ELECTRIC POWER RESEARCH INSTITUTE

EPRI Transformer Guidebook Development: The Copper Book

Chapter 8: Transformer Maintenance

2011 TECHNICAL REPORT

8
TRANSFORMER MAINTENANCE

The text that follows will become Chapter 8 of the Copper Book. The content is near final, but it is expected that some changes will be made based on feedback from EPRI members after this report is published. Changes will continue to be made until the Copper Book is published. The text is in a format suitable for conversion to the final two column format of the Copper Book and the paragraphs are numbered accordingly.

8.1 Introduction

Utility engineers face a daunting array of challenges unrelated to equipment design or aging in their quest to maintain and extend the life of their transformers. Competitive business concerns drive many utilities to seek out every possible economy resulting in a continuing need to minimize operating and maintenance costs to meet new corporate targets. Experienced personnel have retired and not been replaced. At the same time, pressure to improve customer satisfaction, maintain or increase reliability, and address new environmental concerns grows. Industry restructuring continues. Formation of Regional Transmission Organizations (RTO) and Generation Companies (GENCO) produces new stakeholders interested in all aspects of transformer operation and maintenance. Outages for routine maintenance are becoming more difficult to obtain. Regulators are focusing on equipment performance and reliability. Federal Energy regulatory Commission (FERC) and North American Electricity Reliability Corp (NERC) are continuing to broaden requirements related to maintenance (see Appendix 8G, North American Electric Reliability Corporation (NERC) Reliability Standards). Meanwhile, much of the T&D and plant infrastructure is approaching the end of its design life and uncertainty over future returns has resulted in a reduction in the capital available for new investments. The desire to optimize asset utilization and extend equipment life continues to grow. In turn, life extension is considered by many to be the natural result of a well-founded, consistently applied maintenance program. For maintenance personnel, as in other aspects of utility operation, “business as usual” is no longer acceptable. In the past, maintenance was considered a routine, almost second-class, activity. Now, the value of a good maintenance program is widely recognized. The science of maintenance engineering has progressed and the industry has responded by developing new tools and adopting methodologies from other sectors. The planning and construction of a well-developed maintenance program is as important as is specific equipment knowledge to the power delivery system.

The industry has broadly accepted the need for collecting more accurate maintenance data and integrating individual maintenance and life extension decisions into more formal programs, often called asset management. A strongly conceived maintenance program is required to satisfy customers and regulators, effectively utilize resources, and provide the best possible reliability and availability.

- LTC present tap position and maximum and minimum drag hand readings (reset drag hands)
- In the case of transformers operating in parallel, the discrepancy of tap positions of the multiple transformers
- Readings from any on-line monitors

A detailed visual examination of the transformer components should also be conducted during an equipment outage. This would primarily consist of a “close in” inspection of the components that are not accessible when the transformer is energized. This typically includes those items on the routine inspection and the top surfaces of the unit adjacent to normally energized equipment.

8.8.3 Internal Inspections

From both a cost and transformer reliability point of view, it is not desirable to drain the oil and breach the transformer tank unless absolutely necessary. Whenever the windings and insulation are exposed to the outside environment, the probability for problems upon re-energization increases. However, there are instances where an internal inspection might be necessary in light of a potential fault or if the condition assessment testing indicates an abnormal condition. Also, there may be occasions where the oil must be drained for other reasons (field dryout, oil processing, bushing replacement). In these rare instances, it is a good idea to take advantage of the opportunity to perform an internal inspection, if possible. Some utilities perform pre-inspection testing and post-inspection testing to ensure that no damage has been done during the inspection. Tests that have been used are: winding resistance, capacitance and power factor, insulation resistance, turn ratio, DGA, and oil quality.

8.8.3.1 Preparation

Refer to Appendix 8B, Protection, Draining, and Refilling of Power Transformers, for the necessary procedures when preparing for an internal inspection. It is important that all personnel entering the transformer are properly trained and experienced. Foreign material controls need to be established at the highest level for internal inspections. Tool logs, controlled entry area and log, etc. should all be established ahead of time. Entry should be limited to required personnel only, others can review digital images.

