA)	= 1.15 (OA), one stage @ 55°C
* < 12 MVA, (FA)	= 1.25 (OA), one stage @ 55°C
* ≥ 12 MVA, (FA)	= 1.33 (OA), one stage @ 55°C
* ≥ 12 MVA, (FOA)	= 1.67 (OA), one stage @ 55°C
* ≥ 12 MVA, (FOA)	= 1.87 (OA), one stage @ 65°C

Oil Preservation Systems - During operation under heavy load, the transformer oil level will rise above the initial fill level. All oil-filled power transformer designs have some means of providing space for oil expansion. The most common designs employ the conservator tank or provide gas space (filled with inert gas) in the main transformer tank above the oil.

Auxiliary Cooling Equipment - A thermally operated control device or a manually operable switch can be used for control of auxiliary cooling equipment. The thermally operated control device, measuring the top-liquid temperature, is used in an automatic control system.

Auxiliary Devices - Transformers are also provided, in general, with the following auxiliary devices (common for 10MVA and larger), when requested during the procurement. Most of these devices are wired-up to the control cabinet for metering, monitoring, protection, and/or SCADA system application.

- Load Tap Changer [LTC] (± 16 x 5/8%)
- No-Load (or Off-load) Tap Changer [NLTC] (± 2 x 2½%)
- Bushing, CT's (1,2,3 per bushing)
- Top-Oil Thermometer
- Hottest-Spot Thermometer
- Oil-Level Indicator
- Oil-Flow Indicator
- Pressure-Vacuum Gauges
- Pressure Relay and Pressure-Relief Devices

2.2.2 Transformer Heating

Transformer heating is caused primarily by the core losses (no-load losses), winding (load) losses, and stray-load losses.

No-load Losses (Hysteresis and Eddy Current) - The no-load (or core) losses are comprised of primarily two components: Hysteresis and Eddy Current.

- *Hysteresis Loss:* The hysteresis loss happens due to the hysteretic nature of material. The hysteresis loss is given by the empirical formulae (Steinmetz),

$$P_h = k_h f B_m^x \text{(Volume)} \qquad (2.3)$$

where: k_h = Material constant
f = Frequency (Hz)
B_m = Maximum flux density (T =Wb/m^2)
x = Exponent varies between 1.6 – 2.8 (or sometimes higher), and
(Volume) = Volume of the magnetic material

- *Eddy Current Loss:* The alternating magnetic field in a transformer core causes current to flow in the core [eddy currents] and produce heat loss. This component of the core loss can be reduced by laminating. The eddy-current loss is proportional to the (lamination thickness)^2 and the loss can be expressed by the simplified equation:

$$P_e = k_e f^2 t^2 B_m^2 \text{(Volume)} \qquad (2.4)$$

where: k_e = Material constant
f = Frequency (Hz)
B_m = Maximum flux density (T =Wb/m^2)
t = Lamination thickness (mm), and
(Volume) = Volume of the magnetic material

If the transformer is over-excited, core loss increases because of the increased maximum flux density (B_m) and the non-linearities of the magnetization characteristic. However, for most common applications, the core loss is assumed to be constant.

Load (Winding) Losses - Load losses in transformers consist of two primary components: (1) *winding loss*, due to the copper (or aluminum) winding resistance, and (2) *stray load loss* due to the eddy currents induced in other structural parts of the transformer. The *winding loss* has two components: *resistance loss*, and *winding eddy-current loss.* In all cases the predominant component of the losses is proportional to the (current)^2 or (loading)^2.

The guaranteed load loss from manufacturers is specified at 85°C [7]. Unlike the IEEE/ANSI loading guide that uses 30°C average ambient temperature, all transformer losses are tested at 20°C ambient temperature. With 65°C winding rise, this will yield the 85°C test temperature. To evaluate this loss at any other temperature, the following corrections are required:

$$P_{CU@Tr} = P_{CU@85C}\left[\frac{T_k + T_r}{T_k + 85}\right] \tag{2.5}$$

$$P_{eddy@Tr} = P_{eddy@85C}\left[\frac{T_k + 85}{T_k + T_r}\right] \tag{2.6}$$

$$P_{stray@Tr} = P_{stray@85C}\left[\frac{T_k + 85}{T_k + T_r}\right] \tag{2.7}$$

Where, T_k is 234.5 for copper and 225 for aluminum. T_r is the new temperature.

2.2.3 Transformer Failure Modes

There are basically two major failure modes. They are:

Long-Term Failure - The dielectric strength of conductor insulation deteriorates slowly under normal loading. The three major contributing factors are: moisture content, amount of oxygen and heat cycle. Mechanical properties, such as, “Retained Tensile Strength (RTS)” and/or retained “Degree of Polymerization (DP)” are the most common criteria used to measure insulation integrity. Accelerated by heat, both the DP and RTS reduce over time. However, the “exact” end-of-life is unknown.

Short-Term Failure - This is attributed to “bubble formation” in the oil. The dielectric strength of the conductor insulation reduces drastically when bubble is generated. Three mechanisms are currently recognized for bubble formation: super-saturation of the oil, thermal decomposition of cellulose and vaporization of absorbed moisture. The thermal decomposition of cellulose during sudden large increase in load has been identified as the main cause.

2.3 Thermal Aging Principles and Historical Perspectives

Since the beginning of the use of power transformers, the conductor insulation has been made of some form of paper or cloth. The main constituent of these materials is cellulose, an organic c*ompound molecule made up of a long chain of g*lucose rings or monomers, typically ranging from 1400 to 1600 for new material. It has been established that, the mechanical strength of the fiber is closely related to the length of the chains (Degree of Polymerization, DP).

In 1930, Montsinger [7] did an insulation aging experiment by placing varnished cambric tape insulation into a series of oil-filled test tubes. The test tubes were heated and the insulation's tensile strength was measured. It was reported that the rate of deterioration of the tensile strength is doubled for each 5-10°C (approximately) increases in [continuous] operating temperature. The doubling factor was not a constant: about 6°C in the temperature range from 100-110°C and about 8°C for temperature above 120°C. However, a doubling factor as a constant of 8°C has been widely [and popularly] used in the industry. The present IEC Loading Guide uses a constant value of 6°C. Based on this research, the RTS of 50% of its initial value was also introduced (and later adopted by the IEEE) as the "end-of-life" criteria for insulation.

In 1948, Dakin [8] also made a significant advancement in defining insulation aging rate following a modification of Arrhenius' Chemical Reaction Rate Theory. According to this theory, the rate of change of a measured property can be expressed in the form of a reaction-rate constant R and can be expressed by:

$$R = A' e^{-B/T} \qquad (2.8)$$

Where, A' and B are empirical constants
T is the temperature in °Kelvin.

Dakin showed that all aging rate data (including Montsinger's) could fit into the Arrhenius Reaction Rate equation. This was later accepted widely by the technical community and become the foundation for determining the loss-of-insulation-life. From the reaction rate equation, the insulation life is now defined by:

$$L = A\, e^{B/T} \qquad (2.9)$$

Where, L is insulation life in either per-unit (or hours)
A is a constant, derived from the insulation life at 110°C hottest-spot temp.
B is the same aging rate slope defined in equation [7]

Many investigators have measured cellulose aging rates under controlled conditions and have presented their results. Some measured the RTS and others measured the DP or gas evolution rates. Investigators found and confirmed agreements between changes in RTS and DP. It was decided to select a single rate slope, the constant B, which is reasonably accurate for all forms of cellulose. Table 2.2[1] summarizes the results of such published literature. Placing the emphasis on the more modern data, a value of B of 15,000 is now used in the transformer insulation life curve utilized in the recent IEEE loading guide (C57.91-1995).

Table 2.2: Aging rate constant, *B*

Source, Year	Basis	B
Dakin, 1947	20% tensile strength retention	18,000
Sumner, 1953	20% tensile strength retention	18,000
Lawson, 1977	10% tensile strength retention	15,500
Lawson, 1977	10% DP	11,350
Head, 1979	Mechanical/DP/gas evolution	15,250
Shroff, 1985	250 DP	14,580
Goto, 1990	Gas evolution	14,300
ANSI-C57.92-1981	50% tensile strength retention	16,054
ANSI-C57.91-1981	Distribution transformer life test	14,594

2.4 Insulation Deterioration Mechanisms

As mentioned on numerous occasions three mechanisms contribute to cellulose deterioration in operating transformers, namely *hydrolysis, oxidation, and pyrolysis*. The agents responsible are water, oxygen, and heat, respectively.

Hydrolysis (Water) - The oxygen bridge between glucose rings is affected by water, causing the rupture of the chains, and reduction of DP and weakening of fiber.

Oxidation (Oxygen) - Oxygen attacks the carbon atoms in the cellulose molecule to form aldehydes and acids, releasing water, CO, and CO_2. Since oxidation releases water, it helps accelerate the hydrolysis mechanism and the insulation deterioration. Oxygen is derived from either the atmosphere, or from the thermal degradation of cellulose. The problem is worsened by the presence of *catalysts* and *accelerators* like moisture and copper.

Pyrolysis (Heat) - Heat and the resulting high temperature will contribute to the breakdown of individual monomers in the cellulose chain. Thermal degradation of the cellulose also yields free water, as well as certain gases like carbon monoxide *(CO)* and carbon dioxide (CO_2). High temperature within a power transformer can cause the cellulose insulation to shrink and become brittle. This leaves the solid insulation susceptible to failure due to mechanical stress.

2.5 Transformer Life vs. Insulation Life

If an end-point of insulation life is to be defined, it must be done in terms of some measurable physical characteristic properties. This could be mechanical (RTS), chemical (DP) or electrical (dielectric strength) properties. Insulation dielectric strength is found to deteriorate slowly if insulation is not mechanically disturbed and bubbles are not present. Initially a mechanical property “RTS” was chosen. Later, the “DP” is also accepted as another popular alternative. A number of end-of-life criteria have been suggested in the literature, namely 50% [20% suggested by others] RTS, and 200 DP. The DP of 200 which is equivalent to 20% retained tensile strength seems to be the most preferable. The direct measurement, when possible, of the RTS or DP on paper sample retrieved from transformer is the accurate method. However, removal of paper insulation is expensive and in many cases impractical.

Reference [10] published the results of RTS and the DP of thermally upgraded paper aged in a sealed tube at 160°C. These results are plotted in Figure 2.2 and Figure 2.3 and are utilized in this research for estimating the remaining life expectancy.

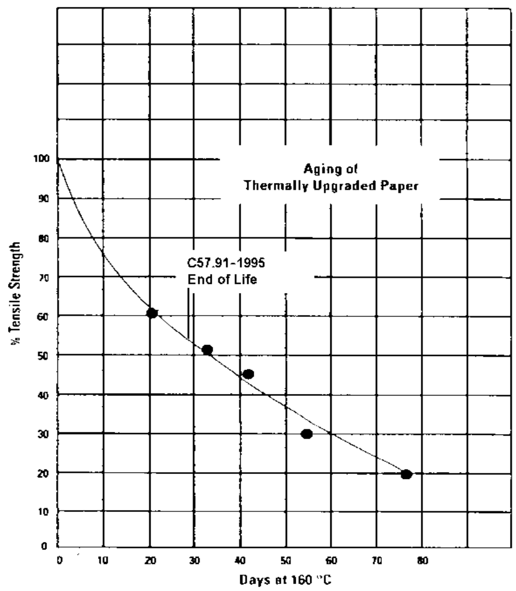

Figure 2.2: Tensile strength reduction

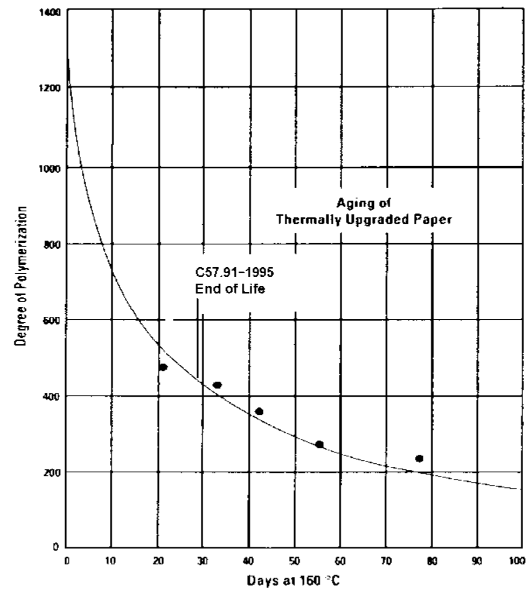

Figure 2.3: Degree of Polymerization Reduction

The 20% RTS and the DP of 200 is used as end-of-life criteria. The time (t) is in per-unit life. The data were fit to the exponential curve by the least square method. The tensile strength curve then can be written as [11]:

$$\textit{Retained Tensile Strength (RTS)} = 97.05e^{-1.58t} \tag{2.10}$$

For degree of polymerization, the equation is given by:

$$\textit{Retained DP (DP)} = 622e^{-1.135t} \tag{2.11}$$

The remaining life in per-unit (1-t) can be derived from the following equations:

$$\textit{Remaining Life} = 1 + 0.633\ln\left(\frac{RTS}{97.05}\right) \tag{2.12}$$

$$Remaining\ Life = 1 + 0.881\ln\left(\frac{DP}{622}\right) \qquad (2.13)$$

Where, RTS is the remaining tensile strength, and
DP is the remaining degree of polymerization

Equation (2.12) and **Error! Reference source not found.** are plotted in Figure 2.4 and Figure 2.5. Corresponding to % RTS of 20 or DP of 200, the remaining life is zero. If the transformer is functional beyond these criteria, the transformer has exceeded its expected life and this is denoted by the negative sign.

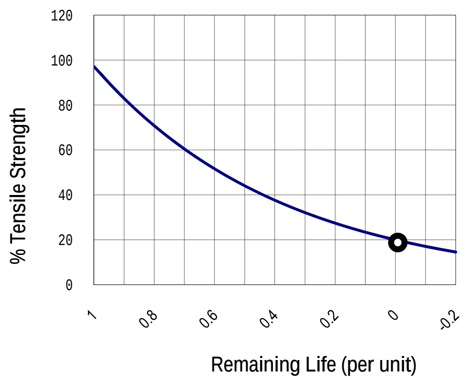

Figure 2.4 Remaining life by tensile strength method

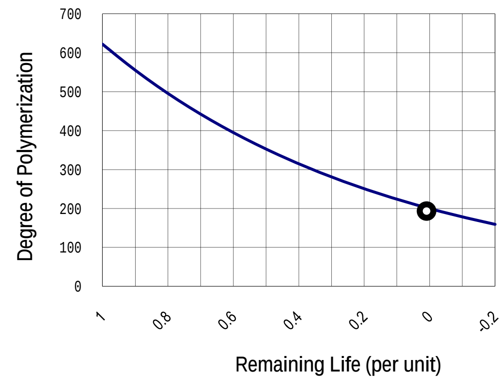

Figure 2.5 Remaining life by degree of polymerization method

The ANSI/IEEE Std. C57.92[12] offers the end-of-insulation-life criteria of 65,020 hours for 50% RTS of insulation at 110°C hottest-spot temperature. This is based on low oxygen and a moisture level of 0.5%. Table 2.3[12] shows the normal insulation life at various levels of moisture and oxygen. The higher water content reduces (by a factor of 2 for doubling the water content) the normal insulation life as:

$$Normal\ Life = \frac{Normal\ Life\ @[0.5\% H_2O]}{2 \cdot [\% H_2O]} \qquad (2.14)$$

Table 2.3: Insulation Life Definitions

Basis	Water Content	Oxygen Level	Life Hours
50% Tensile	**0.5%**	**Low**	**65,020***
	1.0%	Low	32,510
	2.0%	Low	16,255
	0.5%	High	26,000
	1.0%	High	13,000
	2.0%	High	6,500
20% Tensile	**0.5%**	**Low**	**152,000**
	1.0%	Low	76,000
	2.0%	Low	38,000
	0.5%	High	60,800
	1.0%	High	30,400
	2.0%	High	15,200
200 DP	**0.5%**	**Low**	**158,000**
	1.0%	Low	79,000
	2.0%	Low	39,000
	0.5%	High	63,200
	1.0%	High	31,600
	2.0%	High	15,800

* ANSI/IEEE Std. C57.92's end-of-life criteria

2.6 Overloading Limitation

Although transformers are overloaded, there are some limits.

2.6.1 Hottest-Spot Limits

The winding hottest-spot temperature at the top of the high or low voltage winding is the most critical parameter. It determines the loss-of-life and indicates the potential risk of releasing gas bubbles on a severe sudden overload condition.

If loss-of-life (of the solid insulation) is not tracked closely, the recent IEEE loading guide [1] suggests a maximum continuous hottest-spot winding temperature limit of 140^{o}C (with some loss-of-life), which is the limiting temperature for long-term emergency loading. During short-term emergency situations, hottest-spot temperature is allowed to exceed 140^{o}C.

2.6.2 Top-Oil Limits

Due to convection and nature of cooling system design, the highest oil temperature in the transformer tank will be at the top-oil region. When the top-oil temperature exceeds

105°C, it is possible for oil to expand beyond the tank capacity and causes the pressure relief device to operate. Upon cooling, the reduced volume of oil may expose electrical parts, including the bushing and the winding. Higher top-oil temperatures approaching flash-point value of 145°C[13,14] pose a much greater danger of sudden ignition and explosion. IEEE recommends that the top-oil temperature under any overloading should not exceed 110°C.

2.6.3 Insulation Life

Insulation loss-of-life of power transformers is closely related to a time function of temperature, moisture, and oxygen content. From these parameters, the most significant determining factor to insulation deterioration is the temperature reached by the hottest-spot in the winding.

2.6.4 Ancillary Equipment

Overloading the transformer can have significant detrimental effects on associated equipment. The bushings, tap-changers, bushing-type current transformers (BCT's) and leads may also be affected by the increased temperature.

Bushings are designed for a hottest-spot temperature of 105°C for a normal top-oil temperature limit of 95°C. Operating the bushing above these limits can have damaging effects such as internal pressure buildup, aging of gasket material, bubble formation when the hottest-spot temperature exceeds 140°C. For bushings, the following guidelines[6] are recommended:

- Transformer top-oil temp 110°C maximum
- Maximum [continuous] current 2 x rated bushing current
- Bushing insulation hottest-spot temp 150°C maximum

Tap changers, whether designed to change taps under load (LTC's) or de-energized conditions, are subjected to carbon build-up at elevated temperatures. Transformers are normally designed so that the LTC rating is greater than the transformer rating. It has been seen from practice that, more frequent maintenance is required on LTC's, which are subjected to operation at elevated temperatures compared to transformers running at lower temperature.

Bushing-type current transformers (BCT's) have the transformer top-oil as their ambient temperature. Overloading the transformer will result not only in higher top-oil temperature, but higher BCT's secondary current as well. The manufacturer should be consulted regarding the BCT's capability, if the transformer is loaded beyond its rating.

2.6.5 Stray Flux Heating

Stray flux produces localized heating in any metallic part. This heating results from induced eddy-current losses, harmonics losses, and some hysteresis losses. Under extreme conditions of transformer overvoltage, stray flux increases disproportionately due to core saturation.

Various methods for stray flux control include the use of insulated (non-metallic) supports at the top and bottom of the coil windings, vertical core-clamp configurations, special non-magnetic supports for LV bushings and BCT's associated with high-current leads, and tank wall shields. Stray flux can also be controlled in a magnetic circuit design.

2.6.6 Bubble Generation

Gas bubbles[13-23] within transformer oil are of a serious concern, since the dielectric strength of the gases is significantly lower than the dielectric strength of the oil or the cellulose insulation. Bubbles can form in the transformer from gas generated during faults or from sudden overloading. The generated gas tends to re-dissolve after a long period of time (approx. 20 hours[21].

Three mechanisms [23,24] are known by which gas can generate bubbles. IEEE recommends the absolute upper limit of 180°C winding hottest-spot temperature.

- Super-saturation of the oil with a blanket gas.
- Thermal decomposition of cellulose insulation.
- Vaporization of absorbed moisture in the cellulose.

2.7 Transformer Design Optimization

There are various optimization objectives one can identify, such as, minimize optimization of unit cost, maximize efficiency, minimize the total life cycle owning cost, and meet the guaranteed losses. The number of variables changes according to these design objectives. Usually, computer aided design tools are necessary to efficiently solve this multi-variable problem.

2.7.1 Design for Maximum Efficiency

Maximum efficiency occurs in a transformer at a pu loading (K), when the winding loss ($K^2 P_{cu@FL}$) is equal to the core loss (constant). Mathematically,

$$K^2 P_{cu@FL} = P_{core}$$

$$\frac{1}{K^2} = \frac{P_{cu@FL}}{P_{core}} = \text{loss ratio (R)} \qquad (2.15)$$

Where, $P_{cu@FL}$ is the winding loss at full load
P_{core} is the core loss at rated voltage

The loss ratio indicates the loading point that yields maximum efficiency. The typical value of loss ratio varies between 4-8. The loss ratio of 4 and 8 corresponds to 0.5 and 0.35 per-unit loading (*K*) respectively for maximum efficiency.

2.7.2 Design for Minimum Cost of Material

Variations on material costs between different designs are determined mainly by the proportion of iron core and copper in the transformer. Depending on the relative costs of these materials, an optimum mass ratio for minimum cost can be obtained. It has been shown [5] that for the minimum cost of materials, the cost of the copper is equal to the cost of core. In term of specific cost per-unit mass ($/lb), the mass ratio is equal to,

$$\frac{Core\ Mass\ (lb)}{Copper\ Mass\ (lb)} = \frac{Copper\ Cost\ per\ pound\ (\$ / lb)}{Core\ Cost\ per\ pound\ (\$ / lb)} \qquad (2.16)$$

The typical cost ratio of copper and silicon-steel core is 3 to 1. It has been found that for large transformer designs, a good correlation exists between the actual and optimum value of cost ratio. However, in secondary transmission, distribution units, the actual cost ratios are higher and the mass ratios are lower than optimum, indicating that the amount of copper relative to iron is greater than that required for minimum cost of material.

2.7.3 Design for Minimum Total Owning Cost (TOC)

The engineers traditionally determine the cost effectiveness by calculating the values of the no-load and load losses. These are often referred to as the "*A*" and "*B*" factors. They are multiplied by no-load and load losses respectively and applied to the total owning cost (TOC),

$$TOC = NLL * A + LL * B + C \qquad (2.17)$$

Where, *NLL* is the no-load loss in kW,
A is the capitalized cost per kW of *NLL* (*A* factor),
LL is the load loss in kW at the transformer's rated load,
B is the capitalized cost per kW of *LL* (*B* factor),
C is the initial cost of the transformer including transportation, sales taxes, and other costs to prepare it for service.

The average values of A and B used in the US is $3,430 and $1,090 per kW, respectively. The transformer that meets the transformer purchaser's technical specification with the lowest total owning cost becomes the most cost-effective transformer.

2.8 Transformer Monitoring and Diagnostics

It is of utmost importance for all electric utilities to minimize the overall cost of running the electric power systems while maintaining an overall reliable and robust electrical system. The power transformers are one of the most expensive and critical elements in a power system. Cost saving can be realized through a delay in the replacement of transformers and a reduction in maintenance effort. Well designed monitoring systems for power transformers can help achieve these aims. A catastrophic failure, sudden and unplanned outage of a transformer is associated with considerable costs that include loss in produced energy, process down-time, and penalties. The repair costs normally are very expensive. With modern technology, it is possible to monitor a large number of parameters. The economic constraints make it useful to differentiate between "Monitoring" and "Diagnostics". *Monitoring* is here defined as on-line collection of data, sensor development and development of methods for condition measurement of power transformers. *Diagnostics* contains interpretation of data, but also all off-line measurements.

2.8.1 On-Line Monitoring

There are a number of on-line monitoring devices available in the market:

- *Dissolved Gas-in-Oil Analysis (DGA):* The gas-in-oil analysis is the most important feature of an online monitoring system for condition assessment. In cases of overheating, partial discharge or local breakdown inside the transformer, several gases are produced and dissolved in the oil. If a certain generation rate of gas is exceeded, gas bubbles arise. The most important transformer fault gases are H_2, CO, CO_2, CH_4, C_2H_2, C_2H_4 and C_2H_6. In every case of an internal fault, H_2 will be produced. The content of individual gases depends on the kind of fault. IEEE C57.104-1991[25] specifies the interpretation of gases generated in oil. There are two types of gas sensors commercially available. (i) The semiconductor sensor [26] that detects only H_2 or a composition of H_2, and (ii) More complex sensors can detect several or all of these gases. These are based on infrared technology or gas chromatography [27,28]

- *Moisture Content:* Increases in the moisture levels of the oil indicate that there is a possible rupture or faulty seal in the tank. Excessive moisture increases the electrical conductivity of the transformer oil and aging rate of insulation.

- *Partial Discharge:* There are a couple of methods to detect partial discharge. One is through a high frequency current transformer connected to the transformer neutral and a capacitive voltage coupler. These sensors detect an impulse due to partial discharge and discriminate between internal and external partial discharge. Another method is by an acoustic signal. The ultrasonic transducers are used as acoustic detection device located outside the main tank.

- *Load Tap Changer (LTC) Monitoring:* Transformers with LTC have generally higher failure rate. The mechanical and electrical failures (springs, bearings, shafts, drive mechanisms, transition resistors, insulation and contacts) of LTC ranks high. Three simple measurements can be used to monitor faults in LTC. These are measurement of motor current measurement, temperature different between the LTC compartment and main tank, and acoustic technique.

- *Temperature:* The hottest-spot of the winding is the main limiting factor. Conventional temperature measurements using thermometers or thermocouples are not a direct hottest-spot measurement. However top-oil temperature is an approximate indicator for hottest-spot temperature. A hottest-spot thermometer is an optional device. A current proportional to the winding current is supplied to the heater from current transformer in the winding in which the hottest-spot is to be measured. Fiber optic sensors can be installed in the winding when the transformer is manufactured. Two types of sensors have been used, fibers which measure the temp. in one point, and distributed fibers which measure the temperature along the length of the fiber.

- *Oil Conductivity:* This is accomplished by using a porous ceramic sensor and electrodes and analyzing the sensor's leakage current.

2.8.2 Off-Line Diagnostics

A number of "Off-Line Diagnostics" schemes for transformer health monitoring have been in existence for a long period of time including[29].

1) Gas-in-Oil or Dissolved Gas Analysis (DGA)
2) Partial Discharge (PD)
3) Degree of Polymerization (DP)
4) Furanic Compounds Analysis
5) Thermography
6) Frequency Response Analysis
7) Leakage Inductance
8) Dielectric Response Oil Analysis

3. Transformer Thermal Models, Overloading, and Loss-of-Insulation-Life

Transformer's overall life expectancy and overloading capabilities depend on several factors. However, it is determined primarily by the winding hottest-spot temperature. The overloading guideline and the corresponding loss-of-life calculation as presented in the ANSI/IEEE C57.91-1995 [1] is discussed here. Reference to the IEC Guide [2] is available in the Appendix.

3.1 IEEE "Classical Thermal Model" (Clause 7)

ANSI/IEEE C57.91, is based on average characteristics of a wide range of transformer ratings and designs. The guide uses the top-oil rise and the hottest-spot conductor rise over top-oil to calculate the hottest-spot temp..and is defined by:

$$T_{HS} = T_A + \Delta T_{TO} + \Delta T_G \tag{3.1}$$

Where, T_A is the ambient temperature

ΔT_{TO} is the top-oil rise over the ambient temperature, and

ΔT_G is the winding hottest-spot temperature rise over top-oil temperature.

Figure 3.1 shows corresponding thermal diagram. The assumptions are::

- The oil temperature inside the windings increases linearly from bottom to top of the winding regardless of the cooling type,
- The temperature rise of conductor at any position up the winding increases linearly and parallel to the oil temperature rise,
- The hottest-spot temperature rise is higher than the temperature rise of the conductor at the top of the winding, because of the increase in stray losses. To find hottest-spot temperature, the hottest-spot allowance (ΔT_G) is added to the top-oil temperature.

