Transformer Maintenance Interval Management

Roy Moxley and Armando Guzmán
Schweitzer Engineering Laboratories, Inc.

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Roy Moxley and Armando Guzmán
Schweitzer Engineering Laboratories, Inc.
Pullman, WA USA

ABSTRACT

Recent surveys indicate that the average age of utility power transformers exceeds 30 years. Managing these critical assets requires monitoring the factors that cause transformer damage. Excessive heat and mechanical stress during through faults on transformers are recognized as the two major causes of damage. New technology in transformer protection relays provides for both thermal and through-fault monitoring.

This paper demonstrates how to use the transformer thermal damage and loss-of-life information from IEEE Std. C57.91-1995 to schedule proactive maintenance. It also presents through-fault recording and accumulated data and discusses how these relate to transformer short-circuit standards.

INTRODUCTION

In the historical struggle between ac and dc power transmission, ac is generally preferred because it allows easy conversion of voltages to higher levels for long distance transport. Power transformers are a critical link in the ac path of electricity from the generating stations to end users. In terms of total investment, electric utilities invest at least as much in transformers as they do in generating stations. In many cases, because of the larger installed base, utilities invest more in transformers.

Transformers are expected to last from 20–30 years, and in many cases, even longer. Because regulators and financial markets measure a utility's ability to make efficient use of resources, utilities must maximize asset utilization. Based on transformer design and experience, we know that the amount of service a transformer "sees" is an indicator of serviceability. As they say, "it's not the age—it's the mileage."

Measurable indicators of transformer serviceability include electrical load; top-oil, hottest-spot, and ambient temperatures; fault history; and dissolved gas analysis. Utilities that use these indicators can make intelligent profit/risk decisions and plan optimal transformer loading and maintenance.

MEASUREMENTS

The best way to protect and extend the life of transformers is to collect information such as load and fault current as well as top-oil or hottest-spot temperatures, and receive notification when a value has reached a preset level. Logically combining these quantities can help predict or anticipate an alarm condition, and keeping a record of these measurements provides a more complete picture of the transformer's insulation condition.

The challenge is providing a means to collect this information without creating a massive new system requiring its own maintenance and cost structure. Protective relays that are permanently connected to the transformer current (and possibly temperature inputs) as shown in Figure 1, have memory and recording capability, and have logical decision making capacity, can be the beginning of a comprehensive “life management” system for transformers.

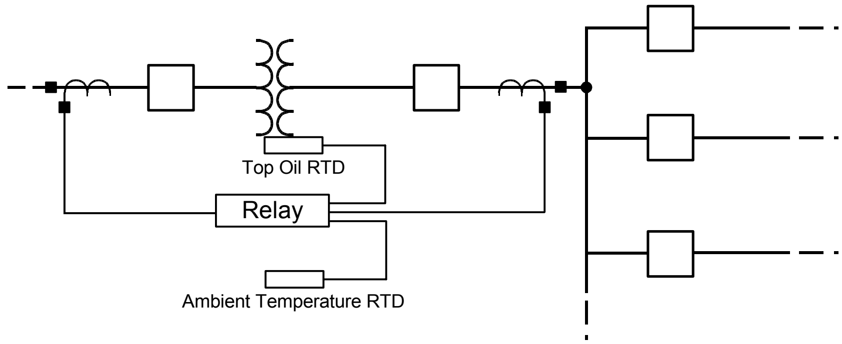

Figure 1 Transformer Relay With Connected RTDs for Thermal Monitoring

Construction and usage standards for transformers provide a starting point for applying these measurements to determine optimal loading at a given ambient temperature and predict when it is appropriate to schedule maintenance prior to a life-ending event.

TEMPERATURE MEASUREMENTS AND CALCULATIONS

IEEE standards and numerous technical papers have established guidelines for loading transformers based on temperature limits for oil and conductors. For example, recognizing that a “loss of life” occurs as temperatures increase, *IEEE Standard C57.115-1991: Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MVA (65ºC Winding Rise)*, Table 2, includes temperature limits for different load conditions. All of the conditions above normal loading involve some degree of an accelerated loss of life of the transformer [1] [2].

The standard shows that from a managed ownership standpoint, regularly overloading a transformer at high ambient temperatures causes accelerated aging. The question is: how should maintenance of the transformer change based on the amount and duration of overloads?

Both operator actions and system events can cause transformer overloads. Therefore, temperatures should be continuously monitored, and accumulated loss of life should be measured and recorded. The most important two values to calculate or measure are hottest-spot temperature and top-oil temperature. IEEE Std. C57.91-1995 provides formulas for performing these calculations. We have programmed these formulas in protective relays to calculate temperatures. The user inputs the transformer constants required (see Appendix A), such as thermal time constants, ratio of no-load to load losses, and total losses at rated output. If these constants are unknown, the standards provide reasonable default values for approximate calculations.