A transformer is a very confined and dangerous space. Safety precautions must be followed to ensure an adequate supply of breathable air. Personnel safety is beyond the scope of this document, so appropriate sources should be consulted for the requisite precautions. From a transformer reliability standpoint, it should be pointed out that any air used to purge the transformer should be certified dry air only.

Before entering a transformer, personnel should:

1. Remove all loose objects from clothing (metal or otherwise).
2. Remove rings and watches from person.

ELECTRIC POWER RESEARCH INSTITUTE

2010 TECHNICAL REPORT

EPRI Transformer Guidebook Development: The Copper Book

Chapter 9: Monitoring and Diagnostics

9
MONITORING AND DIAGNOSTICS

9.1 Introduction

Utility personnel have always sought ways to assess the general condition of their transformers and components and to identify specific problems. Over the years, diagnostic tests have been developed, based on the available technology.

In recent years, a more sophisticated means has evolved for collecting a great deal of diagnostic information while the equipment is in service. This is known as continuous or on-line monitoring, which, when used expediently can overcome some of the fundamental limitations of diagnostics that rely only on off-line tests and other data. However, it is most important for utilities to holistically review all of the information and pertinent data available about the type of equipment being assessed. This includes vendor information and bulletins; industry operating experience (including fleet, plant and equipment history); abnormal and adverse ambient and environmental conditions; events that expose the transformer to stressors; indications of problems from operator rounds, maintenance activities and engineering walk-downs; as well as the data from sensors, on-line monitoring systems, oil samples, test results, etc. Monitoring all of this data is important and necessary to obtain complete diagnostic information on the condition of the transformer and its components.

Data monitoring, trending, and the associated diagnostic tools, can be used to assist in developing new strategies or changing existing strategies such as those that dictate operational limits, maintenance programs, additional testing or monitoring, and replacement decisions. Strategic enhancements can increase the performance and reliability of transformers, reduce maintenance costs, and aid in the optimization of transformer operation and maintenance procedures.

Note that, in general, on-line monitoring cannot be used to predict end of life; however, it will help show up deteriorating conditions that can lead to premature failure so that timely replacement decisions before failure can be made.

9.2 Scope

The information in this section is intended to provide an overview of the types of data and parameters that can be monitored and trended to help assess performance issues, equipment and component health, the need to perform or adjust maintenance activities, and to determine when equipment replacement should occur. It provides guidance on a technical basis for developing or refining inspection sheets, walk-downs, and testing and monitoring programs for transformer assets.

reliable the answers. Generally, at least one year should be simulated. If hourly data is not available, the simulation should be performed at as high a temporal resolution as the data will allow.

Once the hot spot temperatures are estimated, the aging rate is calculated using an Arrhenious reaction rate equation of the form:

$$F_{AA} = e^{\left(\frac{A}{(\theta_{HS,R}+273)} - \frac{A}{(\theta_{HS}+273)}\right)}$$ **Equation 9-17**

Where F_{AA} is the insulation aging rate

A is a constant equal to 15,000 for most insulation types

$\theta_{HS,R}$ is the reference hot spot temperature for the insulation

θ_{HS} is the hot spot temperature at which aging is evaluated

Once the aging rate is calculated, the cumulative aging for a given time period is calculated by integrating the aging rate over time:

$$\%LOL = \frac{\sum F_{AA}.t}{Expected\ \ Life} \text{ x } 100$$ **Equation 9-18**

Where t is the number of hours at the hot spot temperature

Expected life is a value depended on the definition used for end of life.

See IEEE C57.91 "Guide for Loading" for more information.

The results will be greatly affected by the assumptions made. However, any estimate is generally better than no estimate at all, provided the estimate is accompanied with a recognition of the uncertainty in underlying assumptions and methodology. For example, if the only data available is a monthly drag-hand reading from a winding temperature indicator that was last calibrated in 1972, it may be best to do some further testing or analysis before making a decision to repair or refurbish the unit.

General guidelines:

- Wherever possible, use historical data over period of at least one full year.
- When historical load data is not available, estimate average and peak loading, run analysis for both. Take the result with a grain of salt.