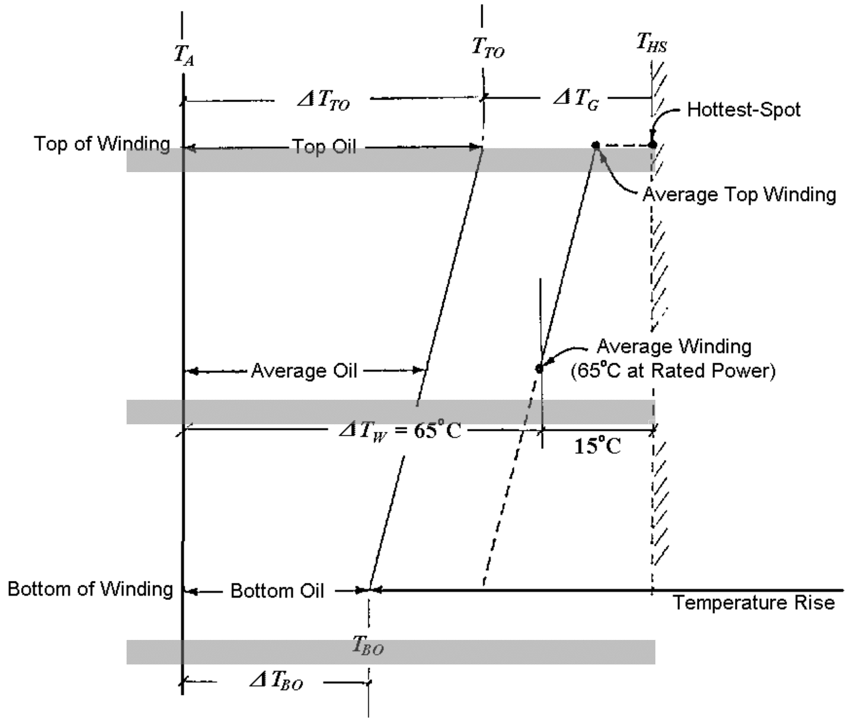

Figure 3.1 Transformer's temperature profile for IEEE classical thermal model

The top-oil temperature rise under steady-state condition is proportional to the total transformer loss and given by:

$$\Delta T_{TO} = \Delta T_{TOR} \cdot (P_T)^n = \Delta T_{TOR} \cdot \left(\frac{P_{loss}}{P_R}\right)^n = \Delta T_{TOR} \cdot \left(\frac{K^2 R + 1}{R + 1}\right)^n \qquad (3.2)$$

$$K = \frac{I}{I_R} = \frac{\text{Actual load (MVA)}}{\text{Rated load (MVA)}} = \text{Per - Unit Loading}$$

where: ΔT_{TOR} is the top-oil temperature rise at rated load
P_T is the per-unit transformer losses
P_{loss} are the total losses in watts
P_R is the total losses at rated load
K is per-unit loading
R is the loss ratio and n is an exponent (oil).

The rated condition refers to maximum (highest) rating (rating at 65°C average winding temperature rise for transformers with thermally upgraded insulation)

The winding hottest-spot temperature rise over top-oil temperature is given by:

$$\Delta T_G = \Delta T_{GR} \cdot (K^2)^m \quad (3.3)$$

where: ΔT_{GR} is the winding hottest-spot temp. rise over top-oil temp. at rated load
K^2 is the per-unit winding loss, and
m is an exponent (winding).

The IEEE standard recommends the use of imbedded detector for measuring ΔT_{GR}, the winding hottest-spot temperature rise over top-oil temperature at rated load. An alternate approach is to add a fixed value over the average winding rise given by:

$$\Delta T_{GR} = \text{average winding rise over top oil} + 15^{\circ}\text{C}$$

$$\Delta T_{GR} = (\Delta T_{WR} - \Delta T_{TOR}) + 15^{\circ}\text{C} \quad (3.4)$$

Where, ΔT_{WR} is average winding temperature rise at rated load.
ΔT_{GR} is calculated from average winding rise over top-oil temperature rise plus 15°C corresponding to 65°C winding rise respectively.

Figure 3.1 illustrates the relationships. Table 3.1 also provides the necessary limits of the design values for oil-cooled transformer

Table 3.1: Thermal characteristics of classical thermal model at rated load (indicated by suffix *R*), IEEE Std. C57.91-1995

		Cooling System				
		OA	FA <133%	FA >133%	NDFOA	DFOA
Hottest spot rise	ΔT_{HSR}	80	80	80	80	80
Top oil rise	ΔT_{TOR}	55	50	45	45	45
Oil time constant	τ_{TOR} (hr)	3.0	2.0	1.25	1.25	1.25
Winding time constant	τ_{GR} (min)	5.0	5.0	5.0	5.0	5.0
Loss ratio	R	3.2	4.5	6.5	6.5	6.5
Oil exponent	n	0.8	0.9	0.9	1.0	1.0
Winding exponent	m	0.8	0.8	0.8	0.8	1.0

Equations 3.2 and 3.3 are steady-state solutions. In order to find transient solution for the top-oil temperature, the energy balance equation is used

Energy Generated = Energy Radiated + Energy Absorbed

The differential equation for the top-oil temperature rise may be written as [31]

$$P_{loss}\,dt = k\Delta T_{TO}\,dt + C\,d\Delta T_{TO} \tag{3.5}$$

where: P_{loss} is the total losses in the transformer in watts
k is the radiation constant in $\mathrm{W/^\circ C}$
C is the transf. thermal capacity in $\mathrm{Watt\text{-}min./^\circ C}$, and can be calculated from the empirical relationship: C = 0.06 * (weight of core and coil assembly in pounds) + 0.04 * (weight of tank and fitting in pounds) + 1.33 * (gallons of oil);

Equation (3.5) can be rewritten as

$$\frac{C}{k}\frac{d\Delta T_{TO}}{dt} = -\Delta T_{TO} + \frac{P_{loss}}{k}$$

$$\tau_{TO}\frac{d\Delta T_{TO}}{dt} = -\Delta T_{TO} + \frac{P_{loss}}{k} \tag{3.6}$$

Where, τ_{TO} is the oil time constant and defined by the ratio of C and k.

From energy balance equation (3.5), $d\Delta T_{TO}$ is equal to zero at steady-state. The subscript u in ΔT_{TO} denotes the ultimate temperature. This gives

$$P_{loss} = k\Delta T_{TO,u} \text{ or } \frac{P_{loss}}{k} = \Delta T_{TO,u} = \Delta T_{TOR}\cdot\left(\frac{K^2R+1}{R+1}\right)^n$$

Equation (3.6) then becomes, (the subscript i in ΔT_{TO} denotes the initial temperature).

$$\tau_{TO}\frac{d\Delta T_{TO}}{dt} = -\Delta T_{TO} + \Delta T_{TO,u} \tag{3.7}$$

$$\Delta T_{TO}(0) = \Delta T_{TO,i}$$

The solution of the differential equation (3.7) is

$$\Delta T_{TO} = (\Delta T_{TO,u} - \Delta T_{TO,i})(1 - e^{-t/\tau_{TO}}) + \Delta T_{TO,i} \tag{3.8}$$

The oil time constant (τ_{TO}) in equation (3.6) to (3.8) can be written as

$$\tau_{TO} = \frac{C}{k} = C\,\frac{(\Delta T_{TO,u} - \Delta T_{TO,i})}{\Delta P_{loss}}$$

The subscript *u* and *i* denote for ultimate and initial values, respectively. The value of the oil time constant (τ_{TO}) varies with the top-oil temperature rise and power losses. The manufacturer usually provides the oil time constant at rated load, and is given by:

$$\tau_{TOR} = C\,\frac{\Delta T_{TOR}}{P_R}$$

$$k = \frac{(\Delta P_{loss,u} - \Delta P_{loss,i})}{(\Delta T_{TO,u} - \Delta T_{TO,i})}$$

The oil time constant at any load (τ_{TO}) can then be expressed in terms of the corresponding value at rated load by the following equation 3.9):

$$\tau_{TO} = \frac{\tau_{TOR}}{\Delta T_{TOR}} * \frac{\Delta T_{TO,u} - \Delta T_{TO,i}}{(\Delta P_{loss,u} - \Delta P_{loss,i})/P_R} = (\tau_{TOR})\,\frac{\left(\dfrac{\Delta T_{TO,u}}{\Delta T_{TOR}}\right) - \left(\dfrac{\Delta T_{TO,i}}{\Delta T_{TOR}}\right)}{\left(\dfrac{\Delta T_{TO,u}}{\Delta T_{TOR}}\right)^{\frac{1}{n}} - \left(\dfrac{\Delta T_{TO,i}}{\Delta T_{TOR}}\right)^{\frac{1}{n}}} \qquad (3.9)$$

With the hottest-spot winding temperature rise over top-oil temperature being proportional to the transformer winding loss, the corresponding initial and ultimate temperature rise are given by

$$\Delta T_{G,i} = \Delta T_{GR} \cdot (K_i^2)^m$$

$$\Delta T_{G,u} = \Delta T_{GR} \cdot (K_u^2)^m \qquad (3.10)$$

Where, *m* is winding exponent. Similar to oil time constant derivation, winding time constant (τ_{GR}) can be derived as:

$$\tau_{GR} = M_W C_{PW} \frac{\Delta T_{GR}}{P_{WR}}$$

$$\tau_G = (\tau_{GR}) \frac{\left(\frac{\Delta T_{G,u}}{\Delta T_{GR}}\right) - \left(\frac{\Delta T_{G,i}}{\Delta T_{GR}}\right)}{\left(\frac{\Delta T_{G,u}}{\Delta T_{GR}}\right)^{\frac{1}{m}} - \left(\frac{\Delta T_{G,i}}{\Delta T_{GR}}\right)^{\frac{1}{m}}} \quad (3.11)$$

Where: M_W is winding mass, C_{PW} is specific heat of winding material, and P_{WR} is the winding loss at rated load. The winding hottest-spot rise over top-oil differential equation is written as:

$$\tau_G \frac{d\Delta T_G}{dt} = -\Delta T_G + \Delta T_{G,u} \quad (3.12)$$

The solution of the differential equation (3.12) is

$$\Delta T_G = (\Delta T_{G,u} - \Delta T_{G,i})(1 - e^{-t/\tau_G}) + \Delta T_{G,i} \quad (3.13)$$

As the hottest-spot time constant is very short (between 5-10 minutes) compared to the top-oil value (1-3 hours), the hottest-spot conductor rise can be approximated as in equation (3.10) by

$$\Delta T_G \approx \Delta T_{GR} \cdot (K^2)^m$$

IEEE "Clause 7" thermal model has some limitations. The model does not include the behavior of oil in cooling duct and results in higher hottest-spot temperature. The model also ignores the time delay due to the ambient temperature change (ΔT_A). The modified top-oil temperature equation by adding ambient temperature variation [31] into the top-oil temperature equation is:

$$\tau_{TO} \frac{d\Delta T_{TO}}{dt} = -\Delta T_{TO} + \Delta T_{TO,u} + \Delta T_A \quad (3.14)$$

The above equation and zero initial conditions and rearrangement yields

$$\Delta T_{TO}(s) = \frac{1}{1+\tau_{TO}s} \cdot \Delta T_{TO,u}(s) + \frac{1}{1+\tau_{TO}s} \cdot \Delta T_A(s) \qquad (3.15)$$

The solution can be obtained by numerical method from the block diagram shown below (Figure 3.2). The unmodified model gave large error (5°C error for 10°C daily ambient temperature variation).

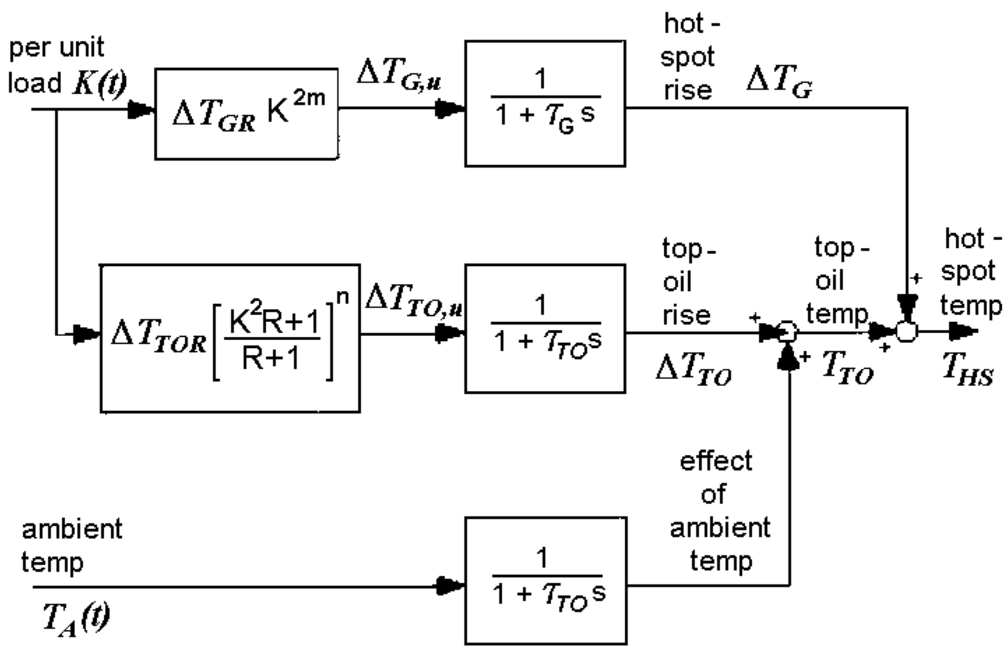

Figure 3.2: Block diagram of the modified transient heating equations

3.2 IEEE Alternate Thermal Model (Annex G)

The IEEE Classical model uses the top-oil temperature rise over ambient temperature to calculate the winding hottest-spot temp. Recent investigations [33,34] have shown that during overloads the temperature of the oil in the winding cooling ducts rises rapidly at a time constant equal to that of the winding (contrary to the oil). During this transient condition (as shown in Figure 3.3), the oil temperature adjacent to the hottest-spot location is higher than the top-oil temperature in the tank. The calculations in Annex G are based on Pierce[34] and account for the type of fluid, cooling mode, winding duct oil temperature rise, resistance and viscosity changes, stray losses, eddy current losses, hottest-spot location, ambient temperature, and load changes.

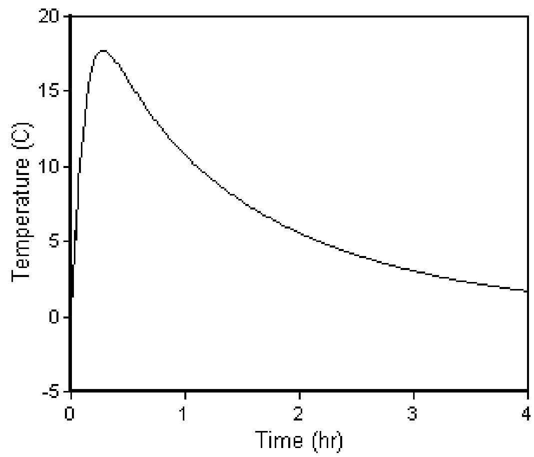

Figure 3.3: Variation of duct oil temperature and top-oil temperature after a load step 0-100% with an ambient temperature of (-10°C)

The principle of the model is governed by two basic heat transfer equations:

Heat balance equation: $Q_{GEN} = Q_{ABS} + Q_{LOST}$

Where, Q_{GEN} is heat generated by heat sources, Q_{ABS} is heat absorbed in heat sources, and Q_{LOST} is the heat lost to cooling medium.

And heat absorption equation: $Q_{ABS} = M \cdot C_P \cdot \Delta T$

Where, M is the mass of absorbed material and C_P is the specific heat of material, and ΔT is the temperature difference.

The hottest-spot temp. of the model is made up of the following components:

$$T_{HS} = T_A + \Delta T_{BO} + \Delta T_{WO} + \Delta T_{HS/WO} \qquad (3.16)$$

Where, ΔT_{BO} is bottom-oil rise over ambient,

ΔT_{WO} is duct-oil rise at winding hottest-spot location over bottom-oil,

$\Delta T_{HS/WO}$ is winding hottest-spot rise over adjacent duct-oil temperature at hottest-spot location.

The calculation consists of a number of iterations of small time interval, Δt. All variables are updated for every iteration. All equations use actual temperature, and not the temperature rise.

3.2.1 Duct-oil temperature

Within the winding, the heat generated, absorbed and lost by the winding is defined by:

$$Q_{WGEN} = K^2 (T_{KW} P_{WR} + P_{ER} / T_{KW}) \Delta t$$

$$Q_{WLOST} = \left(\frac{T_W - T_{DAO}}{T_{WR} - T_{DAOR}} \right)^{5/4} \left(\frac{\mu_{WR}}{\mu_W} \right)^{1/4} (P_{WR} + P_{ER}) \Delta t \qquad \text{For OA,FA,NDFOA}$$

$$Q_{WLOST} = \left(\frac{T_W - T_{DAO}}{T_{WR} - T_{DAOR}} \right) (P_{WR} + P_{ER}) \Delta t \qquad \text{; for DFOA}$$

$$Q_{WGEN} - Q_{WLOST} = Q_{WABS} = M_W C_{PW} \Delta T_W \qquad (3.17)$$

where: Q_{WGEN} , Q_{WABS} , and Q_{WLOST} is the heat generated, absorbed and lost in time interval (Δt).

K is the transformer loading in per-unit.
T_{KW} is the winding resistance correction factor.
P_{WR} and P_{ER} are the winding and eddy current losses at rated load.
T_W is the average winding temperature.
T_{WR} is the average winding temperature at rated load.
T_{DAO} is the average duct-oil temperature.
T_{DAOR} is the average duct-oil temperature at rated load.
μ_W is oil viscosity in the duct.
μ_{WR} is oil viscosity in the duct at rated load.
M_W is mass of the winding.
C_{PW} is the specific heat of the winding.

The new value of the average winding temp. is calculated from ΔT_W from (3.17).

$$T_{W,new} = T_{W,old} + \Delta T_W \qquad (3.18)$$

The duct-oil temperature rise is given by

$$\Delta T_{TDO/BO} = (T_{TDOR} - T_{BOR}) \left(\frac{Q_{WLOST}}{(P_{WR} + P_{ER}) \Delta t} \right)^x \qquad (3.19)$$

Where, $\Delta T_{TDO/BO}$ is the duct-oil temperature rise over bottom-oil temperature, T_{TDOR} and T_{BOR} is the top-duct oil and bottom-oil temperature, and x is exponent of duct-oil rise (0.5 for OA, FA, NDFOA and 1.0 for DFOA)

The duct-oil temperature rise gives the update to T_{TDO}, T_{DAO}, and T_{WO} as

$$T_{TDO} = T_{BO} + \Delta T_{TDO/BO}$$

$$T_{DAO} = (T_{TDO}+T_{BO})/2$$

$$T_{WO} = T_{BO} + HHS \cdot \Delta T_{TDO/BO}$$

Where, HHS is the location of hottest temperature of the winding. It is equal to 1.0 when the hottest-spot is at the top of winding and equal to 0.0 when at the bottom.

3.2.2 Hottest-spot temperature

In finding the hottest-spot temperature, it is assumed that the entire winding is at the hottest-spot temperature. The winding loss at hottest-spot temperature is

$$P_{WHSR} = T_K P_{WR}$$

$$T_K = \frac{234.5 + T_{HSR}}{234.5 + T_{WR}} \text{ for Cu winding and}$$

$$T_K = \frac{225 + T_{HSR}}{225 + T_{WR}} \text{ for Al winding}$$

where P_{WHSR} is the winding loss at hottest-spot temperature, T_K is the temperature correction factor, T_{HSR} is the hottest-spot temperature at rated load.

Similar to the duct-oil temperature, within the winding at hottest-spot location, the heat generated, absorbed and lost by the winding is defined as

$$Q_{HSGEN} = K^2 (T_{KHS} P_{WHSR} + P_{EHSR} / T_{KHS}) \Delta t$$

$$Q_{HSLOST} = \left(\frac{T_{HS} - T_{WO}}{T_{HSR} - T_{WOR}}\right)^{5/4} \left(\frac{\mu_{HSR}}{\mu_{HS}}\right)^{1/4} (P_{WHSR} + P_{EHSR})\Delta t \qquad \text{; for OA,FA,NDFOA}$$

$$Q_{HSLOST} = \left(\frac{T_{HS} - T_{WO}}{T_{HSR} - T_{WOR}}\right)(P_{WR} + P_{ER})\Delta t \qquad \text{; for DFOA}$$

$$Q_{HSGEN} - Q_{HSLOST} = Q_{HSABS} = M_W C_{PW} \Delta T_{HS} \tag{3.20}$$

Where: Q_{HSGEN} , Q_{HSABS} , and Q_{HSLOST} is the heat generated, absorbed and lost in time (Δt).
T_{KHS} is the winding resistance correction factor.
P_{HSR} and P_{EHSR} are the winding and eddy current losses at rated load at hot test-spot temp.
T_{HS} is the hottest-spot temperature.
T_{HSR} is the hottest-spot temperature at rated load.
μ_{HS} is the oil viscosity at hottest-spot location.
μ_{HSR} is the oil viscosity at hottest-spot location at rated load.

The new value of hottest-spot temperature is calculated from ΔT_{HS} of equation (3.20)

$$T_{HS,new} = T_{HS,old} + \Delta T_{HS} \tag{3.21}$$

3.2.3 Bulk-oil temperature

The model considers the heat that is generated, absorbed, and lost (to the air)

$$Q_{OGEN} = Q_{WLOST} + Q_{Stray} + Q_{Core}$$

$$Q_{OLOST} = \left(\frac{T_{OAVG} - T_A}{T_{OAVGR} - T_{AR}}\right)^{1/y} P_{TR}\Delta t$$

$$Q_{WLOST} + Q_{Stray} + Q_{Core} - Q_{OLOST} = \Sigma MC_P \cdot \Delta T_{OAVG} \tag{3.22}$$

where: Q_{OGEN} , Q_{WLOST} , Q_{Stray} , Q_{Core} , and Q_{OLOST} is the heat generated in oil, heat lost form winding to oil, stray loss heat, core loss heat, and the heat lost.
T_{OAVG} is the average bulk-oil temperature, (T_{TO}+T_{BO}) /2.
T_{OAVGR} is the average bulk-oil temperature at rated load.
y is the exponent of average oil rise (See Table 3.2)

P_{TR} are the total transformer losses at rated load.
ΣMC_P is the summation of the product of mass and specific heat of tank, core, and oil excluding winding.

Table 3.2: Summary of exponents

Exponent		OA	FA	NDFOA	DFOA
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	0.5	0.5	1.0	1.0

The new value of the average bulk oil temp. is calculated from ΔT_{OAVG} Equation (3.22)

$$T_{OAVG,new} = T_{OAVG,old} + \Delta T_{OAVG} \qquad (3.23)$$

The top- and bottom-oil temperature difference is given by:

$$\Delta T_{TO/BO} = (T_{TOR} - T_{BOR})\left(\frac{Q_{OLOST}}{P_{TR} + \Delta t}\right)^z \qquad (3.24)$$

Where, $\Delta T_{TO/BO}$ is top- and bottom-oil temperature difference,
T_{TOR} and T_{BOR} is top-oil and bottom-oil temperature, and
z is exponent of top-oil to bottom-oil rise in radiator (0.5 for OA, FA and 1.0 for NDFOA, DFOA).

The top- and bottom-oil temp. difference gives the update to T_{TO} and T_{BO} as

$$T_{TO} = T_{OAVG} + \Delta T_{TO/BO}/2$$

$$T_{BO} = T_{OAVG} - \Delta T_{TO/BO}/2$$

When the calculation completes the new value of all temperatures, the calculation loops back to starting point. It reiterates by time step of (Δt) until it reaches the end of the load cycle. The steady-state temperatures rise can be calculated from the following equations

$$\Delta T_{TO} = \left[\frac{\Delta T_{TOR} + \Delta T_{BOR}}{2}\right]\cdot (P_T)^y + \left[\frac{\Delta T_{TOR} - \Delta T_{BOR}}{2}\right]\cdot (P_T)^z \qquad (3.25)$$

$$\Delta T_{BO} = \left[\frac{\Delta T_{TOR} + \Delta T_{BOR}}{2}\right] \cdot (P_T)^y - \left[\frac{\Delta T_{TOR} - \Delta T_{BOR}}{2}\right] \cdot (P_T)^z \qquad (3.26)$$

F or OA, FA, and DFOA Cooling, $\Delta T_{TDOR/BOR} = \Delta T_{TDOR} - \Delta T_{BOR}$

For NDFOA Cooling, $\Delta T_{TDOR/BOR} = \Delta T_{WR} - \Delta T_{BOR}$

For all cooling type $\Delta T_{TDO/BO} = \Delta T_{TDOR/BOR} \cdot K^{2x}$ $\qquad (3.27)$

For OA, FA, and NDFOA Cooling,

$$\Delta T_W = \left[\Delta T_{WR} - \Delta T_{BOR} - \frac{\Delta T_{TDOR/BOR}}{2}\right] \cdot K^{1.6} + \Delta T_{BO} + \frac{\Delta T_{TDO/BO}}{2} \qquad (3.28)$$

$$\Delta T_{HS} = \left[\Delta T_{HSR} - \Delta T_{BOR} - \Delta T_{TDOR/BOR}\right] \cdot K^{1.6} + \Delta T_{BO} + \Delta T_{TDO/BO} \qquad (3.29)$$

For DFOA Cooling,

$$\Delta T_W = \left[\Delta T_{WR} - \Delta T_{BOR} - \frac{\Delta T_{TDOR/BOR}}{2}\right] \cdot K^{2.0} + \Delta T_{BO} + \frac{\Delta T_{TDO/BO}}{2} \qquad (3.30)$$

$$\Delta T_{HS} = \left[\Delta T_{HSR} - \Delta T_{BOR} - \Delta T_{TDOR/BOR}\right] \cdot K^{2.0} + \Delta T_{BO} + \Delta T_{TDO/BO} \qquad (3.31)$$

This model requires more information on the transformer than the classical model. However, it provides more informative results. For this research, this model has been used. It yields more accurate winding losses and hottest-spot calculations.

3.3 IEC 354 Thermal Model

IEC 354 thermal model[2] for transformer hottest-spot calculations is very similar to the IEEE classical model (Clause 7). IEC 354 uses 20°C average ambient temperature and hottest-spot temperature of 98°C for 65°C average winding rise transformer (compared to 30°C average ambient temperature and 110°C hot-spot temperature for ANSI/IEEE). IEC

354 uses different temperature equations (by size and cooling type) to calculate hottest-spot temperature. A direct comparison of the IEEE/ANSI guide and the IEC 354 can be found in reference [11].

3.4 Loss-of-Life Calculation, IEEE Method

In the IEEE loading guide (C57.91-1995), aging equations have been changed to accommodate the recent results. There is no longer the absolute life value. Instead, “the relative aging rate” and “per-unit life” have been introduced. The per-unit life (L) for 65°C average winding temperature rise transformer is defined by (3.32). For, T_{HS} = 110°C , the per-unit life = 1.00.

$$L = 9.80 \times 10^{-18} e^{\left[\frac{15,000}{T_{HS}+273}\right]} \tag{3.32}$$

The equation for the Relative Aging Factor (F_{AA}) can be derived from (3.32):

$$F_{AA} = e^{\left[39.164 - \frac{15,000}{T_{HS}+273}\right]} \tag{3.33}$$

The value of F_{AA} is greater than 1, when the hottest-spot temperature is greater than 110°C, suggesting loss-of-life (from normal aging) and less than 1 when hottest-spot temperature is less than 110°C, meaning life extension. Equation (3.34) may be used to calculate the equivalent aging of the transformer with respect to the reference temperature (110°C) which will be consumed in a given time period (T):

$$F_{EQA} = \frac{1}{T}\int_0^T F_{AA}\, dt \tag{3.34}$$

Equation (3.34) is a dimensionless quantity. The actual loss-of-life in hrs. can be calculated by multiplying F_{EQA} and T(hrs). The % loss of life can then be calculated as:

$$\%Loss\ of\ Life = \frac{F_{EQA} \text{ x } T}{Normal\ Insulation\ Life} \times 100 \tag{3.35}$$

As discussed earlier, the normal insulation life of an oil-filled transformer is not uniquely defined. IEEE provides some acceptable guidelines for the normal insulation life values and the corresponding criteria. This is summarized in Table 3.3.