Using the entered constants, the relay provides instantaneous and accumulated loss-of-life and aging acceleration factor alarm points. Calculations are based on what information is available. Temperature devices on the transformers, such as Resistance Temperature Detectors (RTDs), may or may not be available, so different calculations are made depending on this availability [3].

THERMAL CALCULATIONS USING AMBIENT AND TOP-OIL TEMPERATURES

In this case, the relay receives measured ambient and top-oil temperature inputs and uses the top-oil temperature to calculate the hottest-spot temperature.

A single-tank, three-phase transformer can have as many as two thermal inputs: the ambient temperature input and the top-oil temperature input. Independent, single-phase transformers normally have as many as four thermal inputs: an ambient temperature input and a top-oil temperature input for each one of the three tanks. During a fixed time interval, $\Delta t = 1$ minute, the relay calculates the winding hottest-spot temperature at the end of the interval, according to the following expression:

$$\Theta_H = \Theta_{TO} + \Delta\Theta_H$$

where:

Θ_H = winding hottest-spot temperature, °C

Θ_{TO} = top-oil temperature, °C

$\Delta\Theta_H$ = winding hottest-spot rise over top-oil temperature, °C

The relay calculates winding hottest-spot rise over top-oil temperature, $\Delta\Theta_H$, according to the following:

$$\Delta\Theta_H = \left(\Delta\Theta_{H,U} - \Delta\Theta_{H,i}\right) \bullet \left(1 - e^{\frac{-\Delta t}{60 \bullet \tau_W}}\right) + \Delta\Theta_{H,i}$$

where:

$\Delta\Theta_{H,U}$ = the ultimate hottest-spot rise over top-oil temperature for any load, °C

$\Delta\Theta_{H,i}$ = initial hottest-spot rise over top-oil temperature at the start time of the interval, °C

τ_W = winding time constant of hot spot, in hours

Δt = one-minute temperature data acquisition interval

$$\Delta\Theta_{H,U} = \Delta\Theta_{H,R} K^{2m}$$

where:

K = load expressed in per unit of transformer nameplate rating according to the cooling system in service (phase current divided by the nominal current)

m = winding exponent

$\Delta\Theta_{H,R}$ = rated winding hottest-spot rise over top-oil at rated load, °C

The implementation of this equation over time is shown in Figure 2 below.