9.8.1.2 Degree of Polymerization Measurements from Paper Samples

If more conclusive results are necessary, and other analysis is highly uncertain or contradictory, an internal inspection with sampling of the paper for DP analysis might be a possible next step. This is a risky and costly endeavor and should only be considered as a last resort after careful deliberation. Also bear in mind that the DP of the insulating paper varies significantly throughout the transformer due to temperature gradients. In addition, the layers of paper with the highest degree of aging are often the layers adjacent to the conductors, making them inaccessible for the purposes of sampling.

Cellulose is the principal constituent of insulating papers used in power transformers and the cellulose molecule is made up of a long chain of glucose rings. DP is the average number of these rings in the molecule. When paper is new, the DP is typically between 1000 and 1400, but as the paper ages thermally, the bonds between rings begin to break and the average length of the chain is reduced. The shortening of the chains is also associated with diminished mechanical properties (tensile strength, burst strength, elongation to rupture), so it is possible to relate D.P. to mechanical properties. A DP value of 200 is generally accepted to represent the level at which "useful mechanical properties" of the paper are lost, so this may be used as an insulation life end-point [McNutt, W. J., 1992].

The degree of polymerization measurement is made in a chemical laboratory on a small sample of paper from the transformer whose condition is to be assessed. First the paper must be cleaned of its impregnating oil; then it is dissolved in an appropriate solvent and then DP is determined from a viscosity measurement on the resultant solution. Different solvents may be used for this measurement, but for the United States the approved method is documented in ASTM D4243.

Since a paper sample is required to make the DP measurement, it is necessary to take the transformer off line and drain the oil. This action should not be undertaken just for the purpose of condition assessment. However, on any occasion on which it is necessary to go inside the tank for another purpose, the opportunity may be exercised to get one or more paper samples, provided proper precautions are taken. Also, when transformers fail and must be dismantled, the opportunity should be taken to obtain multiple paper samples for DP measurement. If samples are taken from a number of transformers of varying age on the same system, gradually a profile of insulation condition will emerge.

One might question why mechanical property tests should not be made rather than DP, once a sample is available. The answer is that mechanical tests require very specific sample shapes, which are of substantial size. A very small sample of any configuration is acceptable for the DP measurement. In addition, DP measurements are much more repeatable than measurements of mechanical strength.

DP samples should be taken from areas with the highest thermal stress and the lowest electrical stress. Therefore, the manufacturer or someone knowledgeable about the design details of the transformer should be consulted to determine the best location.

In general, the hottest and most aged conductor insulation will be at the top of the transformer, where the oil is hottest. Most utilities would be reluctant to attempt to take winding conductor insulation samples if the transformer is to remain in service, but a method for doing so has been proposed [Bassetto, A., 1991]. Some have suggested taking sample from lead insulation. The lead hot spot is deep within the insulation, at the conductor surface, so an appropriate sample must be taken. Doing so requires removing a fair amount of paper from the lead and the re-taping lead. Particularly for high-voltage leads, this is exceedingly risky. Proper taping of leads requires both the knowledge of how much insulation to apply and the skill to apply the tape with the appropriate amount of stretch. Applying to much tape will result in a hot spot on the lead. Applying too little tape will result in a dielectric weak spot. In addition, if the lead is contoured, there is a risk of disturbing the layers of foil or metalized-crepe used to contour the joints.

Others have suggested sampling turn insulation from the outer conductors of the winding (see Figure 9–47). The thin paper insulation on winding conductors will be at relatively uniform temperature at a given location in the winding, so an outer wrap would be satisfactory, (see References [Bassetto, A., 1990], [Bozzini, C. A., 1968] for variability of DP with sampling location). In addition, the insulation in this area has relatively low electrical stress. Insulation to ground would be provided by maintaining an appropriate strike distance from the tank wall. Access to the winding insulation, however, is often impeded by the outer pressboard wraps around the windings. In addition, only a small sample (1 cm^2) can be taken. This is suitable provided careful laboratory techniques are followed in analyzing the samples [Allen, D. M., 1993].