Table 3.3: Normal insulation life per IEEE C57.91-1995

Basis	Normal Insulation Life	
	Hours	Years
50% Retained Tensile Strength(Former C57.92)	65,000	7.42
20% Retained Tensile Strength of Insulation and/or 200 Retained Degree of Polymerization (DP)	150,000	17.12
Distribution Transformer's Functional Life	180,000	20.55

Note: Data in Table 3.4 is applicable to well-dried, oxygen-free, 65°C avg. winding rise, hottest-spot temperature of 110°C transformer

3.5 Comparison of the IEEE Thermal Models: Numerical Examples

As mentioned earlier in this Chapter, the IEEE classical model (Clause 7) is simpler and requires less information. The model, as discussed in IEEE Standard Annex G, on the other hand is complex and requires more input data to calculate the transient responses of transformer. The comparison of the input data requirement is tabulated in Table 3.4.

Table 3.4: Required data for IEEE thermal models

IEEE Classical Model (Clause 7)	IEEE Detailed (Annex G) Model
Top-oil temperature rise at rated load	Top-oil temperature rise at rated load
Hot-spot temp. rise over top-oil @ rated load	Hottest-spot temperature rise at rated load
Loss ratio at rated load	Average winding temp. rise at rated load
Winding time constant	Bottom oil temperature rise at rated load
Oil time constant or	Losses data from test report
Weight of core & coil	kVA base of test data
Weight of tank & fittings	Winding temperature rise at tested rating
Gallons of fluid	Winding losses
Type of cooling system	Winding eddy current losses
	Stray losses
	Core losses
	Weight of core & coil
	Weight of tank & fittings
	Gallons of fluid
	Type of cooling system
	Type of cooling fluid
	Type of winding material
	Winding time constant
	Location of hottest spot
	pu eddy current losses at hot-spot location

Several simulations were performed to compare the two methods. Although the two models use different approaches and heat transfer equations, the steady-state solutions for the top-oil and hottest-spot temperatures are surprisingly close. Table 3.5 contains partial transformer data (design values) used in the comparison for steady-state temperature rise. The transformer loading is increased by an increment of 0.2pu to a continuous loading of

1.4pu. The comparison is tabulated in Table 3.6. The temperature difference is within 2-3°C for most cases except for DFOA and NDFOA cooling systems and at very high loading of 1.2 and 1.4pu. The Annex G model yields much higher top oil and hottest-spot temperature at loading beyond 1.2pu. This is due to the higher duct oil rise exponent, x of DFOA cooling system (see Table 3.2).

Table 3.5: Transformer data for temp. rise comparison at steady-state, IEEE methods

Clause 7 input data (Design Values)	T_{HSR} = 110°C Loss ratio (R) = 4.1 T_{TOR} = 55°C for OA T_{TOR} = 45°C for FA, NDFOA, and DFOA
Annex G input data (Design Values)	T_{HSR} = 110°C T_{TOR} = 55°C for OA T_{TOR} = 45°C for FA,NDFOA, and DFOA T_{BOR} = 25°C P_{WR} = 138,257 watts P_{SR} = 42,085 watts P_C = 43,986 watts Mass of core & coil = 61,050 lb. Mass of tank & fittings = 26,050 lb. Oil volume = 4,110 gallons

Note: The suffix letter “R” on all the suffixes is referred to the rated (or full-load) condition (design limit)

IEEE Annex G thermal model, however, has improved transient response, since it takes heat transfer in duct oil into considerations. A computer program is written. The program is capable of calculating the temperature profiles from the IEEE thermal models. The program also computes the transformer loss-of-life based on insulation deterioration.

Table 3.6: Comparison of top-oil and hottest-spot temperature of IEEE thermal models (constant load, 30°C ambient temperature)

Cooling type	Load (pu)	Top oil temperature			Hottest-spot temperature		
		Clause 7	Annex G	Diff.	Clause 7	Annex G	Diff.
OA	0	44.9	47.5	+2.6	44.9	47.5	+2.6
	0.2	46.9	49.3	+2.4	48.8	51.3	+2.5
	0.4	52.4	54.3	+1.9	58.1	60.5	+2.4
	0.6	60.9	62.2	+1.3	71.9	73.7	+1.8
	0.8	71.8	72.4	+0.6	89.3	90.3	+1.0
	1.0	85.0	85.0	0	110.0	110.0	0
	1.2	100.1	99.9	-0.2	133.5	134.2	+0.7
	1.4	116.9	117.2	+0.3	159.7	161.5	+1.8
FA	0	40.4	42.5	+2.1	40.4	42.5	+2.1
	0.2	41.9	43.9	+2.0	44.6	46.8	+2.2
	0.4	46.4	48.0	+1.6	54.4	56.5	+1.1
	0.6	53.5	54.6	+1.1	68.9	70.7	+1.8
	0.8	63.1	63.6	+0.5	87.6	88.6	+1.0
	1.0	75.0	75.0	0	110.0	110.0	0
	1.2	89.1	89.1	0	136.0	136.0	0
	1.4	105.3	106.1	+0.8	165.3	165.8	+0.5
NDFOA	0	38.8	40	+1.2	38.8	40.0	+1.2
	0.2	40.3	41.4	+1.1	42.9	46.9	+4.0
	0.4	44.6	45.6	+1.0	52.7	57.9	+5.2
	0.6	51.8	52.5	+0.7	67.3	72.9	+5.6
	0.8	62.0	62.3	+0.3	86.5	90.3	+3.8
	1.0	75.0	75.0	0	110.0	110.0	0
	1.2	90.9	91.0	+0.1	137.8	132.1	-5.7
	1.4	109.7	110.6	+0.9	169.7	156.8	-12.9
DFOA	0	38.8	38.8	0	38.8	38.8	0
	0.2	40.3	40.1	-0.2	41.7	41.3	-0.4
	0.4	44.6	44.2	-0.4	50.2	48.8	-1.4
	0.6	51.8	51.0	-0.2	64.4	61.9	-2.5
	0.8	62.0	61.1	-0.9	84.4	81.7	-2.7
	1.0	75.0	75.0	0	110.0	110.0	0
	1.2	90.9	93.9	+3.0	141.3	154.1	+12.8
	1.4	109.7	120.1	+10.4	178.3	219.6	+41.3

The program features easy data input, graphical user interface, save, print and copy to clipboard. The program calculates hottest-spot temperature, top-oil temperature and other temperature profiles using daily load and ambient temperature profiles based on IEEE thermal model Annex G, Clause 7, and IEC 354. It also plots temperature profiles and text results. The program calculates the loss-of-transformer functional life based on thermal model (IEEE only). Program utilizes monthly load, temperature profiles, and load growth rate from table. Estimated remaining tensile strength and degree of polymerization are also reported.

The graphical outputs of a test case for step load changes are plotted in Figure 3.4 and Figure 3.5. The step load increases from 0 to 1.0 pu and remains constant for 4 hours.

The forced-air (FA) cooled transformer data from Table 3.45 is utilized. The ambient temperature is held constant at 30°C.

When compared, it is seen that, the hottest-spot temperature in Annex G model rises more sharply when the load steps up. With the inclusion of heat transfer in duct oil, for any typical load profile, the IEEE Annex G thermal model yields higher hottest-spot temperature than corresponding IEEE Clause 7 thermal model , so does the loss of insulation life.

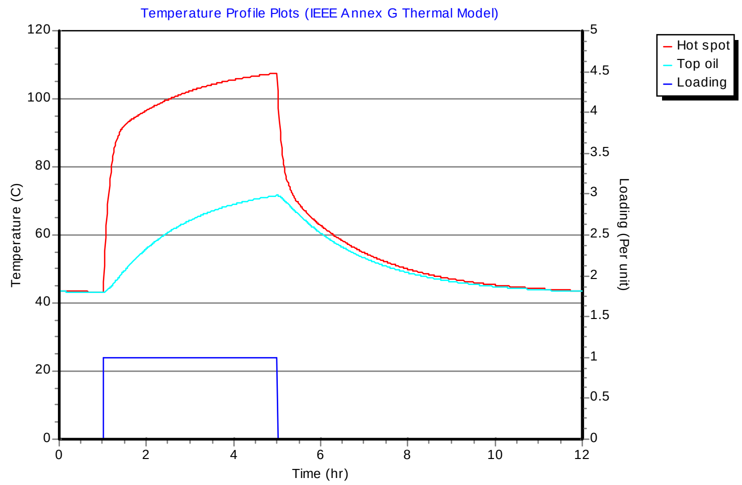

Figure 3.4: Temperature profiles of IEEE Annex G thermal model subjected to step load

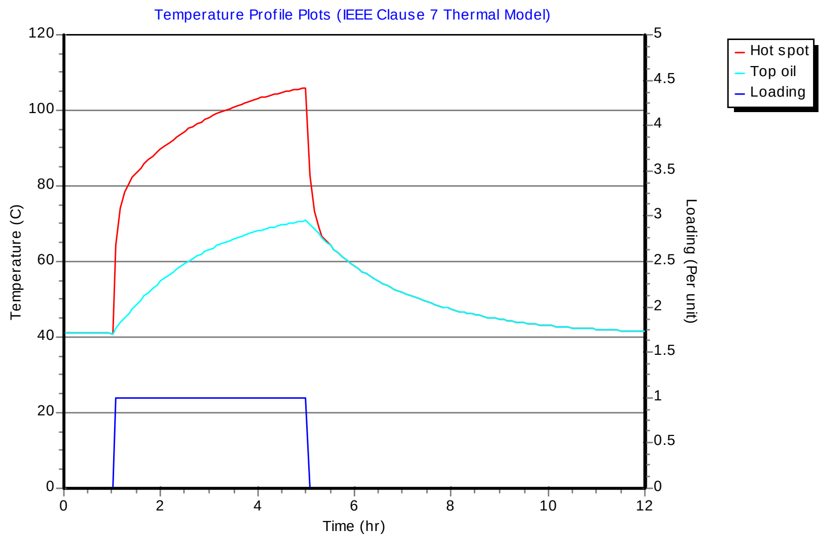

Figure 3.5: Temperature profiles of IEEE Clause 7 thermal model subjected to step load

4. Probabilistic Assessment of Transformers Loss-of-Life

4.1 Introduction

Utilities generally select the size and overload the transformers, when necessary, following the IEEE loading guide or a guide of their own. This generally provides the deterministic calculation of transformer loss-of-life at given elevated hottest-spot temperatures. In this method, the exact mean ambient temperature and the transformer hottest-spot temperature values are assumed known. However, in a real-life practical application, because of a number of variables, the exact amount of overloading is difficult to determine. Use of some statistical approaches to evaluate these parameters which may be obtained from utility's monitoring system and weather station data, may provide more flexibility and better result. In the probabilistic analysis, discussed in this chapter, ambient temperature (T_A) and the transformer loading (K) are taken as uncertainties. Monte Carlo technique is utilized to calculate the probabilistic distribution of the winding hottest-spot temperature and calculate the expected value of transformer aging rate and the corresponding percent loss-of-life. This also can help the utilities to make decisions regarding the transformer overloading and the sizing of transformer under uncertainties.

4.2 Modeling

4.2.1 Transformer Loading (*K*)

The daily loading data of a transformer can be obtained from some real-time monitoring systems (via SCADA). However, the future forcasting depends on a number of variables. In a simplified model, the transformer loading is assumed to be charaterized by a Gaussian distribution (normal distribution) with its mean value of (μ_k) and between 5-20 percent [36] of the mean as its standard deviation (σ_k). Mathematically,

$$K = Gauss\,(\mu_k, \sigma_k^2) \tag{4.1}$$

4.2.2 Ambient Temperature (T_A)

Similarly, the ambient temperature at any given day and time can also be described by a Gaussian distribution from the available historical or forecasted data. The typical value of ambient temperature standard deviation is between 10-30 percent [36] of its mean. Mathematically,

$$T_A = Gauss\,(\mu_a, \sigma_a^2) \tag{4.2}$$

4.2.3 Correlation between loading and ambient temperature (ρ)

In a real power system, the transformer loading is related with the ambient temperature. The correlation coefficient (ρ) ranges between (–1) to (+1). The correlation is generally positive in the summer months and turns negative in the winter.

4.3 Monte Carlo simulation

Monte Carlo simulation technique is utilized to randomly create a set of data points corresponding to a transformer loading (*K*) at an ambient temperature of (T_A) with correlation coefficient of (ρ). A hottest-spot temperature profile is then produced from the thermal model discussed earlier. Then relative aging rates (F_{AA}) are calculated from the hottest-spot temperatures using equation (3.33). The Expected Value (mean) of the relative aging rate is calculated as defined by equation (4.3)and substituted in equation (4.4) for the calculation of percent loss-of-life. Mathematically,

$$E(F_{AA}) = \int_{-\infty}^{\infty} F_{AA} P_r (F_{AA}) dF_{AA} \tag{4.3}$$

The percent Loss of Life becomes

$$\%Loss\ of\ Life = \frac{\int_0^T E(F_{AA})\, dt}{Normal\ Insulation\ Life} \times 100 \tag{4.4}$$

The Monte Carlo simulations generate bivariate normal distributions with correlation coefficient (between the ambient temperature and transformer loading) in a study region. In order to generate the bivariate normal distributions with a correlation coefficient, a pair of independent standard normal distributions, $U,V:N(0,1)$, is generated from the computer program MATLAB or Box-Muller method[37]. By substituting *U* and *V* in equation (4.3) and (4.4), yields bivariate normal distributions *X* and *Y* that represent ambient temperature (T_A) and transformer loading (*K*), respectively as:

$$X = \mu_X + \sigma_X (U) \tag{4.5}$$

$$Y = \mu_Y + \rho_{XY} \sigma_Y (U) + \sigma_Y \sqrt{1 - \rho_{XY}^2} (V) \tag{4.6}$$

Where, μ_X, μ_Y and σ_X, σ_Y are the means and standard deviations of variables *X* and *Y*, and ρ_{XY} is the correlation coefficient between (–1) to (+1). The computation technique using the Monte Carlo Simulation is displayed in a flowchart (Figure 4.1).

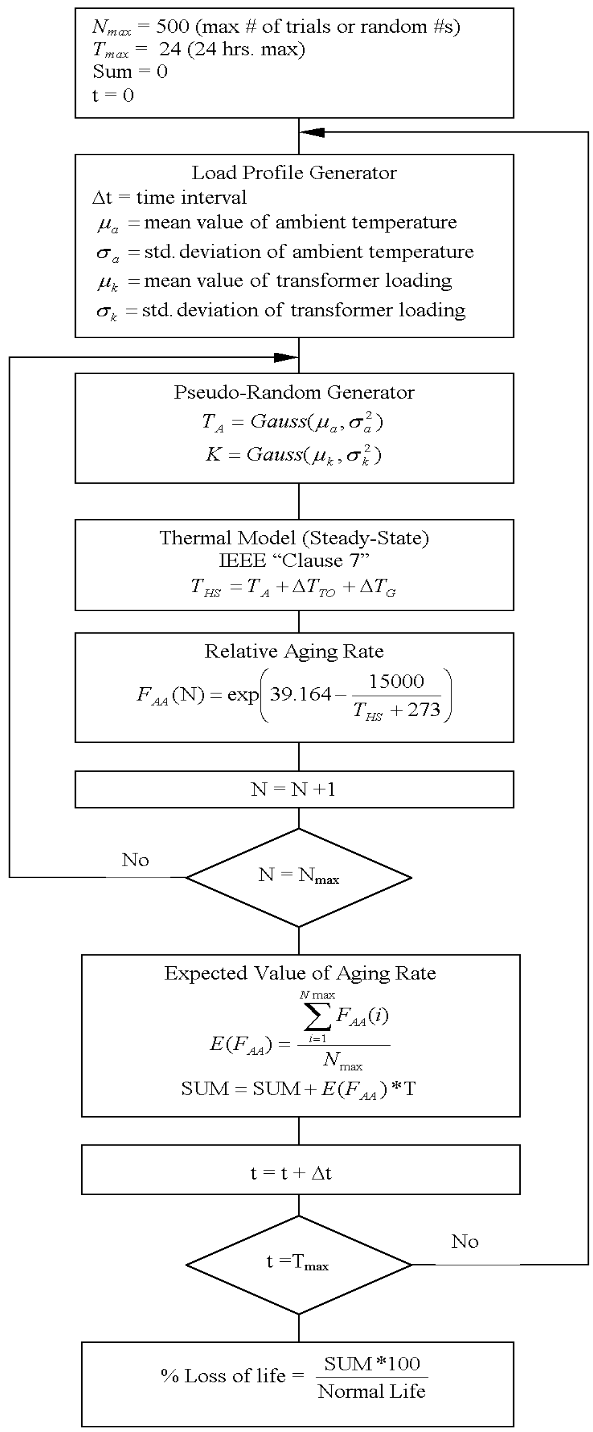

Figure 4.1: Monte Carlo simulation

4.4 Numerical example

To better understand the modeling and the Monte Carlo Simulation technique discussed earlier, an actual simulation is performed. In this example, a constant loading (*K*) of 1.0 per-unit (μ_k) with 5% standard deviation (σ_k), and the ambient temperature's mean of 30°C (μ_a) and a 10% standard deviation (σ_a) is used. The correlation coefficient (ρ) is assumed randomly to be 0.2. The Monte Carlo simulation generates 500 random numbers for each random ambient temperature and transformer loading. The random relationship between the ambient temperature and the transformer loading is plotted in Figure 4.2. Figure 4.3 depicts the probability of the T_A and K relationship generated randomly by the program.

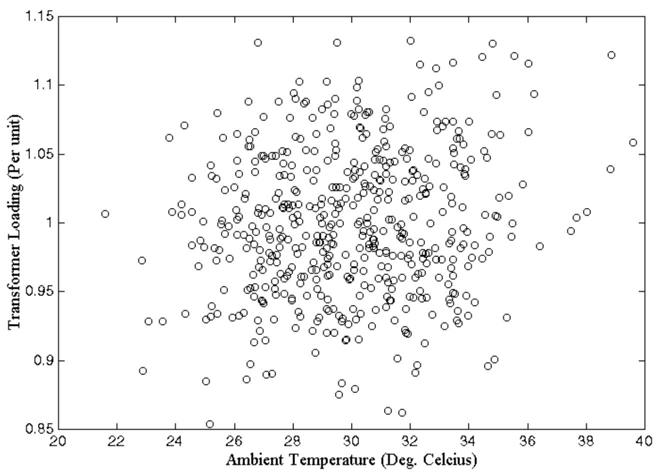

Figure 4.2: Relationship between ambient temperature and transformer loading with correlation coefficient of 0.2.

The transformer in this example is assumed to be a naturally cooled unit (OA). Figure 4.4 shows the Monte Carlo simulation results of the distribution of transformer hottest-spot temperatures. It shows that the mean hottest-spot temperature is 109.97°C (ideal value of 110°C), and the calculated standard deviation is 7.1°C.

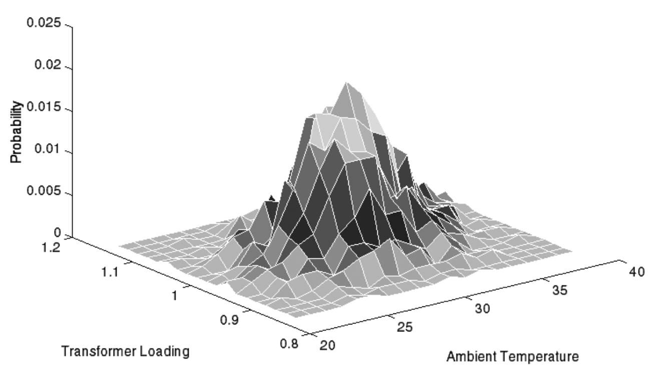

Figure 4.3: 3-D plot of ambient temperature and transformer loading

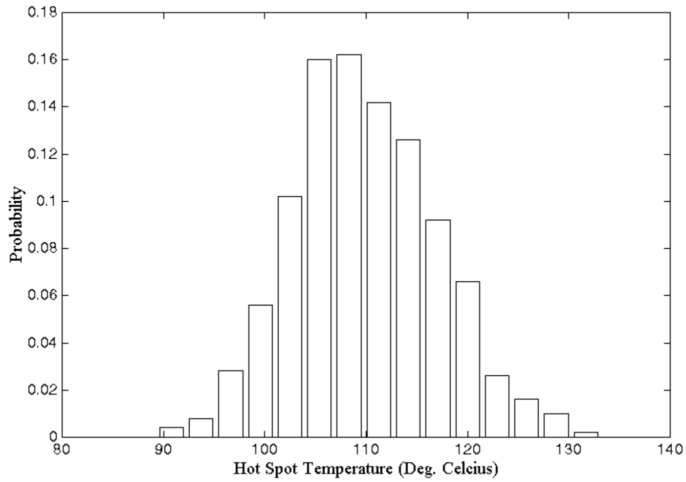

Figure 4.4: Distribution of hottest-spot temperature

The probability distribution of the relative aging rate (F_{AA}) as calculated from equation (4.3) for those randomly selected points is shown in Figure 4.5. The calculated value of the relative aging rate in this example is 1.28. This is an important number. In a deterministic situation as applied in the thermal model, transformer loading of 1.0 pu at an ambient temperature of 30°C produces a relative aging rate of 1.0 and a corresponding transformer life of 1.0 pu. However, with the probabilistic analysis discussed in this section, when the uncertainties are taken into account for a naturally cooled transformer at 30°C ambient temperature, the relative aging rate at a mean 1.0 per-unit loading is 28% higher than the corresponding deterministic (Classical) value. This is because, the relative aging at a higher ambient temperature (T_A) and higher pu loading (K) yields more loss-of-life compared to the corresponding savings at lower values of K and T_A.

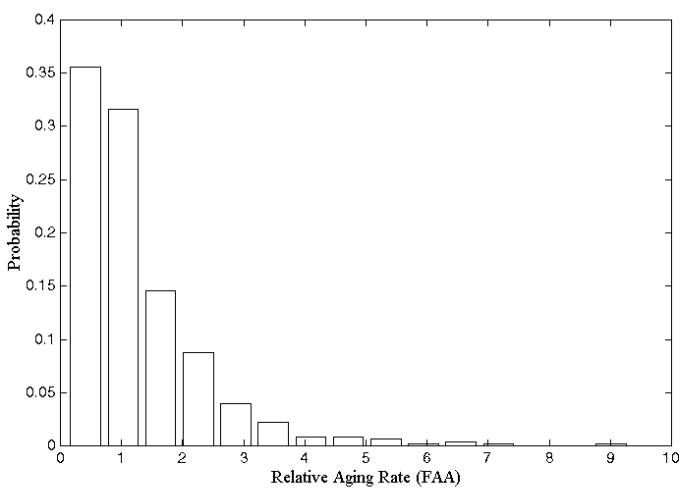

Figure 4.5: Distribution of relative aging rate (F_{AA})

The same technique have been extended to other types of cooling and variable correlation coefficient (ρ). The results are shown in Figure 4.6. The relative aging rate increases rapidly as correlation factor increases from (–1) to (+1) and the value is always greater than 1.0.

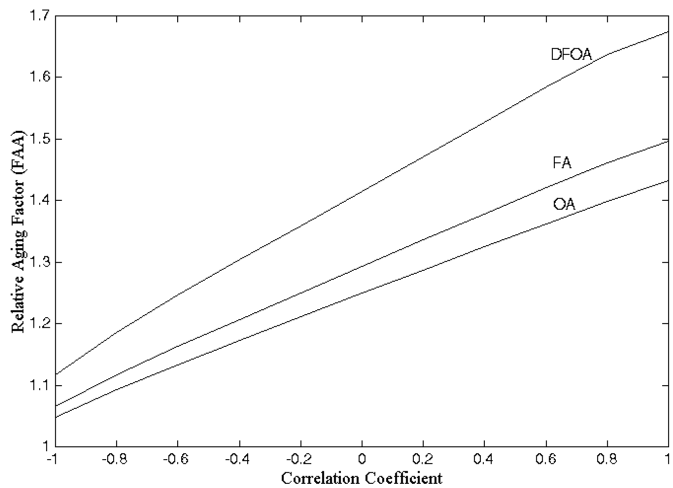

Figure 4.6: Relative aging rate with different correlation coefficient on various types of transformer cooling

In summary, the probabilistic approach always produces a higher value of aging rate and the corresponding loss-of-life. This is because of much higher insulation deterioration rate at elevated temperature as compared to low temperature. It is also clear, that the relative aging rate varies widely with the correlation between ambient temperature and transformer loading and the type of transformer cooling.

5. Transformer Economic Evaluation

In order to accommodate increased demand, overloading of transformers and accepting the reduced life expectancy as a result of higher hottest-spot temperature rise must be evaluated carefully against the delay in transformer replacement or addition of a second transformer. The utility engineers usually determine the size of transformers from the current loading, expected future load growth, and other appropriate engineering judgments. Utilities evaluate the economic impact of losses in a transformer prior to purchasing along with the initial price. The conventional method called “Total Owning Cost”. A detailed analysis called “Revenue Requirement Method” is more appropriate for the Investor-Owned Utilities (IOU’s).

5.1 Loss Evaluation: Conventional Method

Procurement of transformers by the Loss Evaluation is the most widely used and it is based on the lowest total owning cost. The method evaluates the cost of transformer’s losses and the purchasing price. The service life of transformer is assumed to be constant regardless of size. Generally it is chosen to be 30 years.

5.2 Revenue Requirement and Fixed Charge Rate

In the Revenue Requirement method, the annual operating cost is written as:

$$E_A = R_A - (P_A + D_B + T) \qquad (5.1)$$

where: E_A is the annual equity return (net income),
R_A is the annual revenue,
P_A is the annual production expense,
D_B is the depreciation, and
T is the income tax.

Equation (5.1) can be rearranged:

$$R_A = P_A + (E_A + D_B + T) \qquad (5.2)$$

Except for the annual production expense (P_A), the remaining items within the parenthesis on the right hand side of this equation can be expressed as a function of the capital investment. Hence, the equation may be re-written as:

$$R_A = P_A + FCR * (\text{Capital Investment}) \qquad (5.3)$$

$$R_A = P_A + (i + i_d + i_t) * (\text{Capital Investment}) \tag{5.4}$$

where: FCR is the fixed charge rate in per unit,
i is the cost of capital (in decimal) or discount rate,
i_d is the depreciation rate, and
i_t is the income tax rate.

A very simple, yet realistic, example of fixed charge rate (FCR) is as follow,

- Cost of capital 10.0%
- Depreciation rate 0.6%
- Income tax rate 8.6%
- Fixed charge rate 19.2% or (FCR = 0.192)

Rearranging, the first cost revenue requirement (R) is given by:

$$R = \frac{P_A}{FCR} + \text{Capital Investment} \tag{5.5}$$

This equation (5.5) is used in the Loss Evaluation Method and the objective function is defined as:

$$min\ R = \frac{P_A}{FCR} + \text{Capital Investment} \tag{5.6}$$

5.2.1 Transformer Loss Evaluation

The Capital Investment is the purchasing price. P_A is the annualized cost of core and winding losses including cost of demand charge for these losses. When annualized cost of losses is divided by the fixed charge rate (FCR), it yields the total (net) revenue requirement for the cost of losses.