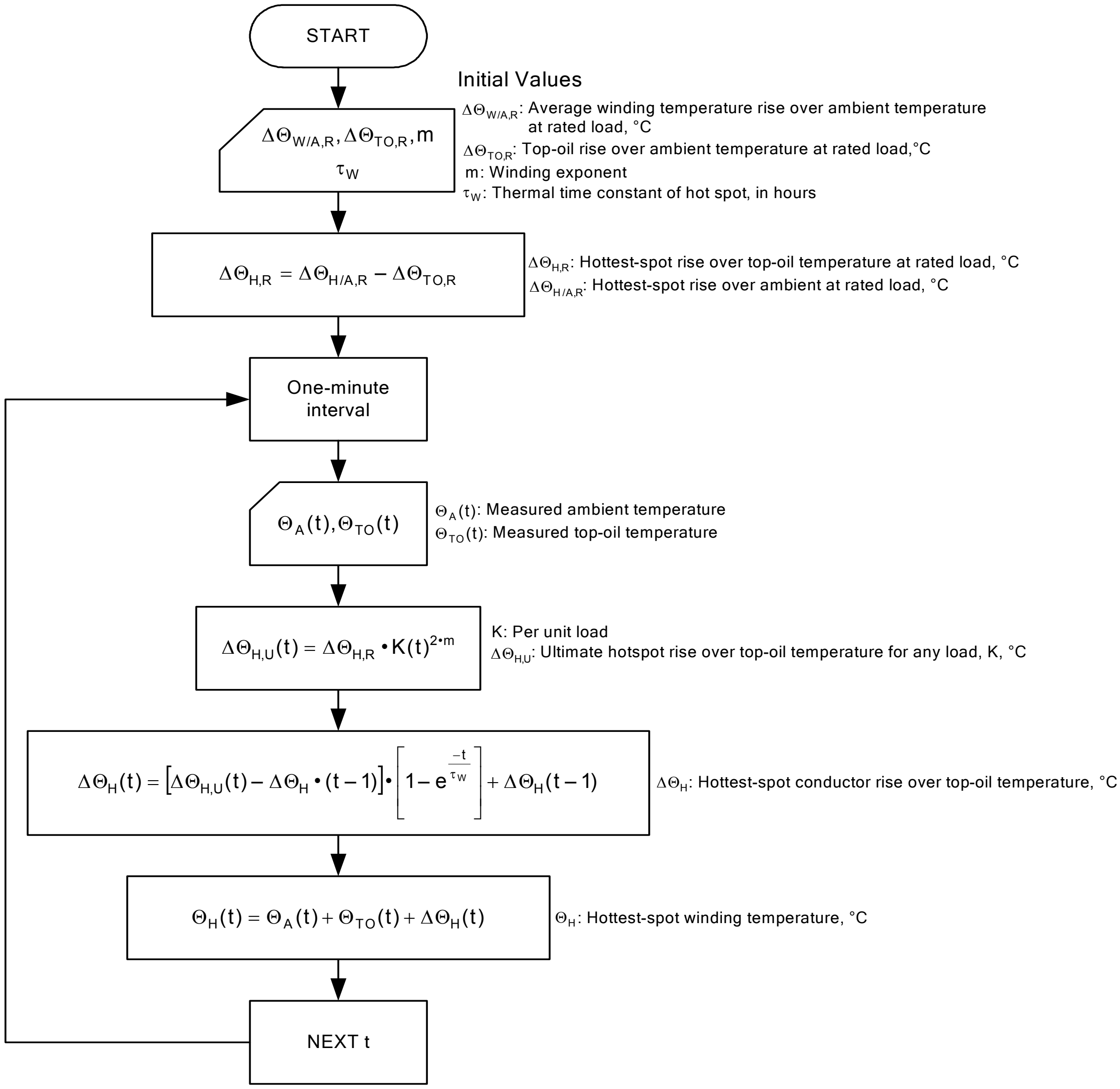

Figure 2 Iterative Real-Time Hottest-Spot Calculation

Thermal Calculations With Only Ambient Temperature Inputs

If only ambient temperature is available, the relay calculates both top-oil temperature and hottest-spot temperature. Typical variances in ambient temperature for the same load could result in a difference in aging of transformer insulation by 100 times, so it is critical that ambient temperature is available.

Where the relay has a measured ambient temperature input without a top-oil temperature input, you have one thermal input (for ambient temperature) regardless of whether you have a single three-phase transformer or independent single-phase transformers. The relay calculates winding hottest-spot temperature, Θ_H, according to the equation in the earlier case:

$$\Theta_H = \Theta_{TO} + \Delta\Theta_H$$

and calculates top-oil temperature, Θ_{TO}, according to the following:

$$\Theta_{TO} = \Theta_A + \Delta\Theta_{TO}$$

where:

Θ_A = ambient temperature, °C

$\Delta\Theta_{TO}$ = top-oil rise over ambient temperature, °C

The relay calculates top-oil rise over ambient temperature according to the following:

$$\Delta\Theta_{TO} = \left(\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i}\right) \bullet \left(1 - e^{\frac{-\Delta t}{60 \bullet \tau_{TO}}}\right) + \Delta\Theta_{TO,i}$$

where:

$\Delta\Theta_{TO,U}$ = the ultimate top-oil rise over ambient temperature for any load, °C, and is a function of load

$\Delta\Theta_{TO,i}$ = initial top-oil rise over ambient temperature at the start time of the interval, °C

τ_{TO} = top-oil time constant of transformer, in hours

The relay calculates the ultimate top-oil rise over ambient temperature, $\Delta\Theta_{TO,U}$, according to the following expression:

$$\Delta\Theta_{TO,U} = \left(\frac{K^2 \bullet R + 1}{R + 1}\right)^n \bullet \Delta\Theta_{TO,R}$$

where:

R = ratio of load loss at rated load to no-load loss

n = oil exponent

$\Delta\Theta_{TO,R}$ = top-oil rise over ambient temperature at rated load, °C

For any n (oil exponent) value and any load value, the relay calculates the thermal top-oil time constant according to the following expression:

$$\tau_{TO} = \tau_{TO,R} \bullet \left(\frac{\dfrac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}} - \dfrac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}}{\left(\dfrac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}} - \left(\dfrac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}}}\right)$$

where:

$\tau_{TO,R}$ = thermal time constant in hours at rated load with initial top-oil temperature equal to ambient temperature

Real-time values include calculated temperatures as well as loss-of-life accumulations. Instantaneous values are useful to operators in making dispatch decisions.

Transformer standards provide guidelines for operating at "damaging" thermal levels. For example, Table 1 from IEEE Std. C57.115-1991 provides what can be considered reasonable loading times for given hottest-spot temperatures [1]. Operators or relays should act to limit the time at higher-than-rated temperatures. Relay contacts or alarms sent via SCADA can also initiate control actions to reduce load.

INSULATION AGING

Hottest-spot temperature above 90–105ºC causes irreversible degradation of the cellulose insulation structure of a transformer [4] [5]. This degradation accumulates over time until the insulation material fails. The mode of the insulation failure in these cases is typically of a mechanical nature, e.g., cracking and flaking caused by the heavy carbonization of the insulation material. This mechanical degradation of the insulation material eventually results in an electrical failure of the device.

Insulation Aging Acceleration Factor

Based on transformer standards, we calculate an insulation aging acceleration factor, F_{AA}, which indicates how fast the transformer insulation is aging.