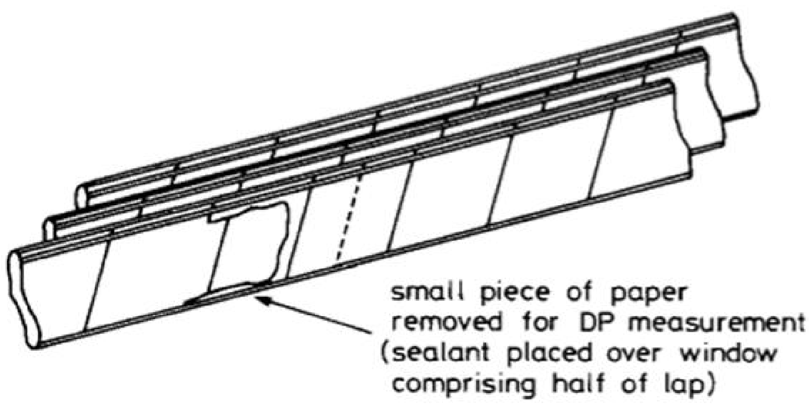

Figure 9–47
Taking DP Sample from Outer Wraps of Winding Turn Insulation [Allen, D. M., 1993])

Once a DP value has been determined, a translation is required to establish the relative age of the insulation. Such a translation technique has recently been proposed based on the following logic [McNutt, W. J., 1993]. Reduction of DP with aging time does not follow a linear pattern. It is very rapid at first, and then becomes more gradual. Shroff and Stannett observed that if any set of aging data is plotted with DP on a logarithmic scale and time on a linear scale, a straight-line results for the portion of the data after the initial rapid drop-off [Shroff, D. H. 1985]. The zero time intercepts for the straight lines range from DP = 700 to 900 for sets of test data at different temperatures and by various investigators. All of the data can be grouped by normalizing it based on the time required for DP to reduce to 200 (the life end-point). The resultant graph of normalized life versus DP is shown in Figure 9–48. The insulation age in years can also be estimated in equation form:

$$Insulation\ \ Age\ (years) = \left(\frac{1}{DP} - \frac{1}{1000}\right) \text{x}\, 4709$$ **Equation 9-19**

Note that the above equation assumes a starting DP of 1000.

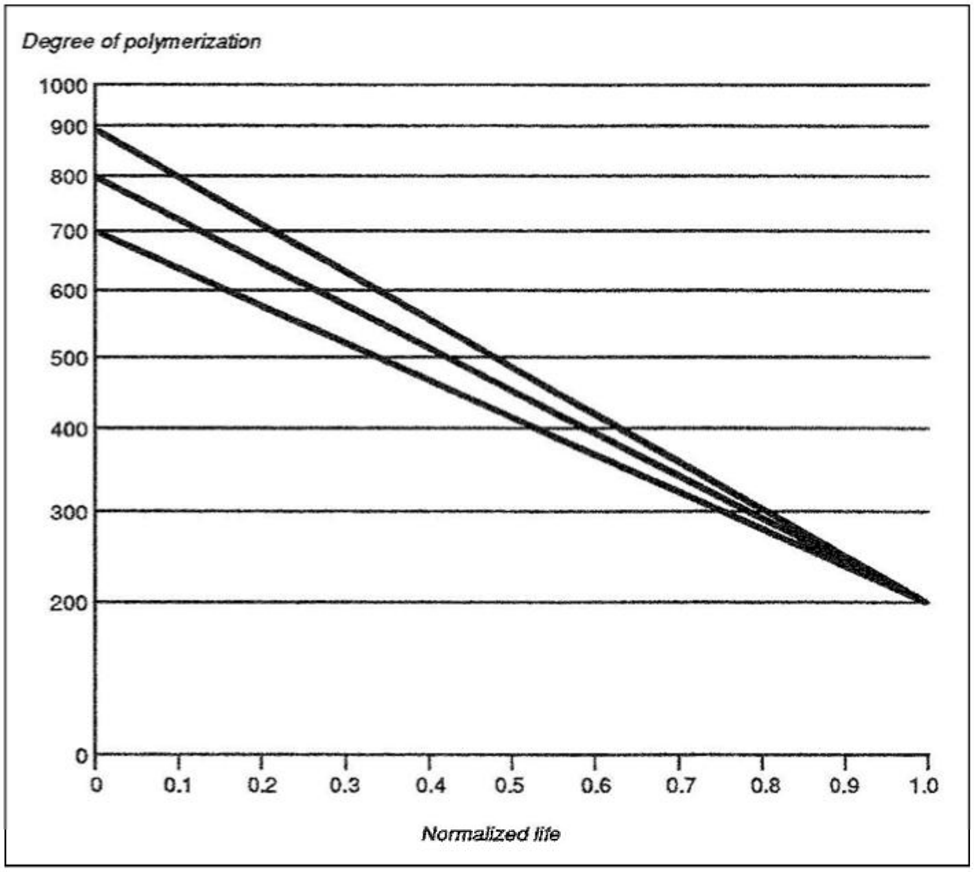

Figure 9–48
Normalized Insulation Life Consumption Versus Degree of Polymerization

The application of this curve can be understood by looking at a few examples.