For each of no-load (core), load (winding), and auxiliary losses, there will be a demand (kW) component based on the capital cost of generation and transmission/ distribution equipment. In addition, there will be a cost due to the energy (kWh) component. As a result, the total cost of losses is:

$$\text{Cost of Losses (\$/kW)} = \text{Demand Cost} + \text{Energy Cost}$$

$$= \text{System Investment (\$/kW)} + \frac{8760 \times \text{Annualized Energy Cost}}{\text{Fixed Charge Rate}} \tag{5.7}$$

$$= \frac{\text{Annualized Demand Charge (\$/kW - yr)} + 8760 \times \text{Annualized Energy Cost}}{\text{Fixed Charge Rate}}$$

Equation (5.7) is conveniently applied by utilities with generation and without generation. The formulas given below yield the total evaluated cost for each category of losses separately in $/kW. These costs of losses are then multiplied by transformer's corresponding kW losses and added to the purchase price, so that losses can be properly taken into account.

$$NLCR\ (\$/\text{kW}) = SI + \frac{8760(AEC)}{FCR} \qquad (5.8)$$

$$LLCR\ (\$/\text{kW}) = SI\ (PRF)^2 (EPR)^2 + \frac{8760(AEC)(TLF)(EPR)^2}{FCR} \qquad (5.9)$$

$$ALCR\ (\$/\text{kW}) = SI\ (PRF)^2 + \frac{8760(AEC)(PA)}{FCR} \qquad (5.10)$$

where: *NLCR* = No-load (core) losses cost rate ($/kW)
LLCR = Load (winding) losses cost rate ($/kW)
ALCR = Auxiliary losses cost rate ($/kW)
SI = System investment cost for additional generation, transmission and Distribution needs ($/kW)
8,760 = Number of hours in a Year
AEC = Annualized energy cost ($/kWh)
FCR = Fixed charger rate (in decimal)
PRF = Peak responsibility factor
EPR = Equivalent peak ratio
TLF = Transformer loss factor
PA = Probability that the auxiliary cooling will be "ON"

In Total Owning Cost method (TOC), equations (5.8) and (5.9) are usually referred to as "*A*" and "*B*" factors, respectively.

$$\text{Total Owning Cost } (TOC) = \text{Purchase Price} + NLCR * NLL + LLCR * LL + ALCR * ALL \qquad (5.11)$$

where: *NLL* = No-load (core) loss in kW.
LL = Load (winding) loss in kW.
ALL = Auxiliary load loss in kW.

Most commonly, if auxiliary loss is neglected, equation (5.11) is rewritten as

$$\text{TOC} = \text{Bid Price} + A * NLL + B * LL \qquad (5.12)$$

5.2.2 Discussion of Factors

- System Investment (*SI*) represents the investment in generation, transmission, and distribution facilities necessary to supply the additional demand resulting from the transformer losses at the system peak. There are basically two methods for evaluating the SI value: (i) the actual construction cost of a recent generating station and the required transmission/distribution facilities, and (ii) if the utility is purchasing power rather than self-generating, the *SI* value can be obtained by dividing the demand charge ($/kW-yr) by the fixed charge rate (*FCR*).
- Annualized Energy Cost (*AEC*): Since the energy price changes with inflation, it is recommended that AEC be used instead of present energy cost. The AEC is calculated by listing the projected cost of energy and discount these annual inflated cost by appropriate present worth factor. Add each of the present worth value of the energy cost and multiply by the capital recovery factor (*CRF*). Mathematically, AEC = sum of present worth value $\times\, CRF$

$$= \text{present energy cost}\left(X\left[\frac{1\text{-}X^{N}}{1\text{-}X}\right]\right)\left(i\left[\frac{(1+i)^{N}}{(1+i)^{N}-1}\right]\right) \qquad (5.13)$$

where: N = Transformer book life

$X = \dfrac{1+e}{1+i}$

e = Energy escalation rate (in decimal)

i = Cost of capital or discount rate (in decimal)

CRF = Capital recovery factor

- Fixed Charge Rate (*FCR*) represents the annual cost necessary to support a capital investment. The rate includes the cost of money, depreciation, income tax, insurance and maintenance expenses independent of energy (kWh) sold.
- Peak Responsibility Factor (*PRF*) is intended to compensate for the fact that the transformer peak load losses does not necessarily occur at the same time as the system peak. This means that only a fraction of the peak transformer losses will contribute to the system peak demand. The value of *PRF* is determined by (5.14):

$$PRF = \frac{\textit{Transformer load at the time of system peak}}{\textit{Transformer peak load}} \qquad (5.14)$$

The typical values of peak responsibility factor can range from 1.0 down to 0.35. Since *PRF* is a ratio of load (kVA), the losses are the function of $(PRF)^2$. The followings are typical values[42] of *PRF*.

Transformer Type	*PRF*
Generator step-up	1.0
Transmission substation	0.9
Distribution substation	0.8
Distribution	0.35

- Equivalent Peak Ratio (*EPR*): The peak ratio (*PR*) is to relate the losses to the rated transformer load. The peak ratio (peak pu) loading is defined by:

$$PR = \frac{Peak\ annual\ transformer\ load}{Full\ rated\ transformer\ load} \tag{5.15}$$

If the load grows by a given percent every year, the equivalent peak ratio (*EPR*) should be used instead. *EPR* can be calculated from:

$$\text{Equivalent Peak Ratio}\ (EPR) = PR\sqrt{\frac{(1+g)^{2t}-1}{\ln(1+g)^{2t}}} \tag{5.16}$$

where: PR = the present peak ratio
g = the load growth rate (in decimal)
t = time in years

- Transformer Loss Factor (*TLF*) is the ratio of the average load loss to the peak load losses over a given period of time (typically one year period).

$$TLF = \frac{Average\ load\ loss}{Peak\ load\ loss} \tag{5.17}$$

If the annual load data (load cycle) is available, the load losses can be calculated from this information. However, the utility engineers try to relate the transformer loss factor with a more readily available information called Load Factor (*LF*). *LF* is defined as the ratio of the average load over the peak load. *TLF* cannot be determined uniquely from the load factor. The utility engineers have been using an empirical formula defined by equation (5.18) for *TLF* in terms of *LF* as

$$\text{Transformer Loss Factor}\ (TLF) = a(LF)^2 + b(LF) \tag{5.18}$$

where: LF = Load factor

"a" and "b" are constants, such that $a+b = 1.0$

The constant "a" can vary from 0.8 - 0.89, whereas, "b" varies between 0.2 - 0.11. The recommended typical values[42] of "a" and "b" are 0.84 and 0.16, respectively.

- <u>Probability that the auxiliary cooling will be "ON"</u> (*PA*) for the transformer life-time depends on many factors such as transformer size, load profile, load growth, and ambient temperature. The choice is a matter of engineering judgment.

5.2.3 An Example

Assume the following data to perform the loss evaluation, and to purchase a 2,000kVA, (OA) liquid filled, 65°C average winding temperature rise transformer.

Book life	30 years
System investment (*SI*)	$1,400/kW
Discount rate (*i*)	10%
Energy escalation rate (*e*)	2%
Fixed charge rate (*FCR*)	0.192
Present Energy cost (*EC*)	$0.035/kWh (3.5 cents/kWh)
Peak responsibility factor (*PRF*)	0.6
Peak ratio (*PR*)	0.7
Load growth rate (*g*)	2%
Load factor (*LF*)	0.6

Table 5.1: Loss Evaluation Calculation Example

Manufacturer	Losses (kW)		Bid Price	Cost of Losses *A*NLL+B*LL*	Total Owning Cost Equ. (4.13)
	No-load (*NLL*)	Load (*LL*)			
X	5.8	23.2	$28,000	$49,449	$77,449
Y	4.0	18	$31,000	$36,622	$67,622
Z	4.0	14	$34,000	$31,584	$65,584

Based on the above data, the following values are calculated.

AEC = $0.046 (or 4.6 cents/kWh)
EPR = 0.97
TLF = 0.4
$NLCR$ = 3,487 $/kW, and

Table 5.1 is self-explanatory. It compares the actual bid price and the corresponding losses with the total owning cost values for three different designs (manufacturer X, Y, and Z).

Design X is the standard design. Design Y and Z is the low loss design (better core material and larger conductor size).

After the loss evaluation is taken into account, the transformer manufactured by Z is the most cost effective over the normal operating life, even though the bid price (initial purchase price) is the highest.

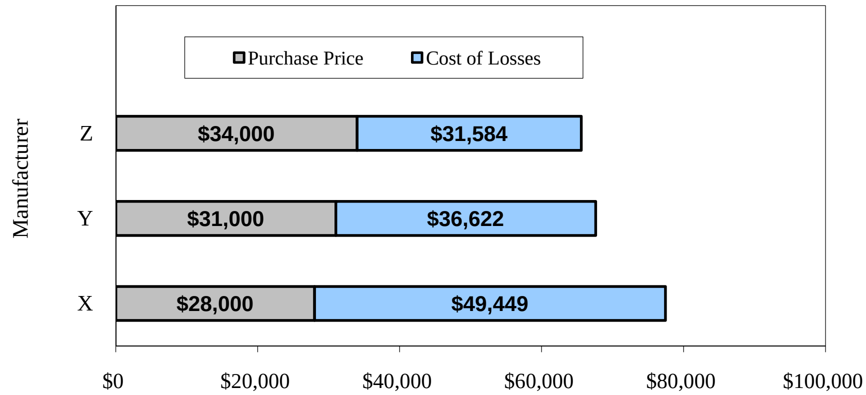

Figure 5.1: Total owning cost of different manufactured transformers

This example shows that the cost of losses over the transformer life is worth evaluating and is comparable to the initial purchased price.

5.3 Engineering Economic Evaluation for Investor-Owned Utilities

Utilities are monopolistic in the sense, that they are granted a franchise to provide quality and reliable power supply within an area. Utilities, in turn, charge a unit price allowing only for a fair profit beyond the unit cost and have the capability to attract enough capital to finance new projects. Amongst other responsibilities of PUC, its major duty includes the setting of rates, so that excessive profits are eliminated, and the establishment and maintenance of standards of service.

5.3.1 Characteristics of Investor-Owned Utilities (IOU's)

The characteristics of investor-owned utilities as appropriate for this discussion are listed below:

- IOU's are capital intense whose ratio of fixed costs to variable costs is very high.
- The rates charged to customers for a utility's services are based on the total costs, including a fair return for the stockholders after income tax.
- A basic concept of "rates" setting is that they must be able to earn enough profit to pay dividends and to attract the capital necessary for rendering the service.

- The earnings of a utility are limited by the rate base. The upper limit of profit is usually set not to exceed about 12% - 16% on equity capital.

- Because of the stable nature of their business and earnings, utilities commonly finance their capital expenditures with a higher percentage (50-70% range) of borrowed capital. Utilities must rely on a larger proportion of new capital for expansion than do other companies.

- Utilities are much less limited in term of the availability of capital than are non-utility companies, due to their greater stability of revenues and earnings.

5.3.2 Development of the Revenue Requirement Method for Transformer Economic Evaluation

The economic strategy widely used by regulated utilities is the "Minimum Revenue Requirement Method." [44] It calculates the revenues that a given project must collect just to meet all the costs associated with it, including a fair return to investors. The relationship between revenue requirements and various components of its costs is shown in Figure 5.2. At the end, the revenue requirements are minimized.

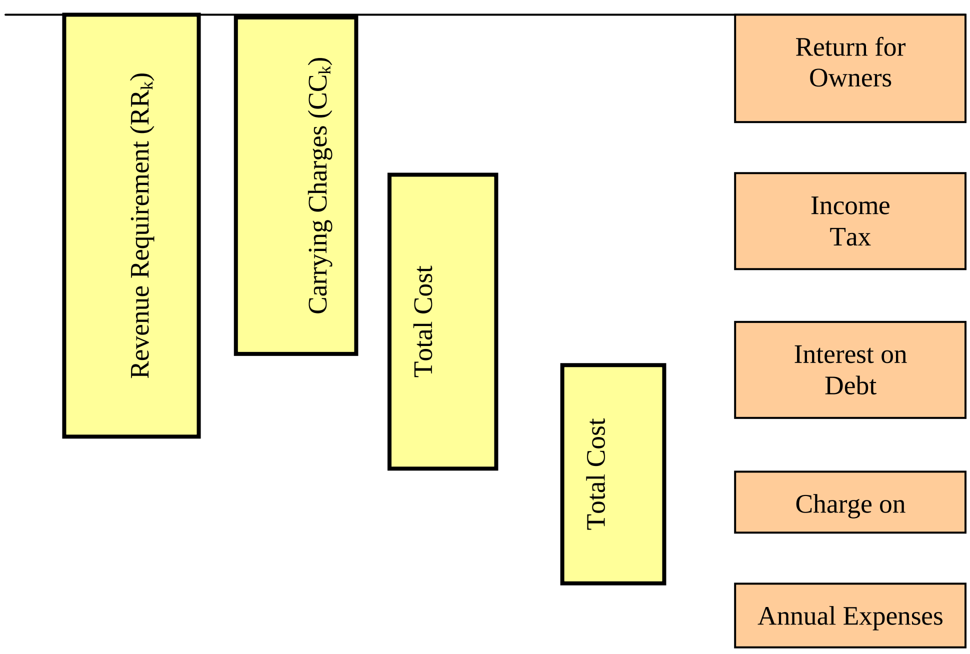

Figure 5.2: Relationship of revenue requirements and costs for an IOU

The minimum revenue requirement consists of carrying charges resulting from capital investments that must be recovered, plus all associated expenses. It can be shown that, the annual carrying charges in year k (CC_k) is given by

$$CC_k = [(1-\lambda)i_e + \lambda i_b] \cdot UI_k + D_{Bk} + T_k \tag{5.19}$$

where: CC_k is annual carrying charge in year k ($)

λ is debt ratio (fraction of borrowed money in total capital)

i_e is equity return rate in decimal

i_b is cost of borrowed money in decimal

UI_k is unrecovered investment (cost of transformer) at year k

$UI_k = I$ (initial investment), $k = 1$

$UI_k = UI_{k-1} - D_{Bk-1}$, $2 \le k \le N$

N is transformer book life

D_{Bk} is book depreciation in year k, $1 \le k \le N$

T_k is income taxes paid in year k

The depreciation calculated in this research from the “straight line method (SL)”:

$$D_{Bk} = \frac{I - MV}{N} \tag{5.20}$$

Where, MV is market value (Salvage Value) of transformer at the end of year N.

Since depreciation claimed for income tax purposes and interest paid on debt are tax deductible, the income tax in any given year (k) is determined by

$$T_k = i_t(CC_k - \lambda i_b \cdot UI_k - D_{Tk}) \tag{5.21}$$

Where, D_{Tk} is the tax depreciation in year k and i_t is the effective income tax rate.

$$T_k = \frac{i_t}{1 - i_t} \cdot [(1-\lambda)i_e \cdot UI_k + D_{Bk} - D_{Tk}] \tag{5.22}$$

The revenue requirement in year k (RR_k) (see Figure 5.2) is then:

$$RR_k = CC_k + COL_k \tag{5.23}$$

Where, COL_k is the cost of transformer losses in year k.

To compare between the alternatives, the "levelized" revenue requirement ($\overline{RR}$) is introduced. It can be found from discounting all annual revenue requirements for all years of study period to the beginning year and multiplying by the capital recovery factor (*CRF*). Mathematically,

$$\overline{RR} = \sum_{k=1}^{N} \left(RR_k \cdot \frac{1}{(1+i)^k} \right) \cdot CRF(i) \qquad (5.24)$$

when

$$CRF(i) = i \left(\frac{(1+i)^N}{(1+i)^N - 1} \right) \qquad (5.25)$$

Where, $\overline{RR}$ is levelized revenue requirement in dollars,
i is the discount rate or real (inflation-free) after-tax cost of capital.

The real (inflation-free) after tax of capital, i can be found from:

$$i = \frac{\lambda(1-i_t)i_b + (1-\lambda)i_e - \lambda i_t \bar{e}}{1+\bar{e}} \qquad (5.26)$$

where: i is the real (inflation-free) after-tax cost of capital, and
$\bar{e}$ is average annual inflation rate.

Alternate way to compare is the "Capitalized Revenue Requirement (*CRR*)":

$$CRR = \frac{\overline{RR}}{i} \qquad (5.27)$$

Capitalized Revenue Requirement is the same measure as the Total Owning Cost (*TOC*) in loss evaluation method discussed earlier in equation (5.12).

5.3.3 Spreadsheet Illustration of the Revenue Requirement Method

The following example is discussed to demonstrate the concept:

In this example, the cost of a transformer throughout its service life is calculated. The transformer is subjected to a constant 1.0 pu load. The transformer and utilities financial data used in this assessment are listed below:

Transformer size = 20 MVA (Highest rating in case of a FA design)
No-load (core) loss = 30 kW
Load (winding) loss = 80 kW @ 20MVA output

Transformer Service life (book life) = 30 years
Transformer and installation cost = $400,000
Market (Salvage) value, *MV* = $40,000 (at the end-of-life)
Demand charge = $140/kW-yr
Energy cost (present) = $0.035/kWh
Demand charge escalation rate = 0%
Energy cost escalation rate = 0%
Peak responsibility factor *PRF* = 0.8
Cost of no-load losses = $13,400 per year (=30*140+30*8760*0.035)
Cost of load losses = $33,500 per year (=80*0.8*140+80*8760*0.035)
Real (inflation-free) cost of borrowed money, i_b = 5% per year
Real (inflation-free) return on equity, i_e = 16% per year
Debt ratio, λ = 0.3
Effective income tax rate, i_t = 50%
Book depreciation method = straight line
Average annual inflation rate, $\bar{e}$ = 0%

$$D_{Bk} = \frac{\$400{,}000 - \$40{,}000}{30} = \$12{,}000 \qquad \text{from equation (5.20)}$$

Generally, $D_{Tk} = D_{Bk} = \$12{,}000$

$$COL_k = \$13{,}400 + \$33{,}500 = \$46{,}900$$

$$i = [0.3(1-0.5)0.05 + (1-0.3)0.16 - (0.3)(0.5)(0)]/(1+0) = 0.12 \quad \text{Eq.(5.26)}$$

$$CRF = 0.12\left[\frac{(1+0.12)^{30}}{(1+0.12)^{30}-1}\right] = 0.12414 \qquad \text{from equation (5.25)}$$

The result of the example is illustrated in Table 5.2. In case the transformer in the example has to be replaced before 30 years, the unrecoverable investment less book depreciation plus market value of that year is the unpaid investment cost. It has to be paid by additional revenue at the end of that year.

Let's assume that the transformer from the previous example is overloaded to the end of its life in 5 years. As a result, it has to be replaced at the end of the 5th year. Unrecoverable investment (UI_k) at the end of 5th year due to early replacement is $340,000 (=$352,000-$12,000). The transformer is sold at the market value (salvage) of $40,000. Hence, the additional revenue required to cover the cost is $300,000 (=$340,000-$40,000). So the 5th year revenue requirement has to be $443,028. Table 5.3 illustrates this early replacement cost.

In summary, the revenue requirement method using the spreadsheet format is easy to follow and can be applied to transformer replacement problem.

Table 5.2: Spreadsheet of annual revenue requirement

Year, k	UI_k	D_{Bk}	T_k	CC_k	COL_k	RR_k
1	$400,000	$12,000	$44,800	$107,600	$46,900	$154,500
2	$388,000	$12,000	$43,456	$104,732	$46,900	$151,632
3	$376,000	$12,000	$42,112	$101,864	$46,900	$148,764
4	$364,000	$12,000	$40,768	$98,996	$46,900	$145,896
5	$352,000	$12,000	$39,424	$96,128	$46,900	$143,028
6	$340,000	$12,000	$38,080	$93,260	$46,900	$140,160
7	$328,000	$12,000	$36,736	$90,392	$46,900	$137,292
8	$316,000	$12,000	$35,392	$87,524	$46,900	$134,424
9	$304,000	$12,000	$34,048	$84,656	$46,900	$131,556
10	$292,000	$12,000	$32,704	$81,788	$46,900	$128,688
11	$280,000	$12,000	$31,360	$78,920	$46,900	$125,820
12	$268,000	$12,000	$30,016	$76,052	$46,900	$122,952
13	$256,000	$12,000	$28,672	$73,184	$46,900	$120,084
14	$244,000	$12,000	$27,328	$70,316	$46,900	$117,216
15	$232,000	$12,000	$25,984	$67,448	$46,900	$114,348
16	$220,000	$12,000	$24,640	$64,580	$46,900	$111,480
17	$208,000	$12,000	$23,296	$61,712	$46,900	$108,612
18	$196,000	$12,000	$21,952	$58,844	$46,900	$105,744
19	$184,000	$12,000	$20,608	$55,976	$46,900	$102,876
20	$172,000	$12,000	$19,264	$53,108	$46,900	$100,008
21	$160,000	$12,000	$17,920	$50,240	$46,900	$97,140
22	$148,000	$12,000	$16,576	$47,372	$46,900	$94,272
23	$136,000	$12,000	$15,232	$44,504	$46,900	$91,404
24	$124,000	$12,000	$13,888	$41,636	$46,900	$88,536
25	$112,000	$12,000	$12,544	$38,768	$46,900	$85,668
26	$100,000	$12,000	$11,200	$35,900	$46,900	$82,800
27	$88,000	$12,000	$9,856	$33,032	$46,900	$79,932
28	$64,000	$12,000	$8,512	$30,164	$46,900	$77,064
29	$52,000	$12,000	$7,168	$27,296	$46,900	$74,196
30	$40,000	$12,000	$5,824	$24,428	$46,900	$71,328
					$\overline{RR}$ =	**$133,567**
					CCR =	**$1,113,058**

Table 5.3: Spreadsheet of annual revenue requirement with early replacement

Year	UI_k	D_{Bk}	T_k	CC_k	COL_k	RR_k
1	$400,000	$12,000	$44,800	$107,600	$46,900	$154,500
2	$388,000	$12,000	$43,456	$104,732	$46,900	$151,632
3	$376,000	$12,000	$42,112	$101,864	$46,900	$148,764
4	$364,000	$12,000	$40,768	$98,996	$46,900	$145,896
5	$352,000	$12,000	$39,424	$96,128	$46,900	$143,028
						+$352,000
						-$12,000
						-$40,000
						=$443,028
6	New transformer's data is used for calculation beginning from year 6th					
7						
8						
9						
10						

6. Optimization Strategy for Transformer Procurement and Replacement

6.1 Introduction

Sizing of power transformers or replacement of existing transformers is done intuitively from simplified technical and/or economical decisions. Combining both technical and economic considerations, however, is more desirable. In this research, a new method is proposed for utilities to be able to maximize the optimal use of their existing transformers, to select the appropriate transformer size and to determine the replacement strategy. A number of situations in real world deal with transformer procurement and replacement, such as, (i) select a new transformer for a new project (*new design*), (ii) delay transformer replacement until its life ends (*delay replacement option*), and (iii) replace the existing transformer immediately with a larger unit (*replace now option*). The life of the transformer for all problems depends on its size, loading and load growth rate. The delay replacement option defers new investment, however, with the sacrifice of transformer's life and higher cost of losses.

In this chapter, a new optimization scheme is proposed, that utilizes the probability tree load-growth structure to take care of overloading risks and replacement timing. Only the IEEE Clause 7 thermal (simplified) model from Chapter 3 is applied here due to limitation of available transformer data. However, Annex G model can easily be used provided there are available transformer data. The cost of random failure of a transformer in-service is also included in the scheme. It is assumed that transformer cost and losses can be formulated into some continuous function depending upon transformer sizes. However, the actual cost and loss data, if available, can also be used with some modification. The cost and loss data are derived from forced-air cooled (FA) transformers. For other cooling types, similar data could be added and left for future work. The thermal model and hottest-spot temperature (Chapter 3) determine the remaining life of the transformer.

6.2 Transformer Cost and Losses Function

For oil-cooled (OA/FA/FA) transformers utilized in large distribution substations ranging between, say 10-100 MVA (the primary voltage of 69 kV, 115 kV or 230 kV, and the secondary voltage rated at 12.47 kV to 34.5 kV), the cost depends on a number of factors. The key factors are: the HV side voltage and the corresponding Basic Insulation Level (BIL) and the losses. The data given in Table 6.1 is for typical (OA/FA/FA) transformers. The installation cost of \$595/MVA [45] including labor and equipment is also added to the transformer cost. A curve-fitting program utilizes a quadratic function ($f(S_T)$) to estimate the cost of transformers. These data points are plotted in Figure 6.1 and the transformer cost is approximated as:

$$f(S_T) = K_2 S_T^2 + K_1 S_T + K_0 \qquad (\$/\text{MVA}) \qquad (6.1)$$

$$= 8.453 S_T^2 - 862.9 S_T + 33164$$

Where, K_0, K_1, and K_2 are constants and S_T is the transformer size (highest rating) in MVA (65°C average winding temperature rise and 110°C hottest-spot temperature).

The 65°C ratings in Table 6.1 are calculated using common multiplying factors. The typical multiplying factor to convert MVA rating at 55°C winding rise to MVA rating at 65°C winding rise are given in

Table 6.2. It is clear from

Figure 5.1 that the transformer cost function ($/MVA) decreases as transformer rating increases and reaches approximately a constant value at around 50MVA and higher rating.

Table 6.1: Cost of typical forced-air cooled (OA/FA/FA) power transformer

S_T, MVA		Transformer Cost		
55°C	65°C	Transformer, $	Installation, $	$/MVA*
10	11	277,000	6,500	24,652
20	23	395,000	13,700	17,770
25	28.75	429,000	17,100	15,516
40	46	486,000	27,400	11,160
50	57.5	605,000	34,200	11,116

* $/MVA is based on 65°C winding rise rating.

Table 6.2: The multiplying factor for MVA rating conversion from 55°C winding rise to 65°C winding rise rating

Cooling Type	Multiplying Factor
OA	1.165
FA	1.150
NDFOA	1.140
FOA	1.125

Note: Tables 6.1 and 6.2 are calculated based on typical top-oil and hottest-spot temperature rise and a loss ratio of approximately 3.0.

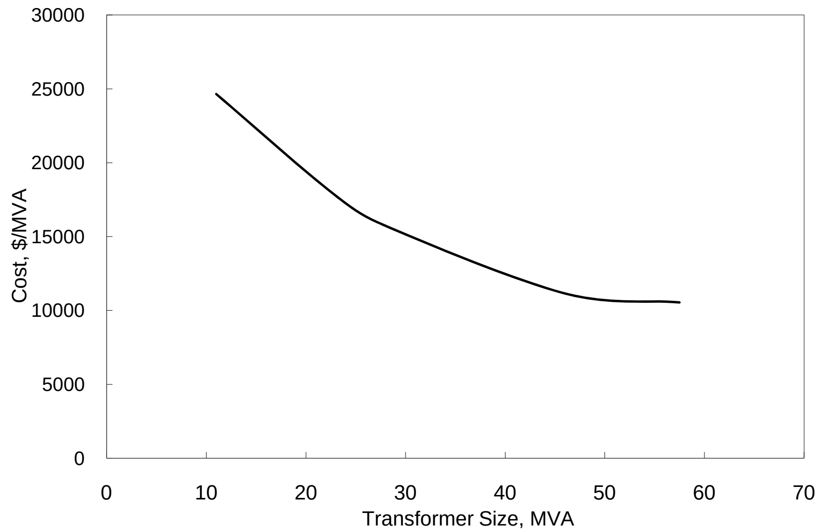

Figure 6.1: Transformer cost data

No-load and load losses also vary by transformer sizes and designs. Since these values are extremely important quantities, it is recommended that actual values from the manufacturers be used. Typical losses in kW/MVA are tabulated in

Table 6.3. The quadratic equations are developed to fit the curve and the no-load and load losses in kW/MVA can be found from equation (6.2) and (6.3), respectively.

$$f_{NLL}(S_T) = (6.216 \times 10^{-5})S_T^2 - 0.01219 S_T + 1.523 \qquad (6.2)$$

$$f_{LL}(S_T) = 0.0002657 S_T^2 - 0.0524 S_T + 4.969 \qquad (6.3)$$

Table 6.3: Transformer losses

S_T, MVA		No-load losses		Load losses		Loss Ratio (R)
55°C	65°C	kW**	kW/MVA*	kW**	kW/MVA*	
10	11.5	17	1.48	53	4.61	3.12
20	23	29	1.26	86	3.74	2.97
30	34.5	40	1.15	115	3.33	2.88
40	46	50	1.09	141	3.06	2.82
50	57.5	60	1.04	165	2.87	2.75
60	69	70	1.01	188	2.72	2.69
80	92	87	0.95	232	2.52	2.67
100	115	106	0.92	272	2.36	2.57

* kW/MVA is based on 65°C average winding rise rating.