We calculate the insulation aging acceleration factor, F_{AA}, for each time interval, Δt, as follows:

$$F_{AA} = e^{\left[\frac{B}{(\Theta_{H,R}+273)} - \frac{B}{(\Theta_{H}+273)}\right]}$$

where:

F_{AA} = insulation aging acceleration factor

B = is a design constant, typically 15000, °C

$\Theta_{H,R}$ = winding hottest-spot temperature at rated load (95°C if $\Delta\Theta_{W/A,R}$ = 55°C 110°C if $\Delta\Theta_{W/A,R}$ = 65°C)

$\Delta\Theta_{W/A,R}$ = average winding rise over ambient at rated load (setting)

Daily Rate of Loss of Life

Now we calculate daily rate of loss of life (RLOL, percent loss of life per day) for a 24-hour period as follows:

$$RLOL = \frac{F_{EQA} \bullet 24}{ILIFE} \bullet 100$$

where:

RLOL = rate of loss of life in percent per day

ILIFE = expected normal insulation life in hours

To provide the user with trend information on the loss of insulation, the RLOL value should be automatically recorded.

The equivalent life at the reference hottest-spot temperature (95ºC or 110ºC) that will be consumed in a given time period for a given temperature cycle is:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA_n} \bullet \Delta t_n}{\sum_{n=1}^{N} \Delta t_n}$$

where:

F_{EQA} = equivalent insulation aging factor for a total time period

n = index of the time interval, Δt

N = total number of time intervals for the time period

F_{AA_n} = insulation aging acceleration factor for the time interval, Δt_n

Δt = time interval

During 24 hours, the total number of time intervals is:

$$N = \frac{24}{\left(\frac{\Delta t}{60}\right)} = \frac{1440}{\Delta t}$$

where:

Δt = time interval

Because the time intervals and the total time period used in the thermal model will be constant, we can simplify the calculation of F_{EQA} to the following:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA_n}}{N} \qquad \text{(equivalent life in days)}$$

Total Accumulated Loss of Life

An estimate of the total accumulated loss-of-insulation life in percentage of normal insulation life can be made by summing all of the daily RLOL values:

$$TLOL_d = RLOL_d + TLOL_{d-1}$$

where:

$TLOL_d$ = total accumulated loss of life, TLOL

$RLOL_d$ = most recent daily calculation

$TLOL_{d-1}$ = previous TLOL

Damage, or aging of insulation, roughly doubles with every 6–8ºC of temperature above 90ºC [5]. We can plot the approximate effects of hottest-spot temperature on insulation aging as shown in Figure 3.

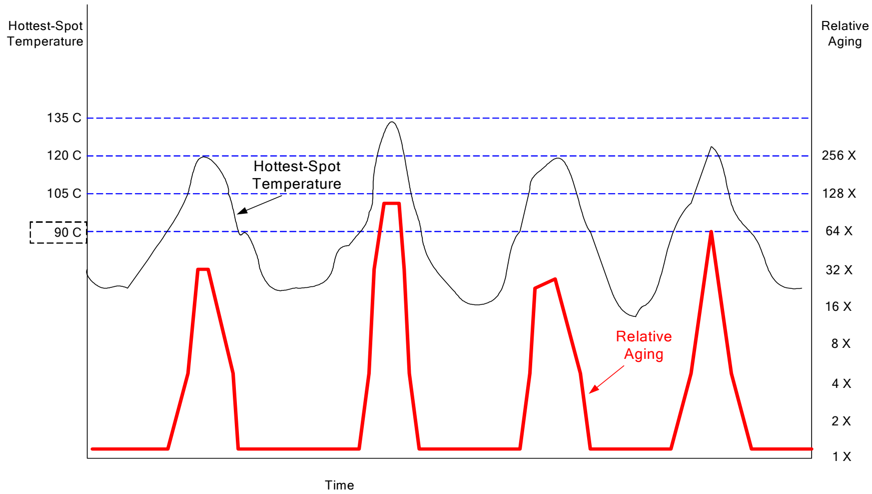

Figure 3 Relative Aging vs. Hottest-Spot Temperature

Accumulated loss of life provides an indicator of the impact of operational overloads on the transformer. Simply, it is the integral over time of the accumulated aging, taking into account the effect of accelerated aging caused by elevated temperatures.

Moisture content in the cellulose insulation has a significant impact on insulation aging [4] [6]. If the moisture content increases from 0.5% to 1.0%, the rate of aging of the cellulose insulation at least doubles for a given temperature. Moisture in the insulation can be estimated by applying an appropriate algorithm [7] to the measured water content in the oil. Because it is important to know the amount of water in the transformer oil, even an advanced temperature monitoring system cannot completely predict the perfect time to perform maintenance. Using the calculated moisture content to adjust the thermal aging of the insulation improves the ability to predict maintenance.

Comparing Calculated and Measured Values

While it is advantageous to have top-oil and hottest-spot temperatures available from direct measurements, calculated values are also useful. Obviously, for a transformer without top-oil or hottest-spot RTDs, a calculated value is the only one possible. The calculated values for top-oil and hottest-spot temperatures can be derived using load currents and either measured or fixed (manually entered setpoint) values for ambient temperature. When based on assumed ambient temperatures, the calculated values will be very unreliable.