1. Very aged transformer has insulation DP = 200. Figure 9–48 says that the Normalized Life = 1, or total insulation life has been consumed. That is what should be expected based on the life end-point definition of DP = 200.
2. Moderately aged transformer has insulation with DP = 500. Figure 9–48 says that the Normalized Life (or consumed life) is about 0.33, with a possible range of from 0.27 to 0.39. This insulation is still very usable and useful.
3. Transformer of moderate age, but with a history of very light loading, has DP = 800. Figure 9–48 says that the normalized life (or consumed life) is zero. This means that the insulation is still very young and has not yet reached the stabilized region of DP reduction.

This is admittedly an approximate method for assessing the condition of the transformer insulation, but it produces an answer that should be of adequate quality to make engineering judgments. For example, a transformer with insulation DP = 300 would not be a good candidate for extensive refurbishment, because about 70% of the insulation life has already been consumed.

One of the obvious issues with DP measurements is the requirement of having a sample of paper from the operating transformer. Obtaining the sample can be difficult since entry into the transformer is necessary. Subsequently, one attempts to obtain a sample from a region that would be susceptible to the aging process. With these limitations, the use of the non-invasive furan test previously discussed is very desirable.

9.8.1.3 Estimation of Aging Using Combined Information

Dealing with the uncertainty that accompanies life assessment of transformers is a difficult task. Doing so with a level of consistency and efficiency required for assessing a fleet of transformers is more difficult still. Proposed here is a simple method for estimating whether a transformer is in one of two discrete states: "serviceable" or "aged." While a quantitative estimate of life remaining is most desirable, it is at this point in time unrealistic given the variables involved, the lack of information typical with most transformers and the current unavailability of a safe, economic, and definitive test for the condition of the cellulose insulation. Therefore, simplifying the problem somewhat into two discrete states allows for a method which quantitatively (albeit very empirically) accounts for the varying uncertainty that accompanies life estimation.

9.8.1.3.1 Insulation Life Classification Procedure

This procedure uses a combination of several insulation life indicators. Each indicator is separately evaluated to produce a "belief" in whether the insulation is "serviceable" or "aged" based upon a simple linear interpolation between two limits. Below the first limit, the indicator gives a certain belief that the insulation is serviceable. Above the second limit, the indicator gives a certain belief that the insulation is aged. In between the two limits, the belief is a linear interpolation between the serviceable belief and the aged belief.

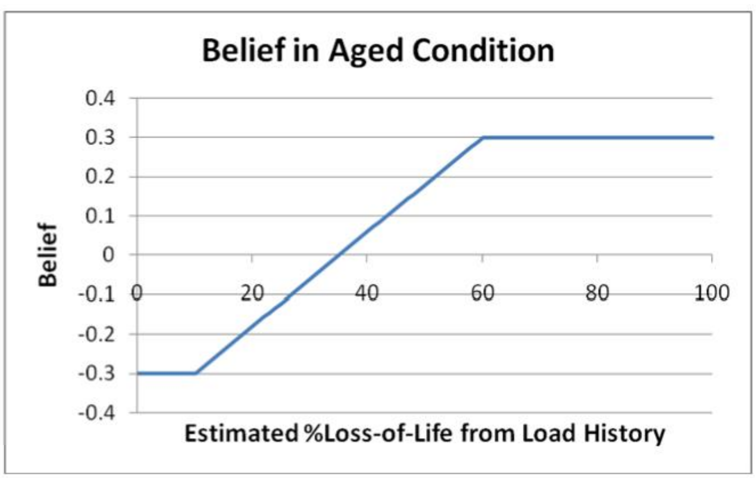

Figure 9–49
Belief Function for Estimated %LOL