** kW is based on 65°C average winding rise rating.

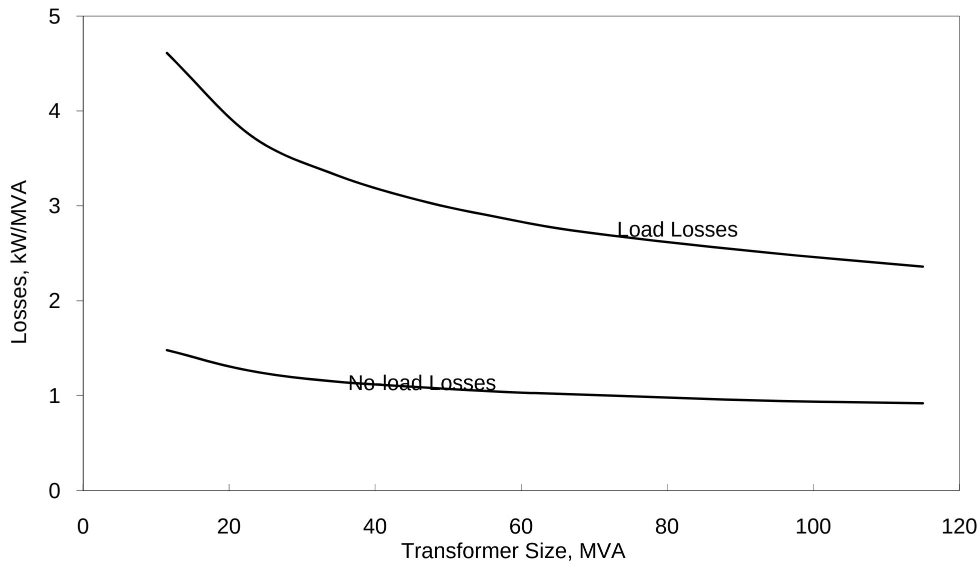

Figure 6.2: Transformer losses data

6.3 Random Failure of Transformer In-Service

Transformers may fail at random during its normal life, and it costs utilities to purchase a new unit. A typical hazard function, *h(t)*, describing this random failure, also known as "bathtub curve" [46], is plotted in Figure 6.3.

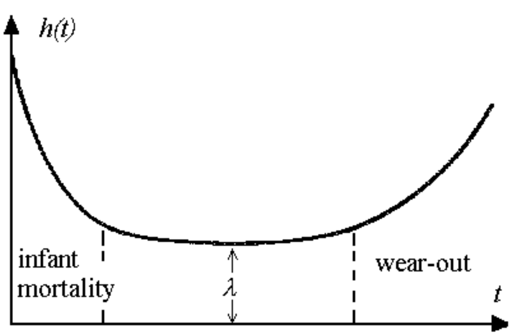

Figure 6.3: "Bathtub curve"

It is believed that the distribution of failure, *f(t)*, during the normal operating period is an exponential decay and the hazard function is constant, as derived by[46].

$$h(t) = \frac{f(t)}{1 - F(t)}$$

$$f(t) = \lambda e^{(-\lambda t)}$$

$$F(t) = \int_0^t f(t)dt = 1 - e^{(-\lambda t)}$$

$$h(t) = \frac{\lambda e^{(-\lambda t)}}{1-(1-e^{(-\lambda t)})} = \lambda$$

where: *f(t)* is exponential distribution function
F(t) is exponential cumulative distribution function
λ is the failure rate, and
t is the time.

When transformers are subjected to a random failure rate of λ, utilities need additional revenue to cover the cost of transformer failure. It can be formulated as:

$$CF_k = \lambda \cdot C_{TR} \cdot (N_{\exp} - k) / N_{\exp} \qquad ; \text{for } 1 < t \le N_{\exp} \qquad (6.4)$$

where: CF_k is the cost of failure in year *k*
C_{TR} is the cost of transformer in dollars
$N_{\exp}$ is expected transformer life in year, and
k is the year that transformer fails

The failure rate of the transformer is reported[47] to be about 0.2-0.5%.

6.4 Expected Transformer Life

It has been discussed earlier that, in this research the normal transformer life (1 pu) of 150,000 hours (17.12 years) is used. This corresponds to the insulation's tensile strength reduction to 20% of its original value or the insulation's degree of polymerization reduction to 200. Based on these criteria, the remaining transformer life expectancy for the cyclic load is calculated. A computer program is written to calculate the loss-of-insulation life of the transformer subjected to cyclic load. Typical monthly load profiles and ambient temperature profiles as shown in Appendix B are used. In a real power system, the actual load profiles may be obtained from SCADA. The actual ambient temperature profile can be obtained from the weather station data at the transformer location or installed on-line monitoring devices. Table 6.4. is from the test run for a 52.26 MVA forced-air cooled (OA/FA/FA) transformer with typical load and ambient temperature profiles. The transformer data used in this test case is obtained from reference [1]. The annual peak load in the month of August is assumed to be 1.1 per-unit. The assumed August load and ambient temperature profile is repeated again in Figure 6.4. The load is assumed to grow at a constant rate of 2.5% compounded annually. The thermal model used corresponds to the IEEE Annex G. (or the Detailed Model).

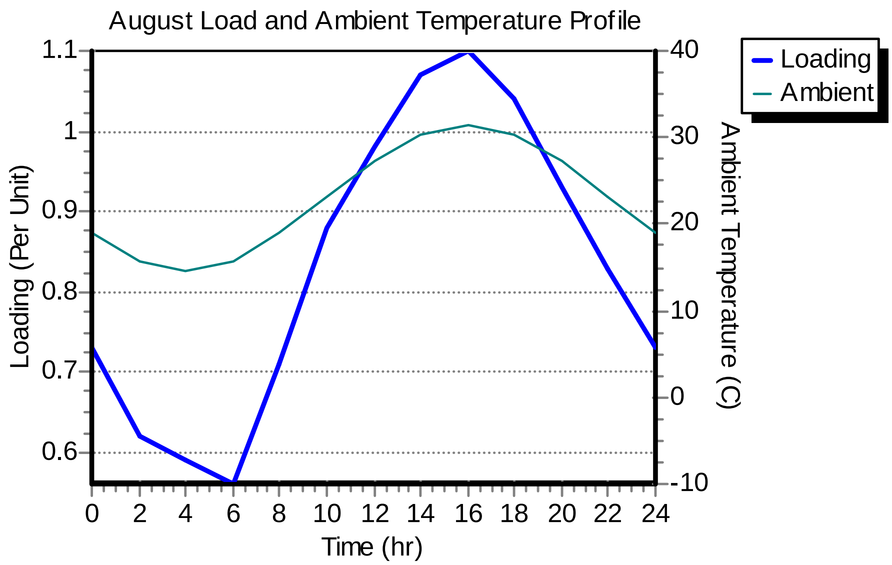

Figure 6.4: Load and ambient temperature profiles in the month of August

Table 6.4: Illustrated life cycle study printout of transformer life

Transformer Thermal Loading Program
Life Cycle Study of Transformer using IEEE Annex G Thermal Model

Year 2001

	% Loss of Life	Remain Tensile	Remain DP	Max. Hot Spot	Max. Top Oil	Acc. %LOF	Used Life(yrs)
January	0.000	97.05	1400	59.9	42.8	0.000	0.00
February	0.001	97.05	1400	68.7	50.2	0.001	0.00
March	0.002	97.04	1400	74.5	53.9	0.004	0.00
April	0.002	97.04	1400	75.4	54.8	0.006	0.00
May	0.007	97.03	1399	84.5	61.7	0.013	0.00
June	0.035	96.98	1397	99.0	74.5	0.048	0.01
July	0.239	96.61	1382	118.2	89.0	0.287	0.05
August	0.292	96.17	1365	120.2	91.1	0.579	0.10
Sept.	0.033	96.12	1363	98.5	74.0	0.612	0.10
October	0.010	96.10	1362	87.5	64.8	0.621	0.11
Nov.	0.005	96.09	1362	82.3	59.5	0.627	0.11
Dec.	0.002	96.09	1362	72.3	51.6	0.628	0.11

Maximum Loading= 1.100   Used Life= 0.11 years(942 hrs)

Year 2012

	% Loss of Life	Remain Tensile	Remain DP	Max. Hot Spot	Max. Top Oil	Acc. %LOF	Used Life(yrs)
January	0.007	28.94	261	85.0	59.1	76.589	13.11
February	0.025	28.93	261	97.3	68.7	76.614	13.12
March	0.074	28.89	261	107.4	75.1	76.688	13.13
April	0.080	28.86	260	108.3	76.1	76.767	13.15
May	0.293	28.72	259	121.7	85.9	77.060	13.20
June	1.602	28.00	255	140.1	101.8	78.663	13.47
July	16.032	21.74	212	168.5	123.3	94.695	16.21
August	18.911	16.12	171	170.6	125.5	113.605	19.45
Sept.	1.519	15.74	168	139.6	101.2	115.124	19.71
October	0.384	15.65	168	124.7	89.1	115.508	19.78
Nov.	0.223	15.59	167	119.4	83.6	115.731	19.82
Dec.	0.058	15.58	167	105.1	72.8	115.789	19.83

Maximum Loading= 1.443   Used Life= 19.83 years(173683 hrs)

The transformer used, in the first year of service, is just 0.11 years of its normal life (17.12 years). The transformer lost most of its life in July and August due to higher load level and higher ambient temperature. The load shape is assumed to be unchanged in our study for simplification. It is then multiplied by the load growth factor (1+load growth rate in decimal) for each consecutive year. Any daily and seasonal variations can be used to calculate the loss-of-life. The load growth increases the peak load and the loss-of-life sharply especially at later years before transformer life ends. The transformer life is considered to reach the end when remaining tensile strength reaches 20% of its original value or when the degree of polymerization reaches 200. The initial degree of polymerization of the new insulation is assumed to be 1400. The equations for calculation of remaining tensile strength and degree of polymerization are given in Chapter 2. Figure 6.5-Figure 6.8 are the plots from the program.

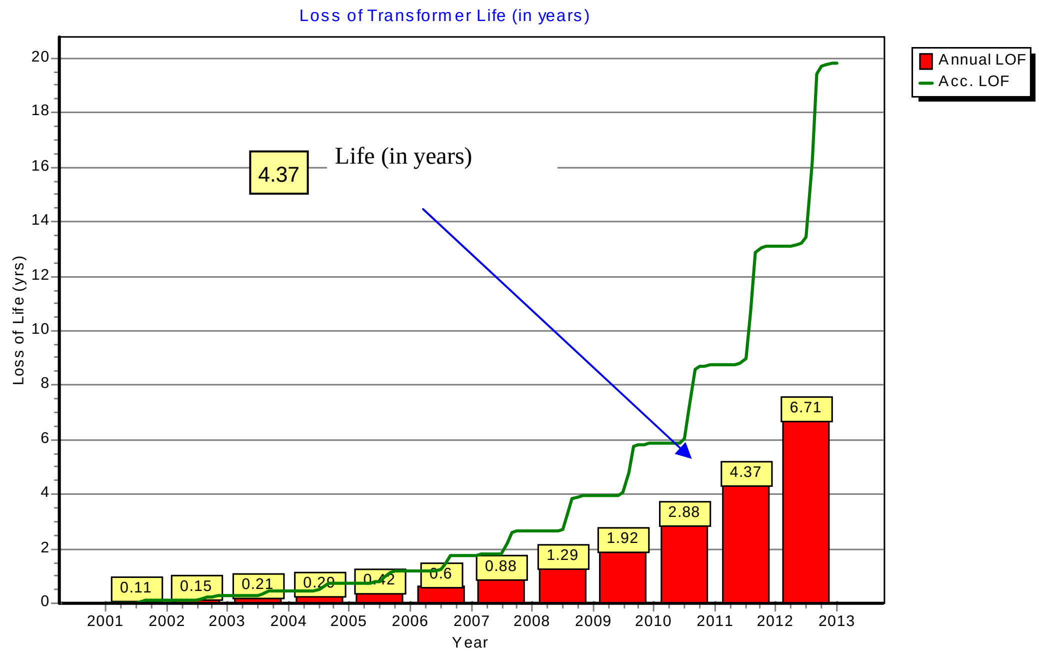

Figure 6.5: Loss of transformer life vs. years in service

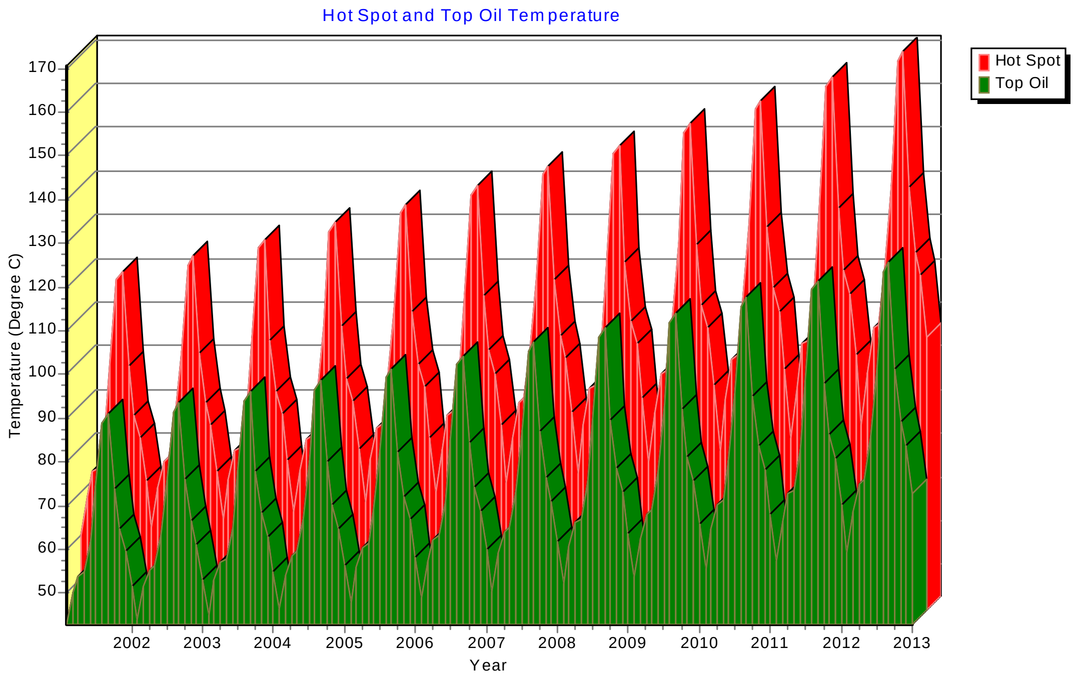

Figure 6.6: Hottest-spot and top-oil temperature vs. years in service

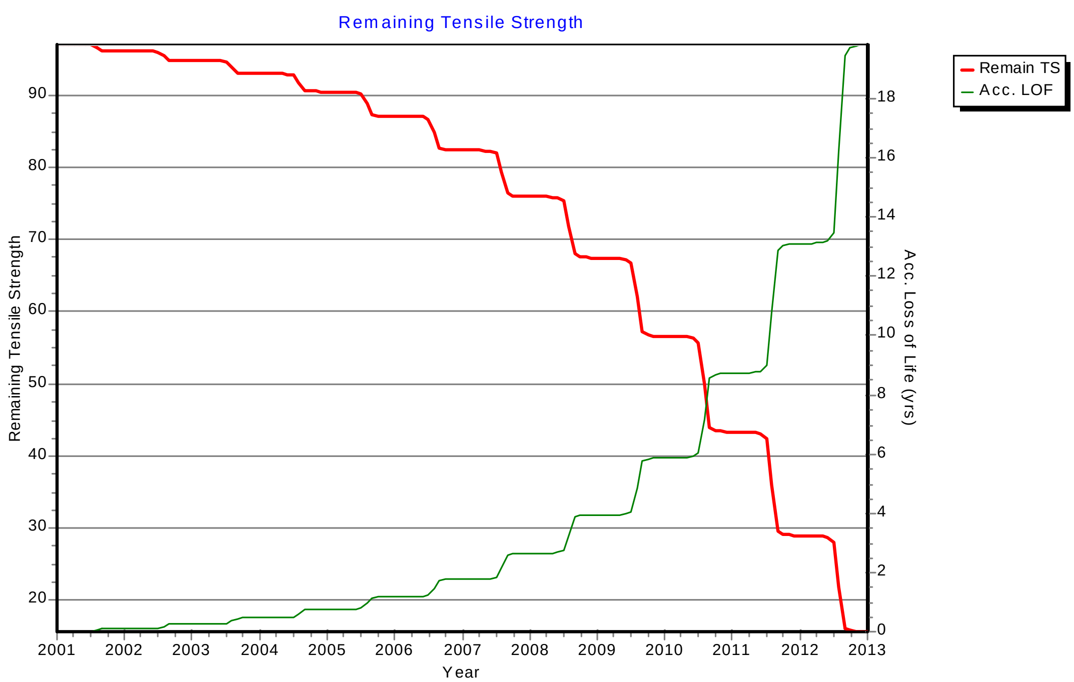

Figure 6.7: Insulation's remaining tensile strength vs. years in service

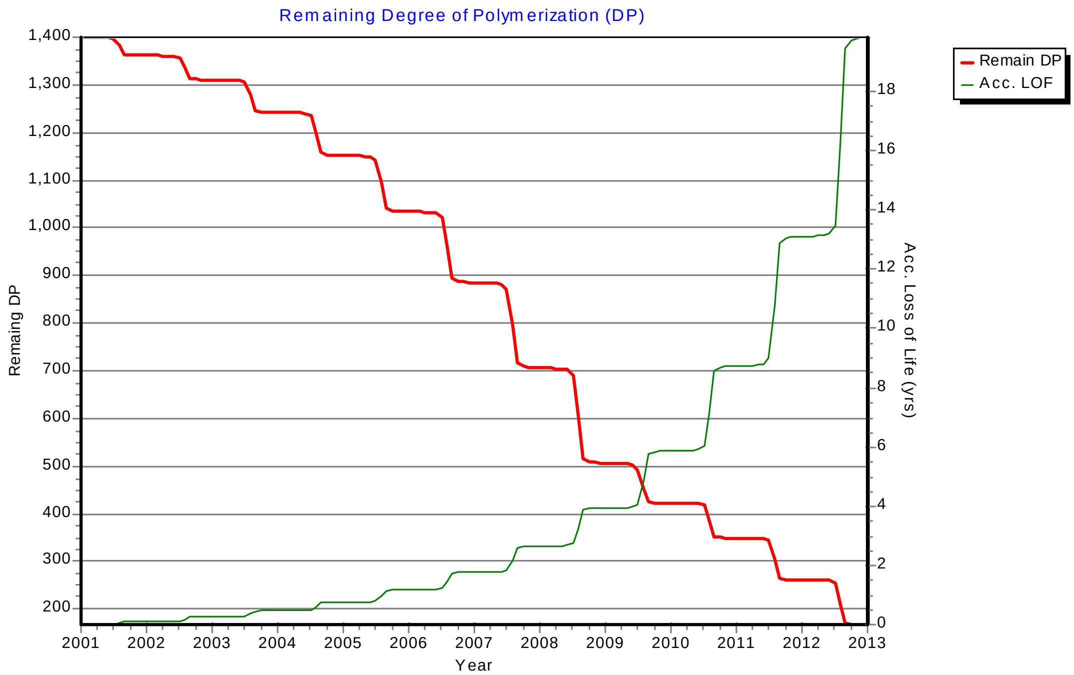

Figure 6.8: Insulation's remain degree of polymerization vs. years in service

It is clear from Table 6.4 that in this example, the expected transformer life is approximately 11 years and 7 months. This shorter service life results from the 2.5% annual load growth and high initial annual peak load in the month of August. The top-oil and hottest-spot temperature exceeds limits of 110°C and 140°C respectively.

6.5 Load Growth Uncertainty Modeling

Transformer life expectancy is closely related to its present load and the future load growth rate. In the previous example, a fixed load growth of 2.5% (compounded annually) is used. As shown in Table 6.4, in the first year of service, the transformer just used 0.11 years from its normal life expectancy. However, it consumed 6.71 years of life in the last year of operation. Actual transformer loading and the prediction of the future load growth rate has a lot of uncertainties. In this research, the probability tree method is utilized to take into account these uncertainties. An alternate approach is to utilize the technique of Monte Carlo simulations. Probability tree method is simple to follow, however, computationally expensive.

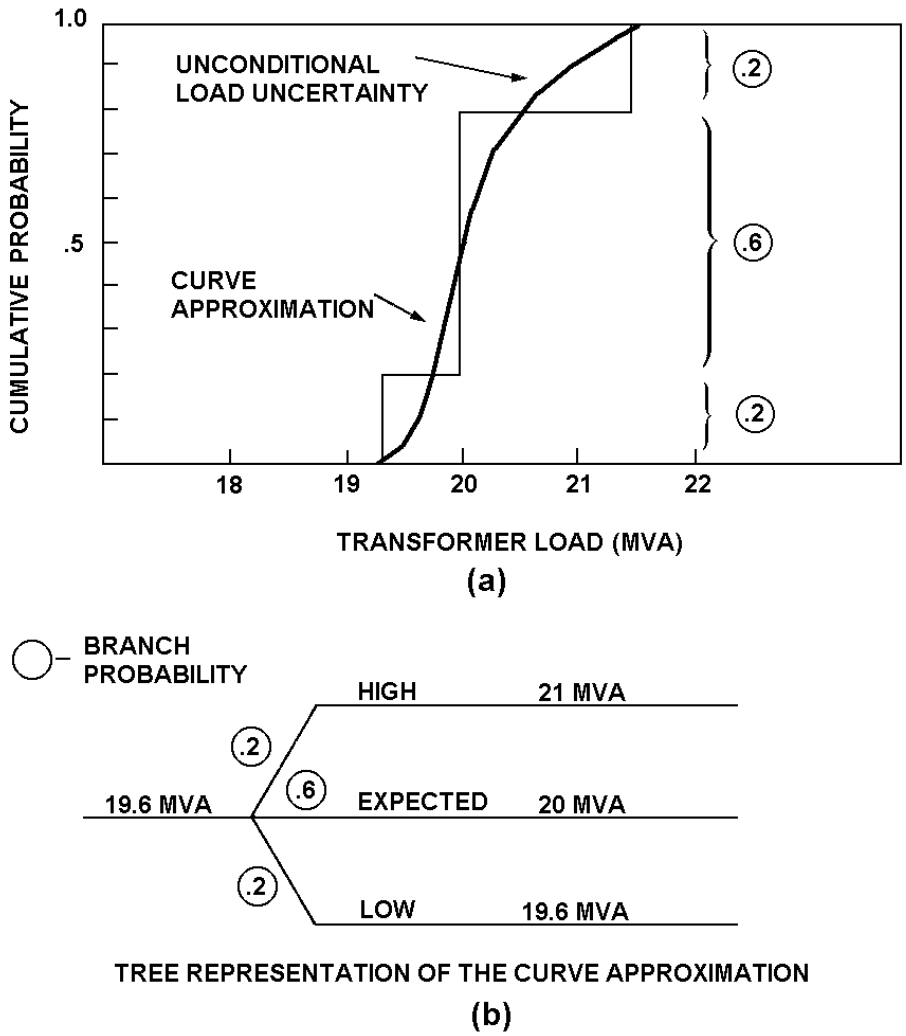

Figure 6.9: Approximating load uncertainty using probability tree

Figure 6.9 shows a construction of a probability tree from the probability curve. The smooth probability curve, in this example, has been discretized into three pieces. The expected load (20 MVA) is assumed to have a probability of 0.6. Both the higher (21 MVA) and the lower (19.6 MVA) loads have a probability of 0.2. The number in the circle in Figure 6.9(b) is the probability of the load that follows the value. All loadings are selected randomly.

Figure 6.10 illustrates an example of the probability tree beginning. The tree grows by a power of 3 for every year. As such when the time progresses by 4 years, the load can grow into 81 (=3^4) different paths. The assessment of load growth rate beyond 81 different paths can be tedious and repetitive. In order to simplify the problem, the probability tree is limited to 4 years of study. After the 4th year the load growth rate is assumed to be constant.

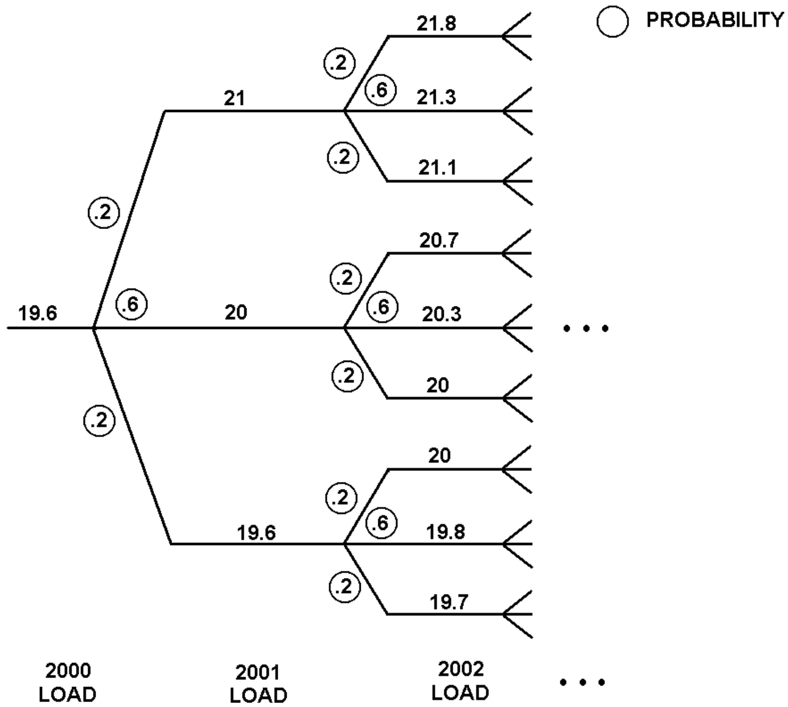

Figure 6.10: Probability tree representation of load uncertainty

Figure 6.11 shows load growth paths. Path 1 is the highest possible growth and the probability of path 1 is the product of all the probabilities along its path from year 1st to 4th , which is

$$P_{r,1} = (0.2)(0.2)(0.2)(0.2) = 0.0016$$

In the same way, the probability of path 5 is

$$P_{r,5} = (0.2)(0.2)(0.6)(0.6) = 0.0144$$

The summation of all probabilities of all paths is equal to 1.0, i.e.,

Mathematically, $$\prod_{i=1}^{81} P_{r,i} = 1.0$$

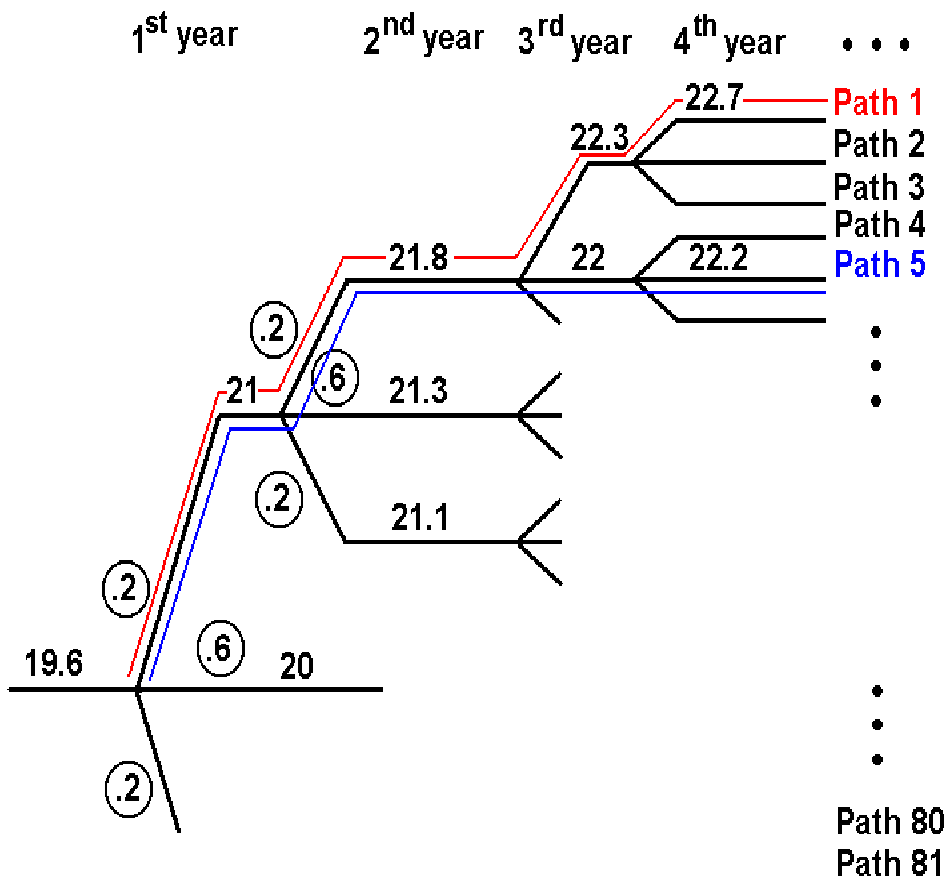

Figure 6.11: Illustration of load growth path

Beginning 5th year, the load growth rate is assumed to be a constant value of α. Mathematically, load at year k (L_k) is

$$L_k = L_4(1+\alpha)^{k-4} \qquad (6.5)$$

Where, k is year number ($k \geq 5$), L_4 is the load at the end of probability tree table (4th year), and α is the load growth rate in decimal.