If measured oil temperatures are available, then it is possible to compare the calculated values with the measured values. This gives an indication of the effectiveness of the cooling system. An alarm can be issued if the difference between measured and calculated temperatures exceeds a preset value. Failed pumps, bird's nests in the fans, or any number of other problems can be detected and corrected this way, before they cause a catastrophic transformer failure. Comparing calculated and measured values can also be used to correct setting constants.

THROUGH-FAULT MONITORING AND ALARMS

According to insurance industry studies [8], through faults are the number one cause of transformer failure today. Initiation of a through fault can be seen in Figure 4 below.

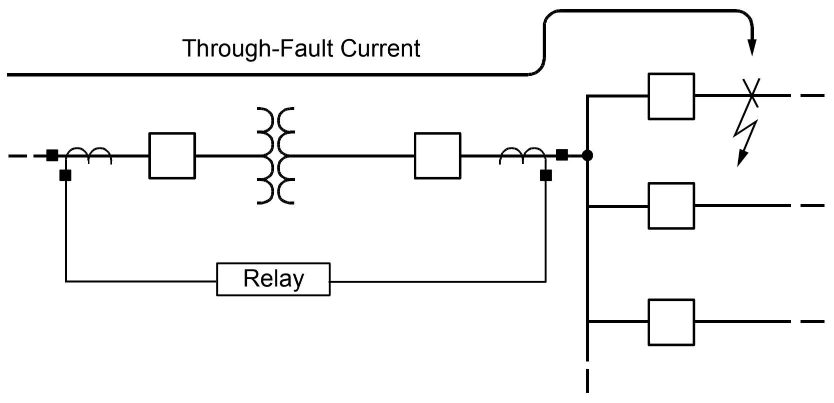

Figure 4 One-Line Diagram of a Typical Through-Fault Event

As fault duty and feeder exposure increase, the incidence and severity of through faults experienced by a transformer will tend to go up over time. IEEE Std. C57.12 [9] provides construction guidelines for short-circuit withstand for transformers. The standard states that a transformer shall withstand 2 seconds of a bolted fault at the transformer terminals. Testing to verify through-fault withstand capability is normally performed on a design basis, with the length of the test limited to 0.5 seconds for up to 30 MVA three-phase transformers.

When evaluating how to assess possible damage or loss of life to an installed transformer subjected to a through fault, it is interesting to consider testing standards and their implications. The test standards are "intended for use as a basis for performance [10]." Test standards are established only for new units, to some degree in recognition that normal service life of a transformer will cause it to have an unpredictable response to short-circuit tests; yet those tests are a simulation of what the transformer may experience with the next through fault.

Following short-circuit tests, a careful set of visual and electrical tests is performed to verify there has been no, or minimal, movement of the coils as a result of the forces incident to a short circuit. In an installed transformer, it is generally not practical to perform even minimal visual and electrical tests following every through fault. So the question is: what is a reasonable expectation of length of life of a transformer, built to accepted standards, following normal through faults that every system will experience?

Plotting a comparison of the stresses a transformer experiences and its withstand capability against time could produce a graph such as Figure 5 [6].

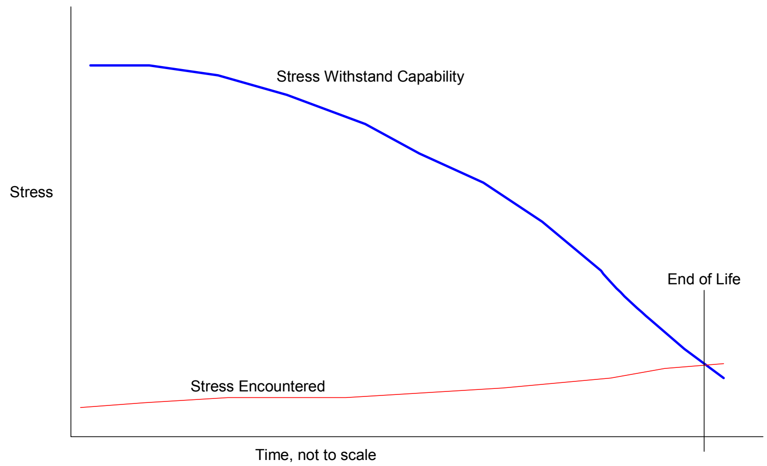

Figure 5 Stress Withstand Capability Over Transformer's Lifetime

The stress withstand capability of a transformer is reduced gradually by degradation caused by overheating of the insulation components. The stresses the transformer are subjected to may increase over time due to increasing loads and an increase in short-circuit duty from additional system interconnections and sources.

If we were to modify Figure 5 to include more detail, also shown by Reference [6], we could create a graph such as Figure 6.