Figure 6.12 illustrates the fact that the degree of uncertainty widens as the year progresses. The curve on year 2001 is more vertical because of better prediction of uncertainty (less number of paths). The high and low predicted load is close to the expected value. The compounded growth on high and low branches (Figure 6.9(b)) of probability tree spread out the high and low boundary of the projected load. Figure 6.13 shows the projection of load uncertainty for a long period. Figure 6.13 displays probability distribution of load, whereas, Figure 6.12 shows cumulative distribution of load.

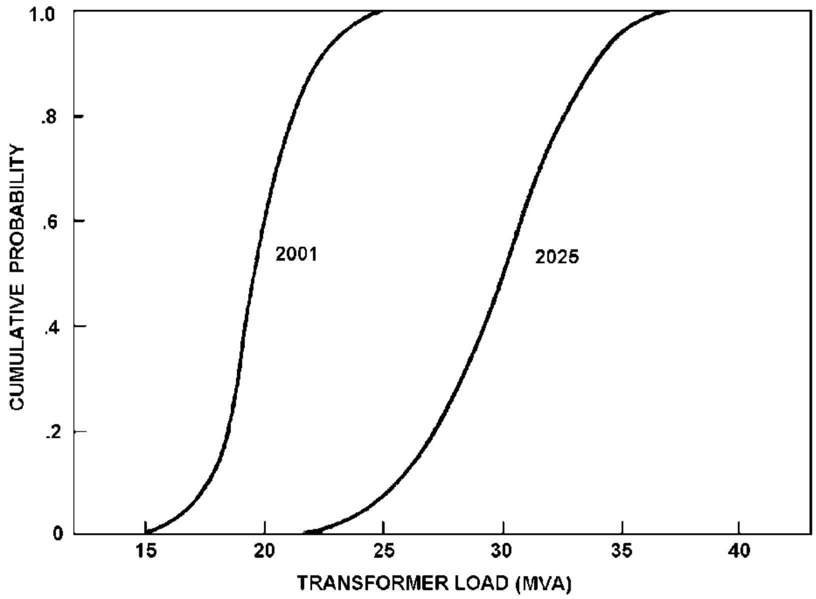

Figure 6.12: Cumulative probability of transformer load

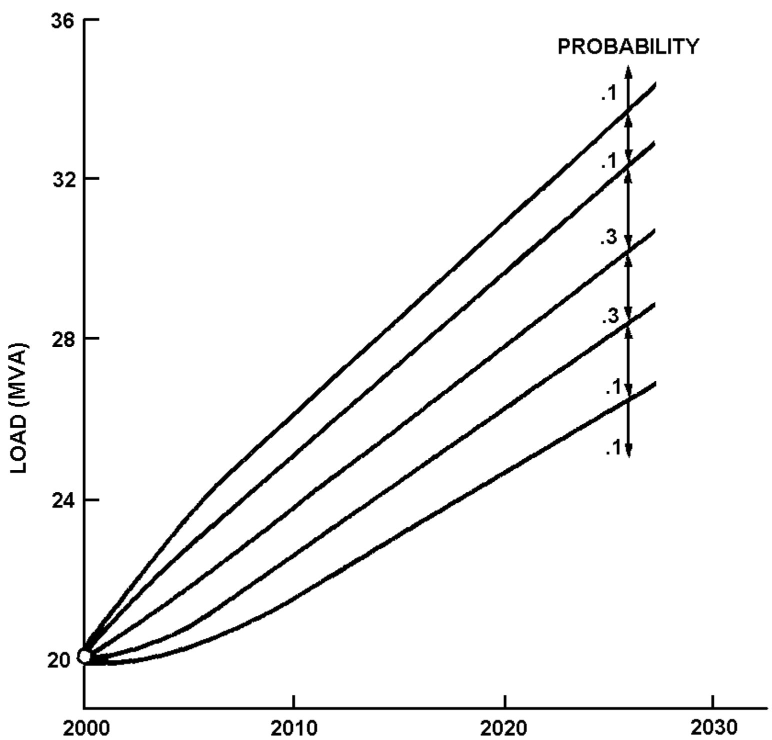

Figure 6.13: Approximating load uncertainty in each future year

With 81 different load growth paths, the levelized revenue requirements (discussed in Chapter 5) are calculated for each path. Then, the equivalent levelized revenue requirement (ERR) is calculated by weighting levelized revenue requirement with path probability as

$$ERR = \sum_{p=1}^{81} \mathrm{P}_{\mathrm{r},p} \cdot \overline{RR}_p \tag{6.6}$$

Where, p is path number, $\mathrm{P}_{\mathrm{r},p}$ is probability of path p, and $\overline{RR}_p$ is levelized revenue requirement of path p.

Along with each load growth path, a new transformer is required when existing transformer has expended its useful life to the thermal loading. This will add additional investment for the utilities at some future year as predicted by the thermal loading described in Chapter 3.

6.6 Solution Methods

A program is written to solve the optimization problem, where the objective function is the minimization of the equivalent levelized revenue requirement (ERR):

$$\min ERR = \min \sum_{p=1}^{81} \mathrm{P}_{\mathrm{r},p} \cdot \overline{RR}_p$$

The block diagram of the complete solution is shown in Figure 6.14. The diagram includes the combination of transformer model and utilities financial model. The program uses the IEEE classical model (Clause 7). By using information from transformer manufacturers and utilities, the transformer cost and losses are calculated from equations (6.1), (6.2), and (6.3). The program assumes that the transformer size can vary continuously. One MVA incremental step is used. In order to simplify the computation, the historical load and ambient temperature profiles have been applied on monthly basis. Twelve load profiles and twelve ambient temperature profiles (one for each month) are stored in the database. The annual peak load has been generated from the probability tree structure that derived from short-term (4 years) load forecast.

The transformer thermal model calculates remaining transformer life by annual cyclic loading. If the transformer reaches the end of its life (150,000 hrs.), the new transformer has to be installed. Criterion for the new transformer size is based on the study method. For a new design and replace now option, the new transformer size is set to have the same initial annual per unit peak load of the existing transformer when it was installed. For the delay replacement option, the existing transformer has been used until the end of its life and then replaced with different size of a new transformer ranging from 0.5 - 1.0 per unit peak loading of its first year of operation. In the case of delay replacement study, the remaining life of the existing transformer has to be pre-calculated by backward thermal loading available in the program or direct measurement from actual insulation remaining strength. The transformer thermal model also calculates the annual cost of losses of the transformer as:

$$COL_k = CNLL_k + CLL_k$$

$$CNLL_k = DC_k \cdot P_{core} + EC_k \cdot \int_{t=0}^{8760} P_{core} dt$$

$$CLL_k = DC_k \cdot PRF \cdot P_{cu,\max} + EC_k \int_{t=0}^{8760} P_{cu}(t) dt$$

where: COL_k, $CNLL_k$, and CLL_k are the cost of losses, cost of no-load losses, and cost of load losses in year, k respectively

DC_k is demand charge, \$/kW

EC_k is cost of energy, \$/kWh

P_{core} is core or no-load losses, kW

$P_{cu}(t)$ are copper or load losses, kW

$P_{cu,\max}$ are the annual peak load losses

PRF is peak responsibility factor (See Chapter 4)

The cost of transformer random failure is calculated from equation (6.4). The utilities financial model uses the following financial data as an input to calculate carrying charge, tax and depreciation (Chapter 5).

Equity return rate (i_e)

Borrowed money rate (i_b)

Debt ratio (λ)

Tax rate (i_t)

Depreciation method (only “Straight Line” method is used in this report.)

Accounting book life of transformer is assumed (30 years).

The revenue requirement for year k can then be written as:

$$RR_k = CC_k + COL_k + CF_k$$

The program calculates revenue requirement of each load growth path. Each load growth path is 30 years in length. The levelized revenue requirement can be found by using equation (5.24). The final equivalent levelized revenue requirement is then calculated from the probability weighting on levelized revenue requirement for 81 different paths.

The various transformer sizes are generated by computer program. The program calculates each equivalent levelized revenue requirement for each transformer. The minimum equivalent levelized revenue requirement determines the best alternative.

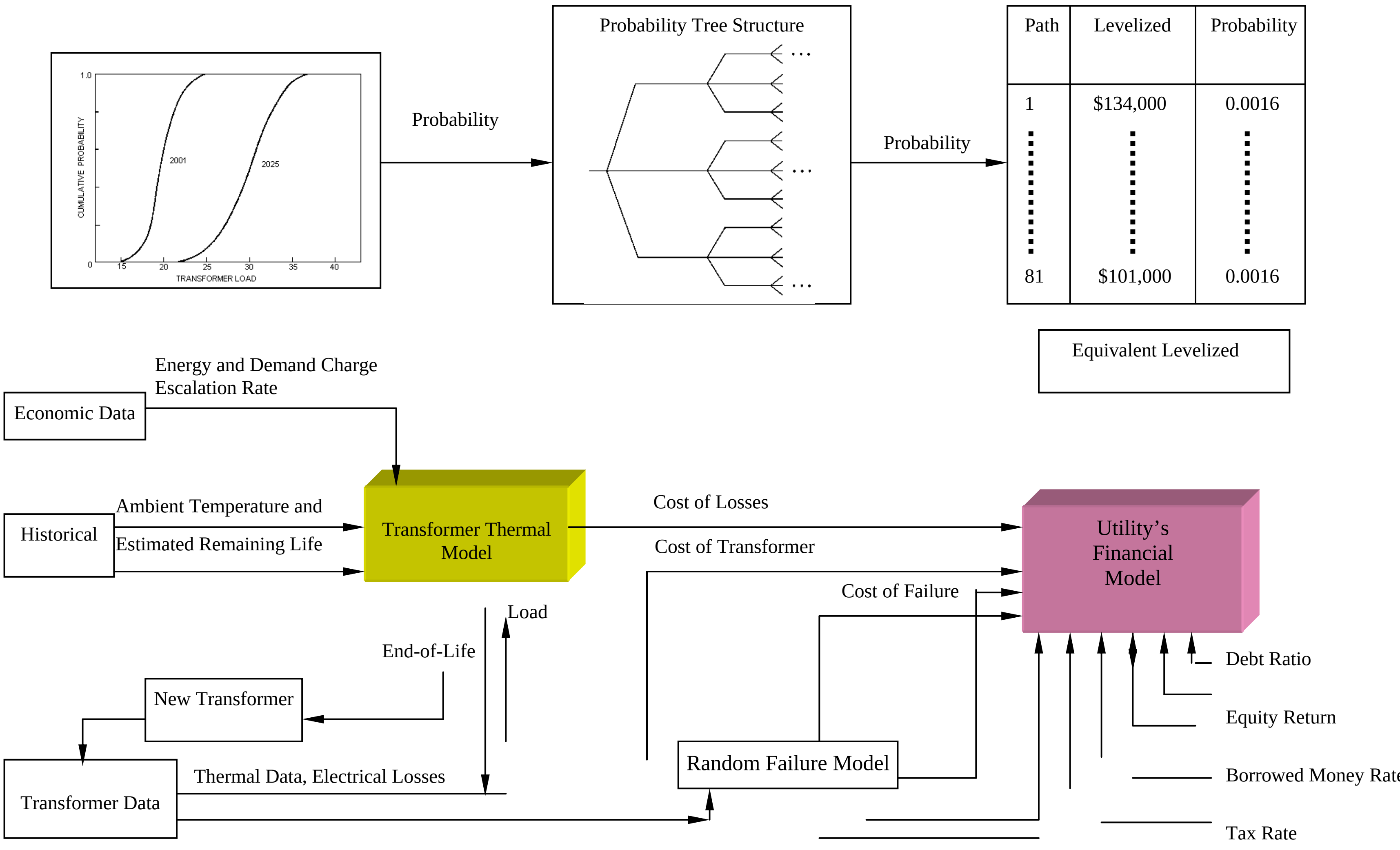

Figure 6.14: Integrated structure of insulation degradation based transformer utilization mode

7. Simulations and Case Studies

7.1 Introduction

The program incorporated thermal model, loss-of-life calculation, failure cost, replacement criterion, and economic evaluation. Two case studies are discussed and one possible scenario: the medium load growth rate of 1.75% /year with +0.25% and –0.75% deviation. After the 4th year, a constant load growth rate of 2%/year has been assumed.

- *Case #1*, a transformer has to be purchased for a new project. The existing load at the beginning is estimated at 20MVA. The growth rate is medium at 1.75% per year. A study period of 30 years has been used in the simulations.

- *Case #2*, the existing transformer size is assumed to be 18 MVA (highest rating). It is assumed to be in service for 25 yrs. with an estimated remaining life of 25% (or 0.25pu.). The load growth rate is assumed at 1.75%. There are two choices: (i) Continue overload the transformer, until the life is completely utilized and then replace appropriately and optimally sized to accommodate the load growth. The end-of-life criteria used are 20% RTS or remaining DP of 200. The program evaluates the size. It is assumed that the load on the new transformer when it is commissioned is 0.5, 0.6, 0.7, 0.8, 0.9, and 1.0 per-unit load. As an example, if the existing transformer's life ends at the end of year 5th and the next year (6th) load is 22.46 MVA, with the sizing criteria of 0.5, the size of the new transformer is selected as 44.92 MVA (= 22.46/0.5).

7.2 Solutions to the Problems

Results of the two cases are presented here, utilizing similar transformer design (except for the MVA output), economic model, and financial data are tabulated in Table 7.1. The MVA rating corresponds to 65°C average winding temperature rise.

Table 7.1: Common transformer, economic, and financial data for all case studies

Top-oil rise over ambient at rated load = 45.0°C Hottest-spot rise over top oil at rated load = 35.0°C Oil time constant = 1.25 hours Winding time constant = 5.0 minutes Cooling mode is FA
Energy cost = 0.035 $/kWh Energy escalation rate = 2.0% Demand charge = 120 $/kW-yr Demand charge escalation rate = 2.0% Peak Responsibility Factor (*PRF*) = 0.8
Random failure rate = 0.5% Return on equity rate = 16.0% Borrowed money rate = 5.0% Debt ratio = 0.5 Tax rate = 50% Market (Salvage) value = 10% of investment cost Inflation rate = 0% Transformer book life = 30 years
Existing transformer size = 18MVA Year in service = 25 years Remaining life = 0.25 per unit Existing transformer price = $340,000 Market value of existing transformer price = $34,000

7.2.1 Case #1, Sizing of a New Transformer with Moderate Load Growth

In this case, a new transformer is to be installed for a project. The load growth rate is assumed moderate. The first four years of load growth is constructed using the probability tree with the high, expected, and low load growth rate of 2.0, 1.75, and 1.0 %, respectively. Based on the loading information, a transformer size between 20 to 40 MVA is considered. Table 7.2 lists Equivalent Revenue Requirement (ERR) for each size. The ERR reaches minimum of $114,625 for the transformer size of 25 MVA. Accordingly, 25 MVA is the most economical size for this project. The first year's annual peak load of this new transformer is 0.81 per unit (= 20.35/25).

Table 7.3 shows the detailed result and the economic evaluation of a 25 MVA transformer on the most probable load growth path #41 from the life cycle study performed on this transformer. With this load growth pattern of path #41, the 25MVA transformer can last approximately 30 years. The simulation result is shown in Table 7.4. Figure 7.1 shows the temperature profiles.

The maximum hottest-spot and top-oil temperature at 30th year is 167.8°C, 105.7°C respectively. The hottest-spot temperature is too high and may cause bubble generation and dielectric strength reduction during the overload period.

Table 7.2: Result of Case #1 Study

Sizing Program on new application only

Top-oil rise over ambient at rated load = 45.0 C
Hottest-spot rise over top oil at rated load = 35.0 C
Oil time constant = 1.25 hours
Winding time constant = 5.0 minutes
Cooling mode is FA

Equivalent Revenue Requirement(ERR)

Size	ERR
20.00	$120,426
21.00	$118,901
22.00	$117,486
23.00	$116,327
24.00	$115,375
25.00	$114,625
26.00	$114,827
27.00	$115,050
28.00	$115,294
29.00	$115,558
30.00	$115,842
31.00	$116,148
32.00	$116,480
33.00	$116,840
34.00	$117,234
35.00	$117,666
36.00	$118,140
37.00	$118,663
38.00	$119,241
39.00	$119,879
40.00	$120,584

Table 7.3: Result of a 25 MVA transformer on load growth path #41, case #1 study

25.00MVA Path No.41

Year	MVA	UIk	Tk	CCk	COLk	CFk	RRk
1	25.00	421866	33749	90701	28089	0	118791
2	25.00	409210	32737	88360	29180	1969	119508
3	25.00	396554	31724	86018	30321	1898	118238
4	25.00	383898	30712	83677	31518	1828	117023
5	25.00	371242	29699	81336	32861	1758	115954
6	25.00	358586	28687	78994	34274	1687	114956
7	25.00	345930	27674	76653	35762	1617	114032
8	25.00	333274	26662	74312	37329	1547	113187
9	25.00	320618	25649	71970	38979	1477	112426
10	25.00	307962	24637	69629	40717	1406	111752
11	25.00	295306	23624	67288	42549	1336	111173
12	25.00	282650	22612	64946	44480	1266	110692
13	25.00	269994	21600	62605	46516	1195	110316
14	25.00	257338	20587	60264	48662	1125	110051
15	25.00	244682	19575	57922	50926	1055	109903
16	25.00	232026	18562	55581	53314	984	109879
17	25.00	219370	17550	53239	55834	914	109987
18	25.00	206714	16537	50898	58493	844	110235
19	25.00	194058	15525	48557	61299	773	110630
20	25.00	181402	14512	46215	64262	703	111181
21	25.00	168746	13500	43874	67391	633	111898
22	25.00	156090	12487	41533	70695	562	112790
23	25.00	143434	11475	39191	74185	492	113868
24	25.00	130778	10462	36850	77871	422	115143
25	25.00	118122	9450	34509	81766	352	116626
26	25.00	105466	8437	32167	85882	281	118331
27	25.00	92810	7425	29826	90233	211	120270
28	25.00	80154	6412	27485	94831	141	122456
29	25.00	67499	5400	25143	99693	70	124906
30	25.00	54843	4387	22802	104833	0	127635

Levelized Revenue Requirement = $114,817

Table 7.4: Life cycle study result of case #1's 25 MVA transformer (path #41)

Transformer Thermal Loading Program
Life Cycle Study of Transformer using IEEE Clause 7 Thermal model

Year 2001

	% Loss of Life	Remain Tensile	Remain DP	Max. Hot Spot	Max. Top Oil	Acc. %LOF	Used Life(yrs)
January	0.000	97.05	1400	45.3	31.1	0.000	0.00
February	0.000	97.05	1400	52.4	36.7	0.000	0.00
March	0.000	97.05	1400	55.8	38.2	0.000	0.00
April	0.000	97.05	1400	56.6	39.0	0.001	0.00
May	0.001	97.05	1400	63.0	43.5	0.001	0.00
June	0.002	97.04	1400	75.0	53.8	0.003	0.00
July	0.011	97.03	1399	88.3	63.1	0.014	0.00
August	0.013	97.01	1398	90.3	65.1	0.027	0.00
September	0.002	97.01	1398	74.6	53.3	0.029	0.01
October	0.001	97.00	1398	66.4	46.9	0.030	0.01
November	0.000	97.00	1398	61.1	41.6	0.030	0.01
December	0.000	97.00	1398	53.7	36.1	0.030	0.01

Maximum Loading= 0.814   Used Life= 0.01 years(46 hrs)

Year 2030

	% Loss of Life	Remain Tensile	Remain DP	Max. Hot Spot	Max. Top Oil	Acc. %LOF	Used Life(yrs)
January	0.008	23.95	228	87.1	51.9	88.567	15.17
February	0.027	23.94	228	99.1	60.2	88.594	15.17
March	0.077	23.91	227	108.6	65.1	88.671	15.18
April	0.082	23.88	227	109.4	65.9	88.752	15.20
May	0.282	23.77	226	122.0	73.7	89.035	15.25
June	1.437	23.24	223	139.5	87.1	90.472	15.49
July	12.502	19.07	193	165.8	103.7	102.974	17.63
August	14.647	15.13	164	167.8	105.7	117.621	20.14
September	1.373	14.81	161	139.1	86.7	118.993	20.38
October	0.378	14.72	161	125.4	77.1	119.371	20.44
November	0.221	14.67	160	120.1	71.8	119.592	20.48
December	0.060	14.65	160	106.5	63.0	119.652	20.49

Maximum Loading= 1.435   Used Life= 20.49 years(179478 hrs)

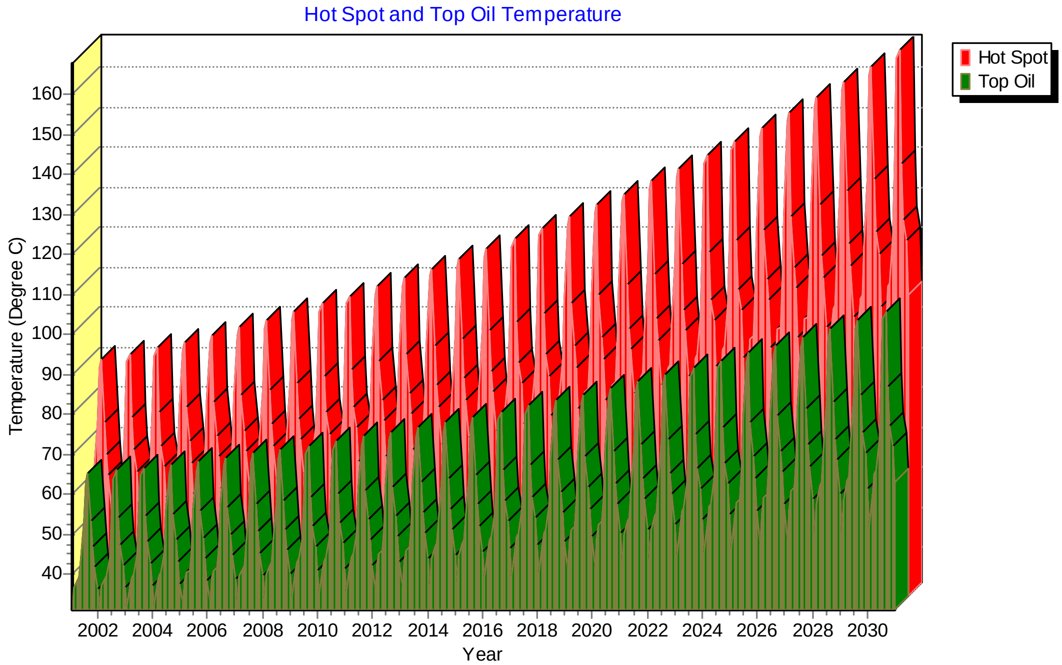

Figure 7.1: Hottest-spot and top-oil temperature of case #1's 25 MVA transformer (Path #41)

7.2.2 Case #2, Transformer Replacement with Moderate Load Growth Rate

The first four years of load growth is constructed using the spreadsheet and the probability tree with the high, expected, and low load growth rate of 2.0, 1.75, and 1.0 %, respectively. The choices compared are: (i) "replace now" or (ii) "delay replacement" at the end of the existing transformer's life. The transformer size ranges from 20-40MVA. Table 7.5 shows the result. The Equivalent Revenue Requirement (ERR) reaches a minimum of $91,327 in the "delay replacement" option with 0.8 pu peak load criteria. In this example, the delay replacement option is economically favorable. The existing transformer is able to be in operation for 9 yrs. before its life ends. The result is shown in Table 7.7. When the transformer's life ends at 10th year, the 30.18MVA unit replaces the existing 18 MVA transformer. The load at that time is 24.1MVA. This corresponds to 0.8 pu peak load criterion (= 24.1/30.18). The "replace now" option is economically more expensive compared to the "delay replacement" option. It can be seen that the maximum hottest-spot and top-oil temp. at 9th year is 150.6°C, 96.5°C respectively, which is too high with a considerable amount of loss-of-life. The "replace now" option gives the minimum ERR of $125,706 for a 28 MVA transformer, compared to the "delay replacement" of $91,327. The utility can save $34,379 per year by choosing to overload the existing transformer.

Table 7.5: Result of case #2 study

```
Transformer Delay Replacement Program


Top-oil rise over ambient at rated load      = 45.0 C
Hottest-spot rise over top oil at rated load = 35.0 C
Oil time constant      = 1.25 hours
Winding time constant = 5.0 minutes
Cooling mode is FA
---------------------------------

Equivalent Revenue Requirement(ERR) for Replace Now Option

 Size    ERR
20.00 $134,345
21.00 $132,260
22.00 $130,365
23.00 $128,753
24.00 $127,327
25.00 $126,051
26.00 $125,852
27.00 $125,737
28.00 $125,706
29.00 $125,762
30.00 $125,909
31.00 $126,150
32.00 $126,493
33.00 $126,945
34.00 $127,513
35.00 $128,205
36.00 $129,031
37.00 $129,999
38.00 $131,119
39.00 $132,402
40.00 $133,858

Equivalent Revenue Requirement(ERR) for Delay Replacement Option

Peak Load    ERR
 0.50      $101,798
 0.60      $93,795
 0.70      $91,569
 0.80      $91,327
 0.90      $91,858
 1.00      $94,336
```

Table 7.6: Detailed result of delay replacement with 0.8 per-unit peak load criterion on load growth path #41, case #2 study

18.00MVA Path No.41

Year	MVA	UIk	Tk	CCk	COLk	CFk	RRk
1	18.00	85000	6800	25925	35888	227	62040
2	18.00	74800	5984	24038	37488	170	61696
3	18.00	64600	5168	22151	39169	113	61433
4	18.00	54400	4352	20264	40937	57	61258
5	18.00	44200	3536	18377	42945	0	61322
6	18.00	34000	2720	16490	45066	0	61556
7	18.00	23800	1904	14603	47307	0	61910
8	18.00	13600	1088	12716	49674	0	62390
9	18.00	3400	272	10829	52176	0	29005
10	30.18	463233	37059	99595	40242	0	139837
11	30.18	449336	35947	97024	41882	2162	141068
12	30.18	435439	34835	94453	43606	2085	140144
13	30.18	421542	33723	91882	45419	2007	139308
14	30.18	407645	32612	89311	47326	1930	138567
15	30.18	393748	31500	86740	49331	1853	137925
16	30.18	379851	30388	84169	51442	1776	137387
17	30.18	365954	29276	81598	53664	1699	136961
18	30.18	352057	28165	79027	56003	1621	136652
19	30.18	338160	27053	76457	58467	1544	136468
20	30.18	324263	25941	73886	61062	1467	136414
21	30.18	310366	24829	71315	63796	1390	136500
22	30.18	296469	23718	68744	66678	1312	136734
23	30.18	282572	22606	66173	69715	1235	137123
24	30.18	268675	21494	63602	72918	1158	137677
25	30.18	254778	20382	61031	76295	1081	138406
26	30.18	240881	19270	58460	79857	1004	139320
27	30.18	226984	18159	55889	83615	926	140430
28	30.18	213087	17047	53318	87580	849	141748
29	30.18	199190	15935	50747	91766	772	143285
30	30.18	185293	14823	48176	96183	695	145054

Levelized Revenue Requirement = $91,772

7.3 Summary

Simulation results for two case studies are presented here. Case studies: #1 relate to the problem of sizing a new transformer, whereas, #2 deals with the problem of an existing system and to evaluate the “delay replacement” option of an existing 18 MVA power transformer. .Both cases #1 and #2 assume moderate (1.75%) load growth.

Load growth rate is a very important factor that needs to be considered in transformer sizing. The analyses and results yield that the most economical transformer’s sizes for Case #1 (moderate load growth) is 25MVA.

In Case #2 (moderate load growth), the rating of the existing transformer is assumed to be 18 MVA with 0.25 pu remaining life. The system is experiencing overload and utility engineers are trying to look into both “replace now” or “delay replacement” option. In both cases, the most economical choice goes to “delay replacement” option. In Case #2, the delay replacement option yields the lower ERR of $91,327 when the new transformer with the initial loading at 0.8 per-unit is selected. The replace now option gives the much higher ERR of $125,796 for a new 28 MVA transformer. The existing transformer can be allowed to overload for the next 9 years until it needs replacement. The “delay replacement” clearly saves utility $34,379 annually.

These case studies utilize typical load profiles, ambient temperature, economic and financial data. However, the optimization techniques presented in this report can be applied to any real situations.

Table 7.7: Life cycle study result case #2’s existing 18 MVA transformer (path #41)

```
Program Transformer Overloading Version 1.0
Life Cycle Study of Transformer using IEEE Clause 7 Thermal model

Year 2001

          % Loss   Remain    Remain   Max.     Max.     Acc.     Used
         of Life  Tensile     DP   Hot Spot  Top Oil    %LOF   Life(yrs)
January    0.001    29.67     266      64.4     40.4   75.001     12.84
February   0.002    29.67     266      73.8     47.2   75.002     12.84
March      0.004    29.67     266      80.0     50.3   75.006     12.84
April      0.004    29.67     266      80.8     51.1   75.010     12.84
May        0.011    29.66     266      90.1     57.1   75.021     12.85
June       0.056    29.64     265     104.6     68.8   75.077     12.86
July       0.374    29.46     264     123.9     81.5   75.450     12.92
August     0.453    29.25     263     125.9     83.5   75.903     13.00
September  0.053    29.23     263     104.2     68.4   75.955     13.01
October    0.016    29.22     263      93.5     60.4   75.971     13.01
November   0.009    29.22     263      88.2     55.2   75.980     13.01
December   0.003    29.22     263      77.9     48.2   75.983     13.01

Maximum Loading= 1.131   Used Life= 13.01 years(113974 hrs)
----------------------------------------------------------------------
Year 2009

          % Loss   Remain    Remain    Max.     Max.     Acc.     Used
         of Life  Tensile     DP     Hot Spot  Top Oil    %LOF   Life(yrs)
January    0.003    20.90     206      77.7     47.1   97.186     16.64
February   0.009    20.90     206      88.6     54.7   97.194     16.64
March      0.023    20.89     206      96.8     58.9   97.217     16.65
April      0.024    20.88     206      97.6     59.7   97.241     16.65
May        0.080    20.85     206     108.8     66.8   97.321     16.66
June       0.400    20.72     205     125.1     79.5   97.721     16.73
July       3.182    19.71     198     148.6     94.5  100.903     17.28
August     3.776    18.57     190     150.6     96.5  104.679     17.92
September  0.381    18.45     189     124.7     79.1  105.060     17.99
October    0.108    18.42     189     112.2     70.2  105.168     18.01
November   0.061    18.40     188     106.9     64.9  105.229     18.02
December   0.018    18.40     188      94.7     56.8  105.247     18.02

Maximum Loading= 1.315   Used Life= 18.02 years(157870 hrs)
      ----------------------------------------------------------------------
```

8. Conclusions

The research is aimed primarily to deal with two major issues, routinely encountered by utility planning engineers, however, without any clear answer:

(i) Economically optimize transformer sizing in a new project with load growth uncertainties, and

(ii) The most cost-effective transformer replacement strategy in an existing system.

Even though the optimization technique developed here is independent of the type of transformer (size, cooling, design, applications, etc.), the numerical examples demonstrate the principles are limited to oil-cooled power transformers, ranges typically between 10-100MVA. This method could easily be expanded to other types of transformers and varied applications.

To address the first issue, an improved optimization method has been proposed over the conventional "loss evaluation" ("Total Owning Cost") method. Besides, the economic considerations traditionally adopted (use of "A" and "B" factors), the proposed method also includes the transformer thermal model, its loss-of-life evaluation subjected to cyclic load and the ambient temperature profile. To take into account the uncertainties in future load growth projection probability tree method is introduced. The economic evaluation utilizes the "Minimum Revenue Requirement" method, which is appropriate for investor-owned utilities (IOUs).

The second problem also utilizes the same tools developed in this research, namely, the thermal model, the economic model and the probabilistic approach to load growth.

Regarding the thermal model, overloading and remaining life expectancy estimation of a transformer, IEEE [1] and IEC [2] standards provide guidelines. These standards require a thorough understanding of the transformer design and heat-transfer equations. IEEE Clause 7 (and the IEC standard) is simple, however, has some limitations.

In order to facilitate the use of these standards by practicing engineers and to avoid long and complex calculations, as an integral part of this research, an interactive computer program has been developed. Based on the research performed, the following conclusions are derived:

1) The IEEE classical model (Clause 7) is simple, easy to follow and requires minimum information. However, it has a number of limitations. It also requires less computation time. On the other hand, IEEE Annex G model is more complex, requires additional information from the manufacturer. This model requires small time step because it employs finite element forward marching technique and hence, is computationally demanding. A direct comparison of the two IEEE models reveals very close agreement for the hottest-spot temperature at steady-state and reasonable overloading conditions. It is only at heavy overload and FOA type cooling, that the results are different. The IEC model is similar to the IEEE classical model and is relatively simple. The major difference is the rated temperature rise and forced cooling type calculation.

2) The deterioration of insulation follows the "Reaction Rate Theory". The hottest-spot temperature and the exposed time reduce the mechanical tensile strength and the degree of poly-

merization of insulation. The normal insulation life of 158,000 hours, corresponding to the "Retained Tensile Strength" of 20% and the "Degree of Polymerization" of 200, is utilized in this research as the one "per-unit" life for power distribution transformer. There exists a good correlation between the RTS and the corresponding DP.

3) The thermal behaviors of the transformer are studied independent of any economic evaluation. Because of the nature of this application, very little effort has been made to combine the thermal model and the economics together with other uncertainties, namely, load growth, transformer failure, and the variation of the ambient temperature and the load cycle. This research has successfully combined a number of these variables into one optimization technique.

4) The proposed optimization technique has been tested for two real commonly faced applications by the planning engineers: (i) buy a new transformer, and (ii) optimize the transformer utilization in a retrofit design. The results obtained from the simulations are quite satisfactory.

5) As a part of this research, a software has been developed and tested. This could be very easily used by the planning engineers as a "design tool." However, more work is needed and other cases must be tested.

6) The results from the proposed optimization technique should also be verified from the field data, when possible.

8.1 Contributions of this Research:

Major contributions of this research can be outlined as follows:

- Study in depth the three thermal models (two IEEE models and the IEC model). A simplified guideline for transformer overloading has also been added in the Appendix A.

- Following the concepts of Per-Unit Life, Relative Aging factor, Equivalent Aging, and end-of-insulation-life criteria, two simple equations have been developed from some experimental data available in the published literature to estimate the transformer remaining life.

- A Windows based, object oriented program has been developed to calculate the hottest-spot temperature, the top- and the bottom-oil temperature for each model. The program also calculates the loss-of-insulation-life, the remaining life, and energy losses following the methodology developed in this research.

- A method of optimal transformer sizing (New Design) and economic replacement alternatives (Retrofit Applications) are presented. It employs the minimum revenue requirement evaluation technique, and calculation of transformer end-of-life based on the thermal model, and the probability of future load growth rate.

- In order to undertake the future uncertainties, the load growth probability- tree structure is employed. The uncertainties of load and ambient temperature are also studied using Monte Carlo simulation.

- The program enumerates the revenue requirement for each transformer size. The minimum value of revenue requirement is the most economical alternative. Examples of different case studies are also presented in this research.

8.2 Future Work:

- The program is slow in optimization studies. Faster programming technique needs to be employed to include uncertain future load growth.

- In order to simplify, the present work assumes "Straight Line" method of depreciation of the transformer. Other depreciation method shall be explored. A survey of depreciation method currently adopted by the utilities would be very useful.

- The calculation of loss-of-insulation-life is based on calculating its mechanical properties (RTS and DP) after aging at constant high temperature. The mathematical modeling is based on very limited test data. The model should be updated when more real data is available.

- The business climate is changing the way utilities are operating. The financial model with profit-oriented objective should be further reviewed. Alternate economic models may also be implemented.

- "Loss Ratio (R)" used in the research is obtained from various transformer design. The electrical efficiency of the transformer varies by this loss ratio and the daily load curve. Sensitivity analysis should be performed for transformer buyer to minimize transformer losses.

- Further validation of the optimization techniques from the real data collected from the industry is recommended.

- Theory and techniques for other transformer applications (Dry-Type, Large Power Transformers, and Smaller Oil-Cooled Distribution Transformers) should be developed.

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Appendix A: Simplified Transformer Overloading Guidelines

Loading power transformers beyond the nameplate rating is commonly practiced by most utilities. A simplified and general transformer overloading guidelines described below is also depicted in Figure A.1 and summarized in Table A.1 for further clarity and clear understanding.

- **Understand Transformer Nameplate Rating and Design Fundamentals** - Transformer Classification (Distribution and Power); Cooling; Average Winding Temperature Rise; Insulation Type (thermally upgraded vs. *kraft* paper) and Class; Allowable Hottest-Spot Temperature and Design Limits, Insulation Life vs. Transformer Life; etc.

- **Determine End-of-Insulation Life Criteria and the Normal Insulation Life Value** - RTS and DP or other. Typical industry standard for transformer life is between 20 to 40 yrs. 30 yrs., is the most commonly used number.

- **Moisture Content -** Doubling of moisture content reduces insulation life by half.

- **Determine the Ambient Temperature** - Worst possible condition over 24 hrs. period and estimate suitable correction. For every 1°C ambient temperature decrement, loading capacity can be increase by 1% without any loss-of-life or vice versa.

- **Normal Life Expectancy Loading** - Average (24 hrs.) maximum hottest-spot temperature of 110°C without exceeding the maximum value of 120°C with no additional loss-of-life. Normal life is the transformer's life when it operates at a constant hottest-spot temperature of 110°C. No limit for loading beyond nameplate rating as long as the hottest-spot temperatures do not exceed 110°C.

- **Planned Loading beyond the Nameplate Rating** - Average (24 hrs.) maximum temperature of 110°C without exceeding the maximum value of 130°C with limited loss-of-life. Aging rate is double for every 6-8°C hottest-spot temperature increment.

- **Long-Time Emergency Loading** - It is recommended that the maximum hottest-spot temperature should not exceed 140°C, otherwise substantial loss-of-life is expected.

- **Short-Time Overloading** - Usually last for a short-time (less than half-an hour), and the hottest-spot temperature may go up to 180°C with severe loss-of-life. Transformer failure is expected due to the bubble and gas formation in the oil.

- **Maximum Overloading at any time -** Limits to 2 times the highest rating.

- **Maximum Allowable Absolute Temperature -** 180°C (IEEE) and 160°C (IEC).

- **Bushing Overloading Capacities -** 150°C maximum bushing hottest-spot temperature and/or 2 times rated bushing current as per IEEE.

- **Bushing-type Current Transformer -** Bushing-type current transformers have the top-oil as their ambient, which is limited to 105°C.

- **Recommended Practice** - For normal operation, for the winding hottest-spot temperature, in case of OA/FA or OA/FA/FA set the alarm between 115-120°C and trip between 125°C and 130°C. For FOA cooling, it is recommended that both alarm and trip should be set at lower values by 5-10°C. At higher operating temperatures, expect significant loss-of-insulation-life depending on the duration, frequency, and the moisture content.

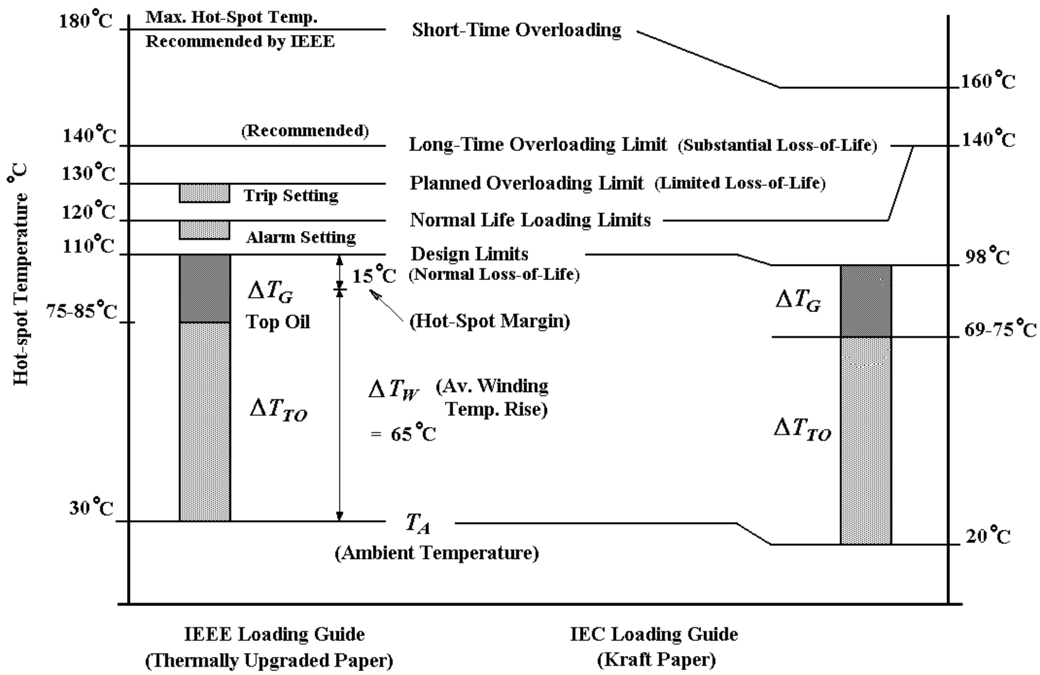


Figure A.1: The thermal and electrical limits for various types of loading

Table A.1: Thermal and electrical limits for various types of loading

Type of Loading	IEEE			IEC		
	Current (pu)	Winding Hot-spot	Top-oil Temp.	Current (pu)	Winding Hot-spot	Top-oil Temp.
Normal Life Expectancy Loading	2	120	105	1.5	140	105
Planned Loading beyond the Nameplate Rating	2	130	110	-	-	-
Long-Time Emergency Loading	2	140	110	1.5	140	115
Short-Time Emergency Loading	2	180	110	1.8	160	115

In case of unavailable winding hottest-spot temperature values, recommended values for the top-oil temp. gauge settings (OA/FA, OA/FA/FA) are 100°C for alarm and 110°C for trip. For FOA, the alarm and trip settings are lowered by 5-10°C and consult with the manufacturer.

In order to evaluate the transformer overloading capacity and the possible loss-of-life, the following factors should be considered:

- Nameplate Rating
- Cooling Class, Cooling Design and Design Margin
- Operating Conditions - Altitude, Ambient Temperature and Seasonal Adjustment
- Loading Cycle with respect to the Maximum Rating – Initial Load, Equivalent Continuous Load and Overloading Requirements
- Planned Loading beyond Nameplate Rating
- Long-Term Emergency Loading
- Short-Term Emergency Loading
- Loss-of-Life Expectancy
- Other Limitations than Hottest-spot Temperature (CT, Bushings, etc.)
- Cooling Upgrade
- Operational and Routine Maintenance Practice
- Historical Loading Data

Appendix B: Delphi 4.0 (Pascal for Windows) Program's Screen Shots

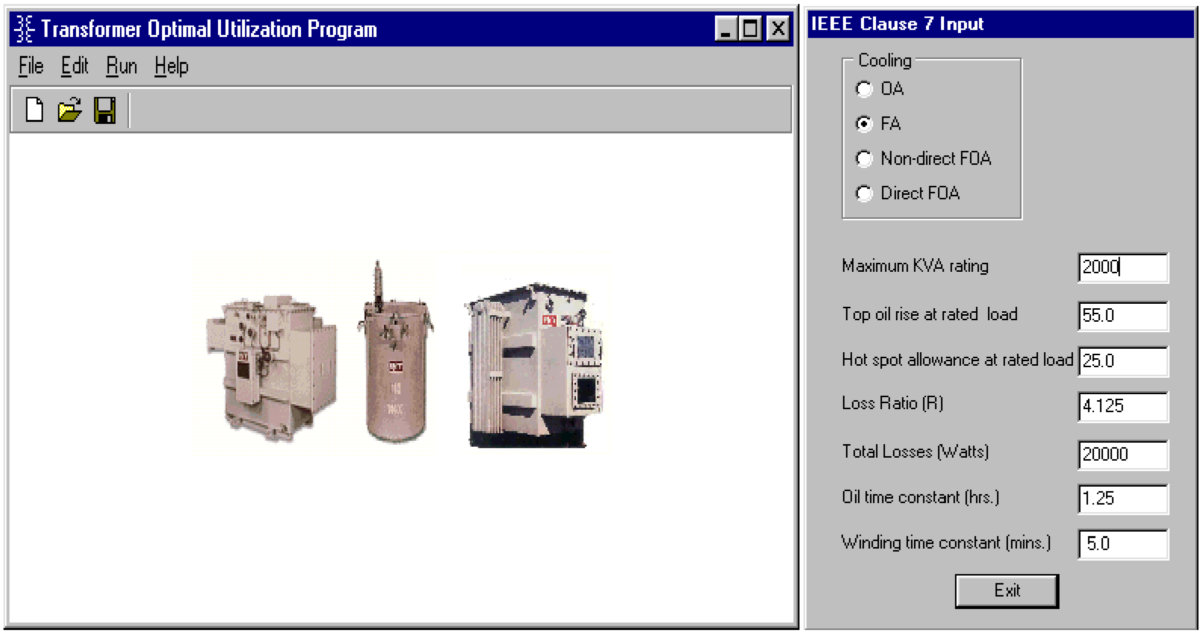


Figure B.1: Transformer Type and Cooling

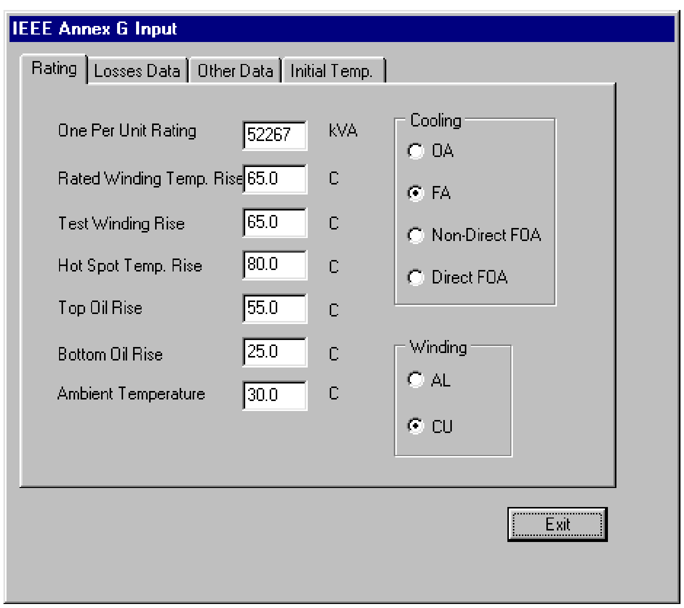


Figure B.2: IEEE Annex G Input Data File

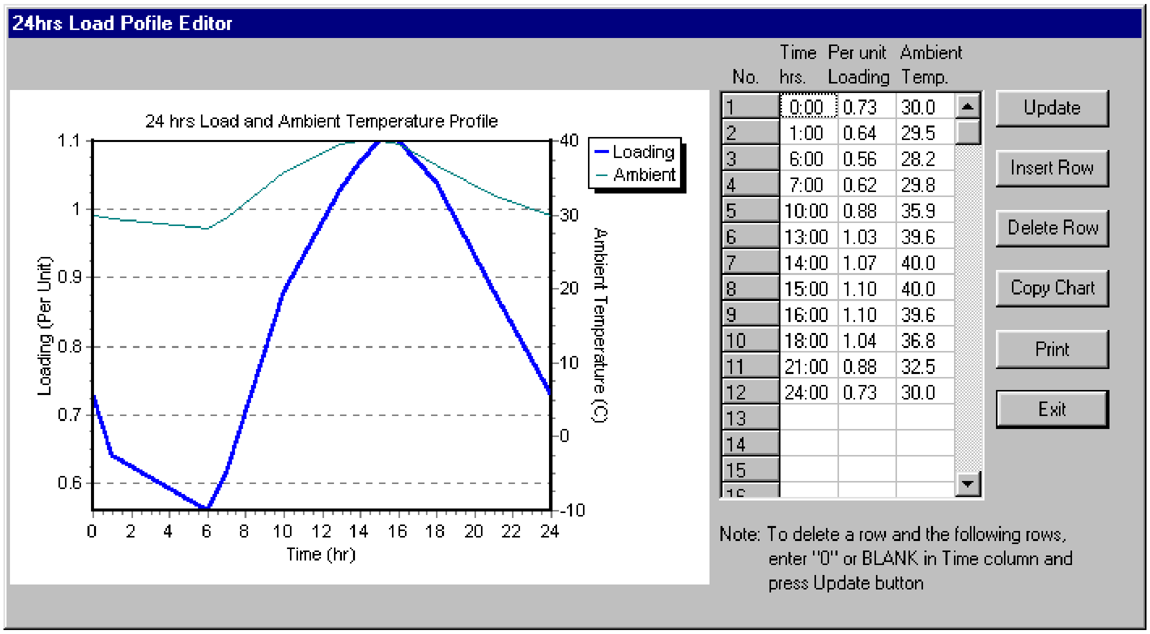


Figure B.3: Daily Load and Temperature Profile

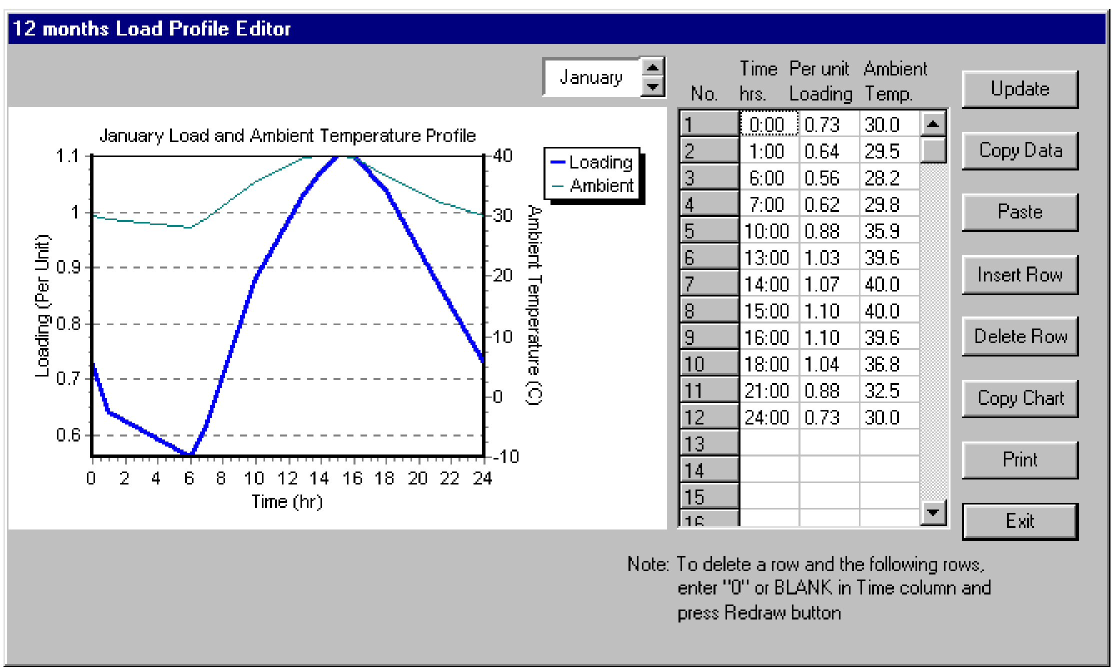


Figure B.4: Monthly Load and Temperature Profile

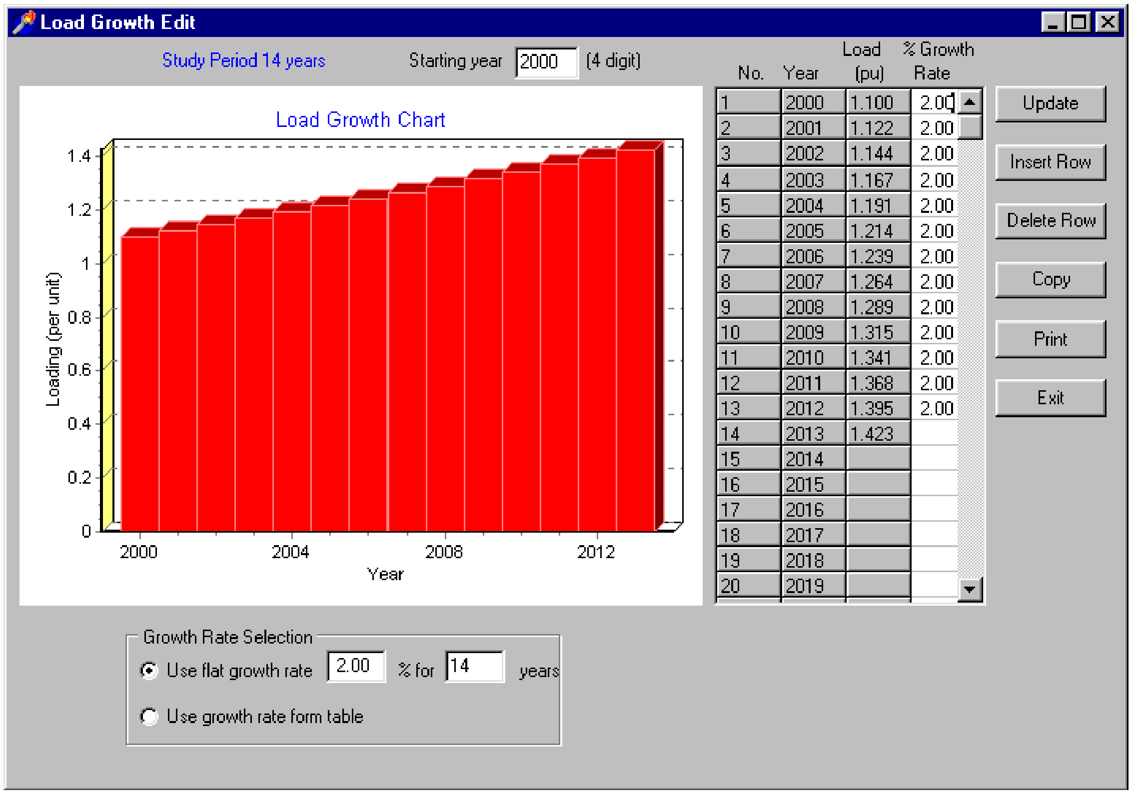
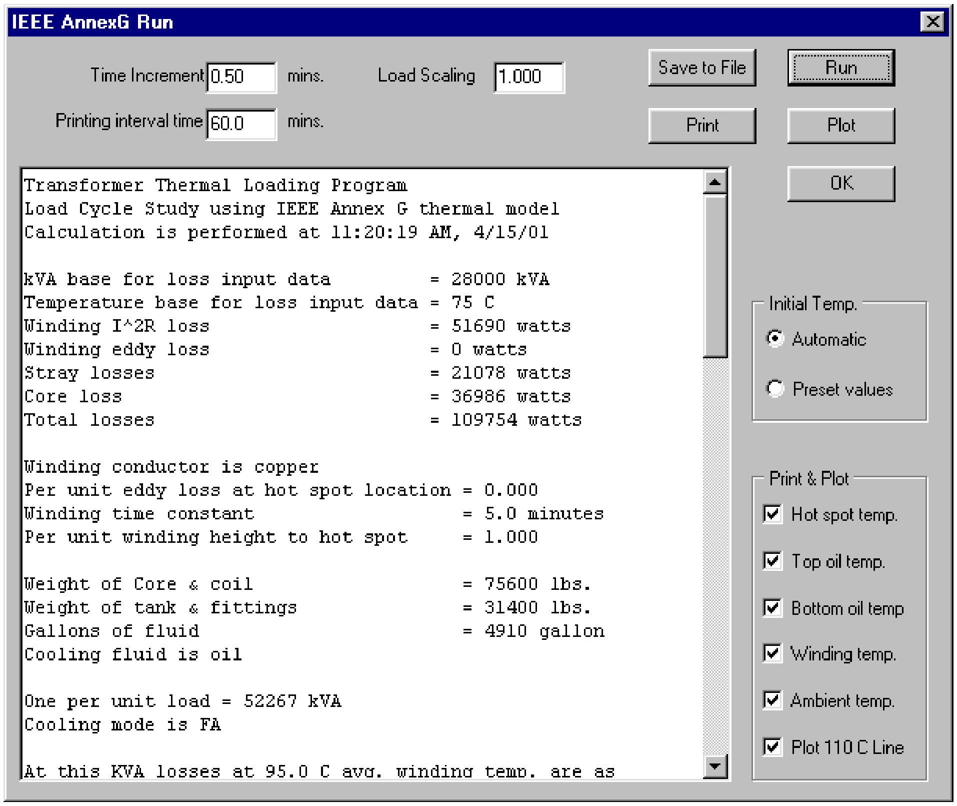