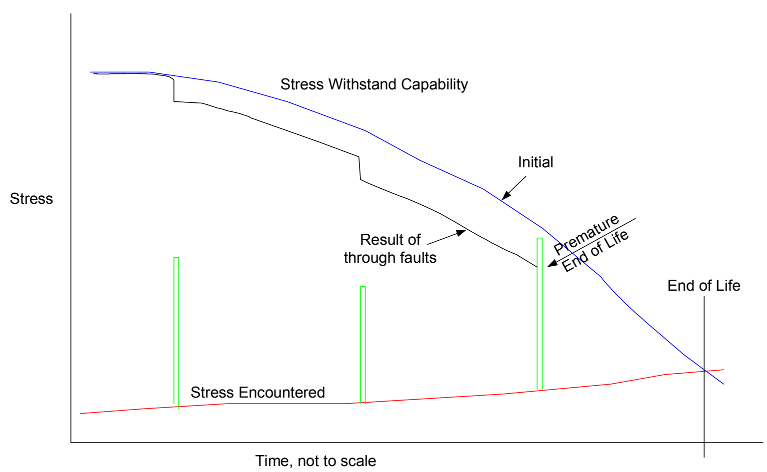

Figure 6 Stress Withstand Capability Over Transformer's Reduced Lifetime

In this case, the transformer experiences three severe through faults. The first two faults reduce the transformer's withstand capability to the point where it cannot withstand the forces of the third fault.

While not explicitly stated in IEEE standards (see [9]) this degradation in capability is predicted by the following equation [11]:

$$\mathrm{I}^2 t = k \tag{1}$$

where:

k generally equals a constant where t equals 2 seconds and I equals maximum fault current in per unit times normal base current. This matches the construction characteristics defined in IEEE Std. C57.12.

For example, for a transformer rated 40 MVA base rating, 230/69 kV and a 4% impedance connected to an infinite bus, we would have:

$$\text{Base load current} = \frac{40}{\sqrt{3} \bullet 69} = 0.335 \text{ kA}$$

Equation 1 with maximum fault current then becomes:

$$\left(\frac{40}{\sqrt{3} \bullet 69 \bullet 0.04}\right)^2 \bullet 2 \text{ sec} = 140 \text{ kA}^2 \text{ sec}$$

While this curve as presented in the IEEE standards [9] [11] is used for setting and coordinating protective devices for transformers, it can have practical applications to ongoing transformer service. In IEEE Std. C57.12, the transformer is constructed to be able to withstand this fault. This fault is the limit of what the transformer was designed to withstand; the testing standard provides for a design test of the transformer, when new, at a short-circuit duration of 1/4 of this time. Following the short-circuit test, the transformer is untanked and inspected visually for winding displacement or other damage. Electrical tests are performed to ensure insulation integrity and verify that parameters such as excitation current and impedance have not changed.

Users can measure and record the fault duty seen by a transformer on the same basis as the design tests performed in the factory. This gives the user a basis for evaluating the service life remaining in the transformer before inspection and testing are required.

Combined Measurements

Temperature loss-of-life calculations are based on a gradual and continual aging process similar to that shown in Figure 5. While sudden and severe overloading at high ambient temperature could cause a temporary increase in the aging “slope,” as long as the overload is not so severe as to burn up the transformer, the process is akin to sliding down a hill and not falling off a cliff.

On the other hand, a through fault is a sudden and severe event by its very nature. As shown in Figure 6, the mechanical forces incident to the through fault can cause an insulation structure that is already aged by years of loading to fail.

The problem is that overloading guidelines do not take into account the short-circuit stresses that a transformer may have or may yet experience. Likewise, short-circuit design and testing standards are made for new units that have not experienced any aging of the insulation structure. The advantage of having one device perform both the thermal recording and loss-of-life calculation, as well as the through-fault monitoring and accumulated fault duty recording, is that now these two factors can be combined for an effective maintenance indicator.

For example, if we define TLOLL = Total Loss-of-Life Limit and ISQT = Accumulated I^2t of fault duty, we can write a logic equation to initiate alarm for a transformer similar to that in the through-fault monitoring example:

Alarm = (TLOLL > 70%) AND (ISQT > 98 kA^2 seconds)

This alarm can be a sign that because the transformer has an accumulated thermal loss of life of 70% as well as an accumulated through-fault duty of 70% of its nominal withstand capability, it is time for at least a thorough inspection and possibly an overhaul to reblock or even rewind.

A possibly greater application is to use the outputs from the monitoring associated with electrical quantities with other transformer information that may be available. These other monitoring devices or methods can include sudden pressure relays, thermal imaging, and dissolved gas analysis.

Sudden pressure relays have been reported to have occasional problems with misoperation on external faults. For this reason, they are sometimes used for alarm only and not tripping [12]. An alarm from a sudden pressure relay may have more consequence as a maintenance predictor if coupled with an accumulated loss of life due to overload. Within a digital relay, it is a simple matter to either logically or electrically combine the output of the sudden pressure relay with the accumulated loss-of-life alarm. This allows recognition of degradation in insulation, making small movements of the core and coil assembly more significant, and possibly, events worthy of initiating an inspection.

Thermal imaging can be used to compare calculated top-oil temperatures with measured values, as suggested in the thermal monitoring section above. Cooling effectiveness, or the lack thereof, can then be evaluated prior to damage.

Dissolved gas analysis is more suited to be an interim step between an accumulation of events and a complete inspection than as a frequent diagnostic action, except on the largest transformers.

Turning Data Into Information

It is not enough that data on overall loss of life exist inside a relay. It must be transmitted to a person who can use the information to improve decision-making and better manage the transformer asset. The simplest way to send data is to assign an alarm contact to a certain loss-of-life level. The problem is that this takes away the additional intelligence that may be available, as discussed in previous sections. Using a communications processor to send a complete report to a responsible engineer is a way to send more useful information (Figure 7).

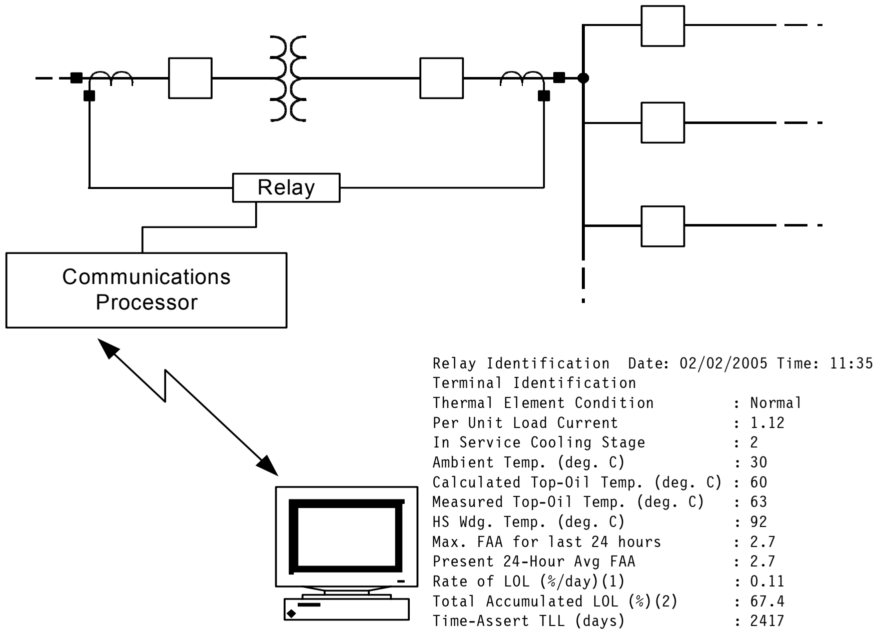

Figure 7 Using a Communications Processor to Send a Formatted Report

With more complete information, the engineer can assess the degree of risk associated with continuing with the transformer in service under the same conditions or performing maintenance. Combining multiple reports—such as thermal, through-fault, and online dissolved gas analysis—can give the best view of the conditions within the transformer.

CONCLUSIONS

While using the alarm point as a maintenance indicator may sound like additional work, doing so can actually prevent maintenance work. If a unit has not experienced an accumulated life duty to indicate that maintenance is necessary, then without some other indicator, maintenance is not necessary.

Transformers need to be utilized to their maximum capabilities, which mandates that maintenance actions and operating procedures take the consequences of maximum usage into account. Utilities that use all of the information available can postpone maintenance on units that have not seen excessive stress and accelerate maintenance schedules for units that have seen possibly damaging stress.

As transformer design tools improve, they not only provide for designs that are more assured of meeting standards, but they also allow transformer designers to avoid safety margins that may have existed in prior designs. This makes it more important to recognize what these design standards provide and how to measure when the limits defined by standards are approached.

1. A comprehensive transformer management plan continuously monitors and records thermal loading.
2. Comparing measured top-oil temperatures with calculated top-oil temperature provides a measure of cooling effectiveness that can be used to notify maintenance personnel of problems with fans or pumps.

3. Accumulated through-fault monitoring can be an indicator of necessary maintenance, just as accumulated thermal loading can.
4. Combining through-fault, temperature, and other factors can optimize maintenance practices for an overall reduction in total ownership costs.

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BIOGRAPHIES

Roy Moxley has a B.S. in Electrical Engineering from the University of Colorado. He joined Schweitzer Engineering Laboratories in 2000 as market manager for transmission system products. He is now a senior product manager. Prior to joining SEL he was with General Electric Company as a relay application engineer, transmission and distribution (T&D) field application engineer, and T&D account manager. He is a registered professional engineer in the State of Pennsylvania.

Armando Guzmán (M ‘95, SM ‘01) received his BSEE with honors from Guadalajara Autonomous University (UAG), Mexico, in 1979. He received a diploma in fiber-optics engineering from Monterrey Institute of Technology and Advanced Studies (ITESM), Mexico, in 1990, and his MSEE from University of Idaho, USA, in 2002. He served as regional supervisor of the Protection Department in the Western Transmission Region of the Federal Electricity Commission (the electrical utility company of Mexico) for 13 years. He lectured at UAG in power system protection. Since 1993 he has been with Schweitzer Engineering Laboratories in Pullman, Washington, where he is presently a Fellow Research Engineer. He holds several patents in power system protection. He is a senior member of IEEE and has authored and coauthored several technical papers.