Figure B.5: Annual Load Growth Data



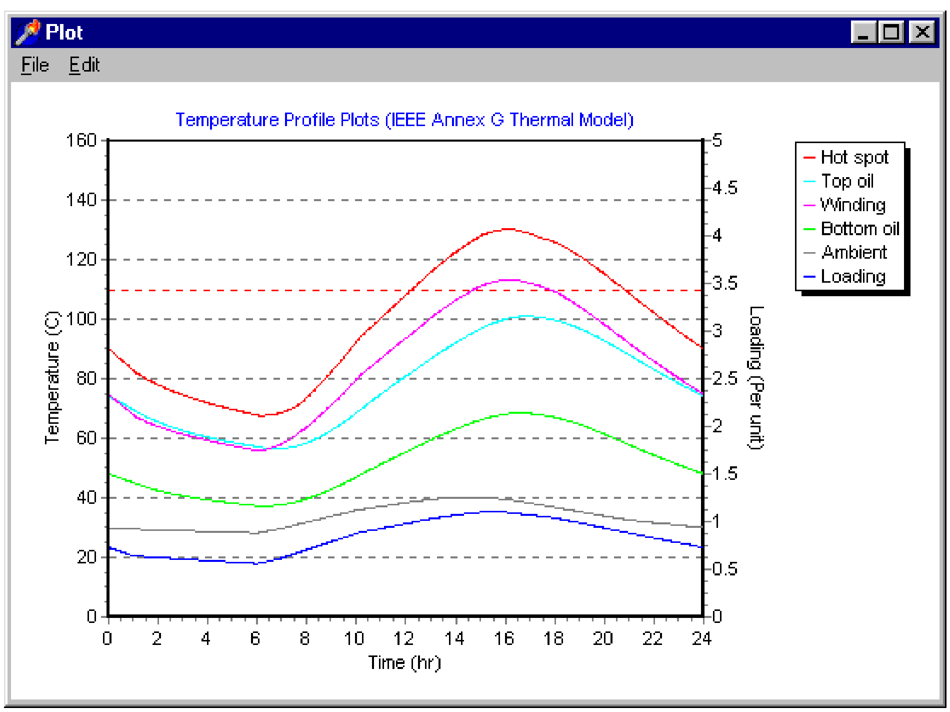
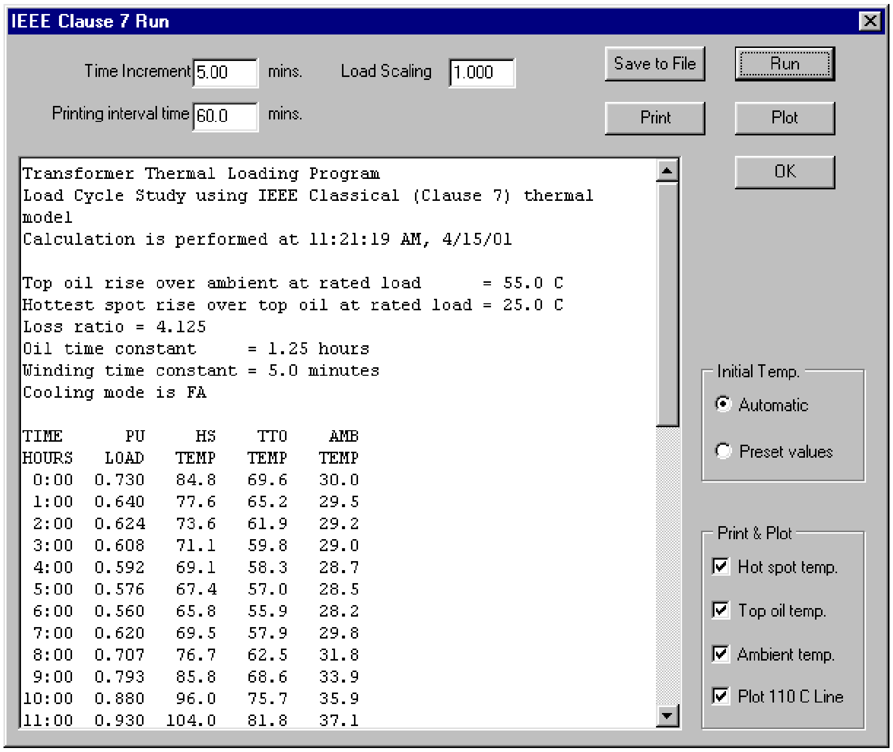


Figure B.6 (a) (b): IEEE Annex G Run Data and Plot



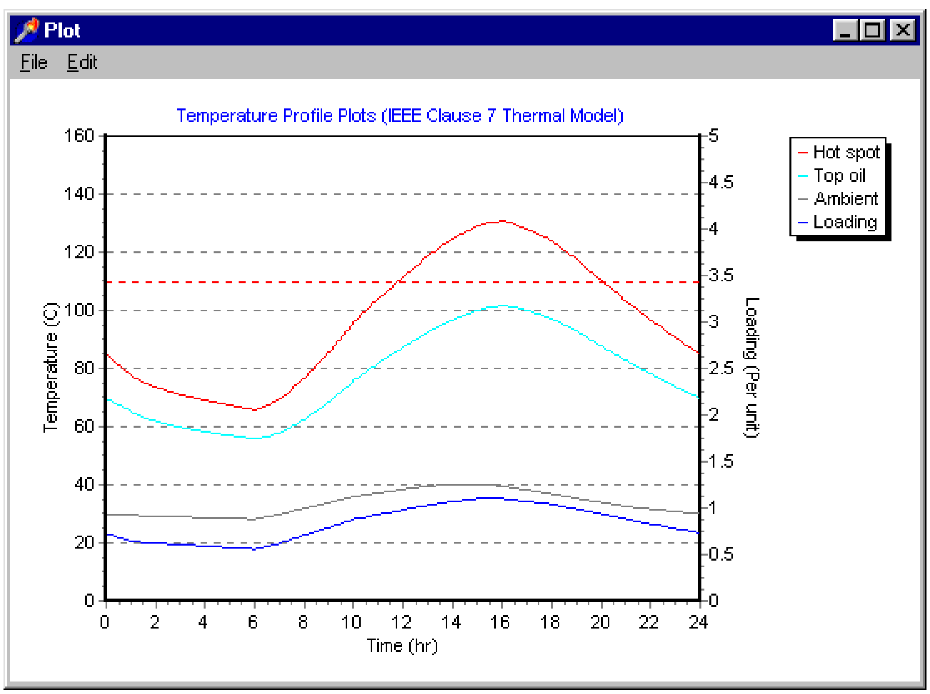
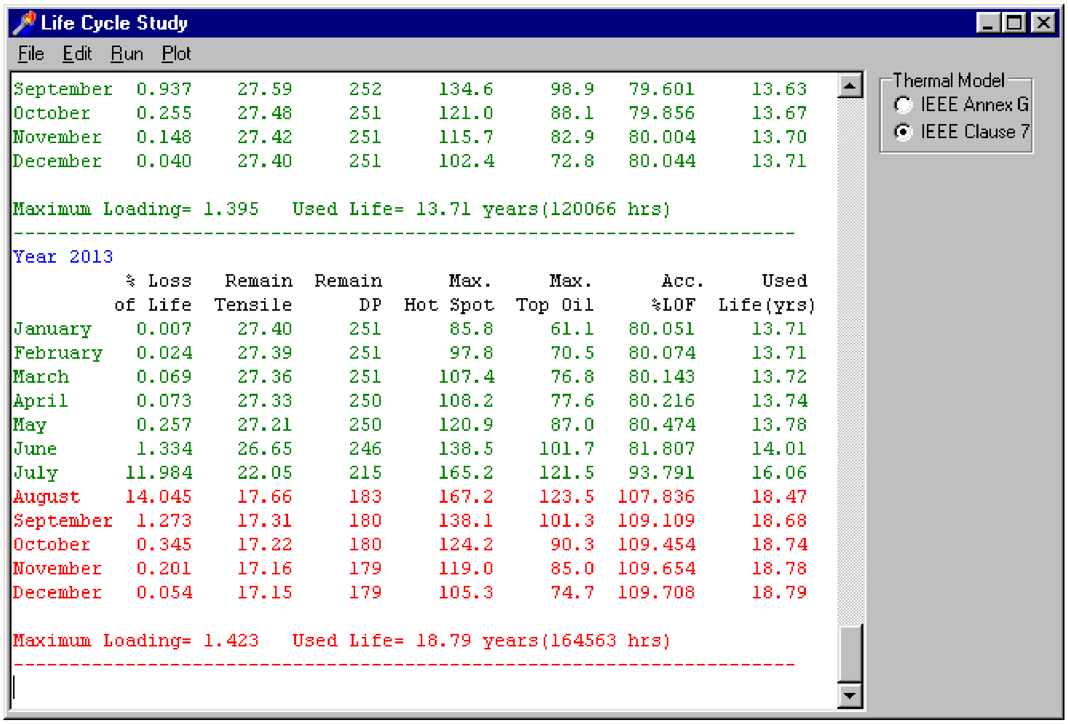


Figure B.7 (a) (b): IEEE Clause 7 Run Data and Profile



Life Cycle Study

File Edit Run Plot

September	0.937	27.59	252	134.6	98.9	79.601	13.63
October	0.255	27.48	251	121.0	88.1	79.856	13.67
November	0.148	27.42	251	115.7	82.9	80.004	13.70
December	0.040	27.40	251	102.4	72.8	80.044	13.71

Maximum Loading= 1.395 Used Life= 13.71 years(120066 hrs)

Year 2013

	% Loss of Life	Remain Tensile	Remain DP	Max. Hot Spot	Max. Top Oil	Acc. %LOF	Used Life(yrs)
January	0.007	27.40	251	85.8	61.1	80.051	13.71
February	0.024	27.39	251	97.8	70.5	80.074	13.71
March	0.069	27.36	251	107.4	76.8	80.143	13.72
April	0.073	27.33	250	108.2	77.6	80.216	13.74
May	0.257	27.21	250	120.9	87.0	80.474	13.78
June	1.334	26.65	246	138.5	101.7	81.807	14.01
July	11.984	22.05	215	165.2	121.5	93.791	16.06
August	14.045	17.66	183	167.2	123.5	107.836	18.47
September	1.273	17.31	180	138.1	101.3	109.109	18.68
October	0.345	17.22	180	124.2	90.3	109.454	18.74
November	0.201	17.16	179	119.0	85.0	109.654	18.78
December	0.054	17.15	179	105.3	74.7	109.708	18.79

Maximum Loading= 1.423 Used Life= 18.79 years(164563 hrs)

Figure B.8: Life Cycle Analysis Calculated Data

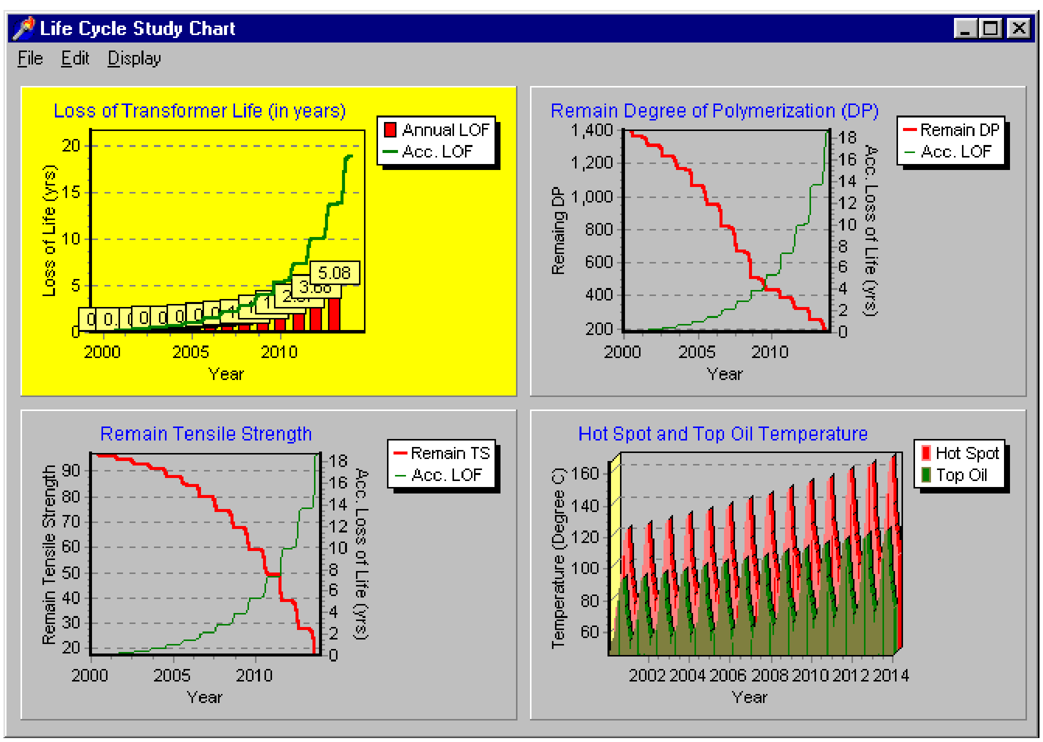


Figure B.9: Life Cycle Study: Composite Chart

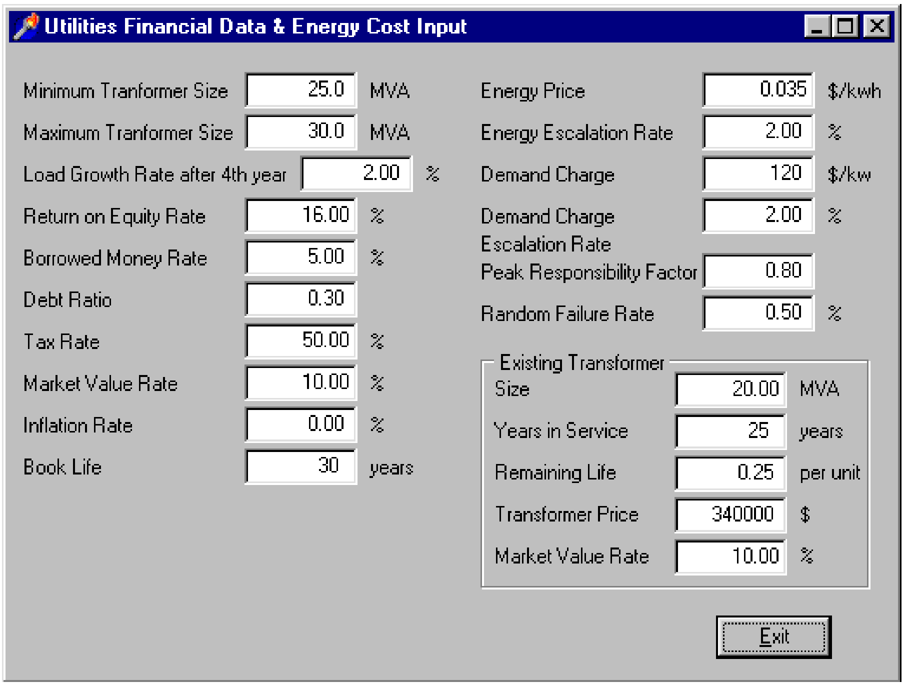


Figure B.10: Utility Financial Data and Energy Cost Input Data

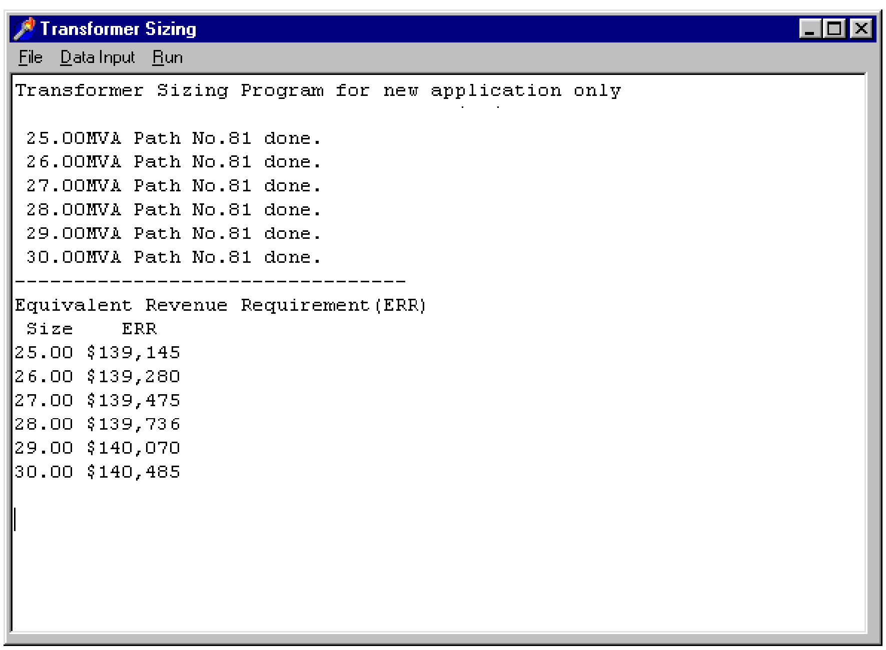


Figure B.11: Optimum Transformer Sizing Output Data for New Procurement

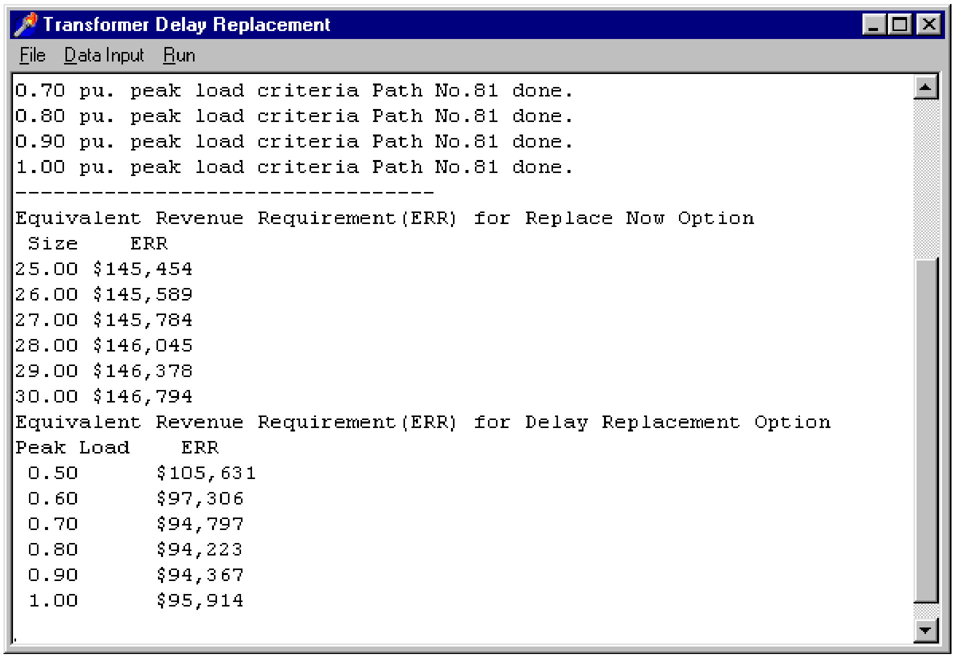


Figure B.12: Transformer Replacement Strategy Data

Appendix C: Comparison Between IEEE Loading Guide C57.91-1995 and IEC Loading Guide IEC 354-1991

No.	Item compared	IEEE C57.91-1995	IEC 354-1991	Comments
1	Distribution Transformer Size	≤ 500 kVA	≤ 2,500 kVA, 3-phase ≤ 833 kVA, single phase	
2	Power Transformer Size	≤ 100 MVA	Medium ≤ 100 MVA, 3-phase ≤ 33.3 MVA, single phase Large > 100 MVA, 3-phase > 33.3 MVA, single phase	For IEEE's power transformer in excess of 100MVA overloading, refer to IEEE C57.115-1991
3	Average ambient temp.	24 hr. average: 30°C (40°C Max for air cooled)	20°C (40°C Max.)	
4	Average winding temp. rise at rated load ΔT_{WR}	65°C (thermally upgraded paper) 55°C (Kraft paper)	65°C (ONAN distribution transformer) 63°C (ON.. power transformer) 63°C (OF.. power transformer) 68°C (OD.. power transformer)	Rated average winding rises in IEC vary by cooling type. Rated average winding temp. rise given here is maximum design value.
5	Top oil temp. rise at rated load ΔT_{TOR}	55°C (45°C) for OA 50°C (40°C) for FA, ≤ 133% 45°C (37°C) for FA, > 133% 45°C (37°C) for FOA both direct and non-direct flow Note: the temperature in parenthesis is for 55°C average winding rise.	55°C (ONAN distribution transformer) 52°C (ON.. power transformer) 56°C (OF.. power transformer) 49°C (OD.. power transformer)	Rated top oil temp. rises given here are typical values.

COMPARISON BETWEEN IEEE LOADING GUIDE C57.91-1995 AND IEC LOADING GUIDE IEC 354-1991 (Contd.)

6	Hot spot allowance (over top oil rise at rated load) ΔT_{GR}	The standard preferably recommends using imbedded detector for measuring hot spot allowance. However, *second alternative* is given by calculation as: $\Delta T_{GR} = \Delta T_{WR} - \Delta T_{TOR} + 15(10)$ ΔT_{GR} is calculated from avg. winding rise over top oil plus 15(10) corresponding to 65°C and 55°C winding rise respectively. The *third alternative* is to assume that rated hot spot rise is 80°C and 65°C for 65°C and 55°C average winding rise respectively. Therefore, rated hot spot allowance can be found by subtracting rated top oil rise by rated hot spot rise. The results are as follows: 25°C (20°C) for OA 30°C (25°C) for FA, ≤ 133% 35°C (28°C) for FA, > 133% 35°C (28°C) for FOA both direct and non-direct flow	Using of direct measurement is recommended for higher accuracy. However, the simplified calculation is given as: $\Delta T_{GR} = (\Delta T_{WR} - \Delta T_{AVGOR})H$ ΔT_{GR} is calculated from avg. winding rise over avg. oil multiplied by H factor. H factor varies from 1.1 to 1.5 depending on transformer size and design. 23°C (ONAN distribution transformer) 26°C (ON.. power transformer) 22°C (OF.. power transformer) 29°C (OD.. power transformer)	See IEC thermal diagram from Figure 3.4.
7	Rated hot spot temp. rise	65°C (55°C winding rise) 80°C (65°C winding rise)	78°C	Rated hot spot temp. rise given here is maximum design value.
8	Hot spot temp. rise ΔT_{HS}	$\Delta T_{HS} = \Delta T_{TO} + \Delta T_G$	$\Delta T_{HS} = \Delta T_{TO} + \Delta T_G$	

COMPARISON BETWEEN IEEE LOADING GUIDE C57.91-1995 AND IEC LOADING GUIDE IEC 354-1991 (Contd.)

9	Rated hot spot temperature	95°C (55°C winding rise) 110°C (65°C winding rise)	98°C 110°C (when thermally upgraded paper is used.)	As IEC 76-2 does not consider thermally upgraded insulation for oil-immersed transformer, temperature rise limits and improvement in thermal behavior may be taken into account by agreement between the manufacturer and user. A normal life expectancy at hot spot temperature of 110°C is used. Rated hot spot temperature given here is maximum design value.
10	Top oil temp. rise ΔT_{TO}	$\Delta T_{TO} = \Delta T_{TOR}\left(\frac{K^2R+1}{R+1}\right)^n$ Same equation is applied for all cooling type. n = 0.8 for OA = 0.9 for FA = 1.0 for FOA	ON.. cooling $\Delta T_{TO} = \Delta T_{TOR}\left(\frac{K^2R+1}{R+1}\right)^n$ n = 0.8 for ONAN distr. transformer = 0.9 for ON. power transformer OF.. & OD.. cooling Top oil rise is calculated from bottom oil & avg. oil rise. $\Delta T_{TO} = \Delta T_{BOR}\left(\frac{K^2R+1}{R+1}\right)^n +$ $2(\Delta T_{AVGOR} - \Delta T_{BOR})K^{2m}$ n = 1.0 m = 0.8 for OF.. = 1.0 for OD.. $2(\Delta T_{AVGOR} - \Delta T_{BOR})$ is a calculated value of top oil rise over bottom oil.	The oil exponential, *n*, of IEEE and IEC loading guide is the same for all cooling types.

COMPARISON BETWEEN IEEE LOADING GUIDE C57.91-1995 AND IEC LOADING GUIDE IEC 354-1991 (Contd.)

11	Hot spot allowance ΔT_G	$\Delta T_G = \Delta T_{GR} K^{2m}$ m = 0.8 for OA, FA, NDFOA = 1.0 for DFOA	$\Delta T_G = \Delta T_{GR} K^{2m}$ m = 0.8 for ONAN, ON.. & OF.. = 1.0 for OD..	The winding exponential, *m*, of IEEE and IEC loading guide is the same for all cooling types.
12	Top oil temp. rise ΔT_{TO}	Top oil temp. rise follows exponential equation. $\Delta T_{TO} = \Delta T_{TO,i} + (\Delta T_{TO,u} - \Delta T_{TO,i})(1 - e^{-t/\tau o})$ where τ_o is oil time constant (≈ 3 hrs.)	Top oil rise in ON.. cooling and bottom oil rise in OF..&OD.. cooling also follow exponential equation. $\Delta T_{TO} = \Delta T_{TO,i} + (\Delta T_{TO,u} - \Delta T_{TO,i})(1 - e^{-t/\tau o})$ $\Delta T_{BO} = \Delta T_{BO,i} + (\Delta T_{BO,u} - \Delta T_{BO,i})(1 - e^{-t/\tau o})$ The second term of ΔT_{TO} for OF.. and OD.. cooling, $2(\Delta T_{AVGOR} - \Delta T_{BOR})K^{2m}$, follows exponential equation but at faster winding time constant. IEC recommends neglecting this time constant.	IEEE's oil time constant, τ_o, has to be corrected if oil exponential, *n*, is not equal to 1.0, but IEC does not mention this issue.
13	Loss of insulation life	For 110°C rated hot spot Per Unit Life = $9.80 x 10^{-18} e^{\left[\frac{15000}{T_{HS}+273}\right]}$ Relative aging rate (F_{AA}) = $e^{\left[\frac{15000}{383} - \frac{15000}{T_{HS}+273}\right]}$ For 95°C rated hot spot Per Unit Life = $2.00 x 10^{-18} e^{\left[\frac{15000}{T_{HS}+273}\right]}$ Relative aging rate = $e^{\left[\frac{15000}{368} - \frac{15000}{T_{HS}+273}\right]}$ Aging rate is double when hot spot temperature increases about 7-8°C in the hot spot temperature ranges from 110-140°C.	No absolute life is mentioned in the IEC standard but relative aging.. Relative aging rate is double for every fixed 6°C increase in hot spot temperature. Relative aging rate = $2^{(T_{HS}-98)/6}$	IEC doesn't give absolute life. IEEE no longer specifies absolute life, however, still gives various absolute life from different end of life criteria for information only.