APPENDIX A: EXAMPLE SETTINGS

This table includes example thermal settings for a relay protecting a three-phase transformer with one RTD for ambient temperature and one RTD for top-oil temperature. **Bold items can be selected as default values if actual values from the transformer manufacturer are not available.**

Setting	Range	Value
ETHER Enable Thermal Elements	Select: N, Y	Y
E49A Enable RTDA Elements	Select: N, Y	N
MVA Maximum Power Xfmr Capacity	OFF, 0.2–5000.0 MVA	100.0
49A01A RTD 1A Alarm Temperature	OFF, 32–482 F	OFF
49T01A RTD 1A Trip Temperature	OFF, 32–482 F	OFF
49A02A RTD 2A Alarm Temperature	OFF, 32–482 F	OFF
49T02A RTD 2A Trip Temperature	OFF, 32–482 F	OFF
TMWDG Thermal Model Winding Current	Select: 1–4, 12, 34	1
VWDG Winding LL Voltage	1–1000 kV	230.00
XTYPE Transformer Construction	Select: 1, 3	3
TRTYPE Transformer Type	Select: D, Y	Y
THwr Winding Temp/Amb	Select: 65–55	65
NCS Number of Cooling Stages	Select: 1–3	3
MCS11 Cooling Stage 1 Rating	0.2–5000 MVA	100.0
MCS12 Cooling Stage 2 Rating	0.2–5000 MVA	140.0
CS12S Cooling Stage 2 (SELOGIC® control equation)		0
MCS13 Cooling Stage 3 Rating	0.2–5000MVA	170.0
CS13S Cooling Stage 3 (SELOGIC control equation)		0
DTMP Default Ambient Temp	–40 to 85°C	15
TRDE De-Energized Transformer (SELOGIC control equation)		0
NTHM Number Thermal Inputs	0–4	2
AMB Ambient Temperature	Select: THM1, THM2, THM3, THM4, RTD1A, RTD2A, RTD3A, ..., RTD12B	RTD1A
OIL1 Oil 1 Temperature	Select: THM1, THM2, THM3, THM4, RTD1A, RTD2A, RTD3A, ..., RTD12B	RTD2A
TOT1 Top-Oil Temp Limit 1	50–150C	100
TOT2 Top-Oil Temp Limit 2	50–150C	100

HST1 Hot-Spot Limit 1	80–300C	200
HST2 Hot-Spot Limit 2	80–300C	200
FAAL1 Aging Acceleration Factor Limit 1	0.00–599.99	50.00
FAAL2 Aging Acceleration Factor Limit 2	0.00–599.99	50.00
RLOLL Daily Loss-of-Life Limit	0.00–99.99%	50.00
TLOLL Total Loss-of-Life Limit	0.00–99.99%	50.00
CSEP1 Cooling System Efficiency-Transformer 1	5–100C	15
ILIFE Nominal Insulation Life	1000–999999 hr	180000
EDFTC Enable Default Constants	Select: N, Y	N
Ths1 Hot-Spot Thermal Time Constant	**0.01–2 hr**	**0.08**
BFFA1 Constant to Calc. FAA	**0–100000**	**15000**
THor11 Top-Oil Rise/Amb	**0.1–100C**	**55.0**
THgr11 Hot-Spot Cond. Rise/Top-Oil	**0.1–100C**	**25.0**
RATL11 Ratio Losses	**0.0–100**	**3.2**
OTR11 Oil Thermal Time Constant	**0.1–20 hr**	**3.0**
EXPn11 Oil Exponent	**0.1–5**	**0.8**
EXPm11 Winding Exponent	**0.1–5**	**0.8**
THor12 Top-Oil Rise/Amb	**0.1–100C**	**50.0**
THgr12 Hot-Spot Cond. Rise/Top-Oil	**0.1–100C**	**30.0**
RATL12 Ratio Losses	**0.0–100**	**4.5**
OTR12 Oil Thermal Time Constant	**0.1–20 hr**	**2.0**
EXPn12 Oil Exponent	**0.1–5**	**0.9**
EXPm12 Winding Exponent	**0.1–5**	**0.8**
THor13 Top-Oil Rise/Amb	**0.1–100C**	**45.0**
THgr13 Hot-Spot Cond. Rise/Top-Oil	**0.1–100C**	**35.0**
RATL13 Ratio Losses	**0.0–100**	**6.5**
OTR13 Oil Thermal Time Constant	**0.1–20 hr**	**1.3**
EXPn13 Oil Exponent	**0.1–5**	**1.0**
EXPm13 Winding Exponent	**0.1–5**	**1.0**

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