Equipment Failure Model and Data for Substation Transformers

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PRODUCT DESCRIPTION

Asset management has become an increasingly important aspect of corporate business strategies. A significant focus of EPRI's asset management research in recent years has been to develop a rational basis for selecting repair or replacement options for specific classes of equipment by balancing the risks of equipment failure against the costs of continued maintenance or capital replacement.

Results & Findings

EPRI has developed a decision framework that enable utilities to generate business cases for these investments, which takes a life-cycle costing approach that enables corporate financial managers and regulators to assess the multi-year financial impacts of maintaining specific classes of power delivery infrastructure assets. One of the key drivers in these asset management decisions are the projected failure rates of the assets as they age.

The primary purpose of this report is to provide data on equipment failure mechanisms and preventive maintenance that can be used systematically to estimate failure rates of substation transformers.

Challenges & Objectives

Estimating equipment failures is a critical challenge to applying EPRI's asset management tools. Ideally, a utility's maintenance records would provide sufficient data to estimate them. However, in many cases, for a variety of reasons they are not. Ultimately, too, working collaboratively through EPRI, industry-wide equipment testing and failure analysis databases could be assembled to provide these estimates. However, given the scale and time that will be required to develop these databases, it is necessary to find some ways to provide failure information for asset management purposes in the interim. This report develops an alternative approach to estimating equipment failure rates by describing an equipment failure model based on a combination of expert judgment and available data.

Applications, Values & Use

This report provides preliminary baseline data on failure causes and for the calculation of failure rates of substation transformers. It is a companion to the report *Transformer Asset Management and Testing Methodology* (1012505) and the *Transformer Asset Management and Testing Model* v. 1.0 (1012504). These estimates can drive asset management decisions regarding the inventory of these components, including decisions on testing and maintenance intervals. Users of this information will be asset managers and analysts in development of economical strategies for maintenance of substation transformers.

EPRI Perspective

This report utilizes the EPRI PM Basis Database (EPRI 1010919), which was developed for EPRI's Nuclear Power Division. The broad objective of the PM Basis project is to develop a preventative maintenance basis for a large number of component types in utility power systems (including nuclear and fossil generating plants, transmission and distribution systems) using information supplied by the industry. This report uses the PM Basis equipment failure models for transformers, which defines how these types of components deteriorate over time and quantifies the rates at which deterioration occurs. The model thus permits projecting failure rates for each component type as a function of the various service conditions and stressors that may be present. One result of these calculations would be to establish failure rate data for use in asset management decision models. Other uses of the models include establishing condition and failure codes for use in data collection and tracking, and calibrating failure rates through use of such data.

Approach

The process used to develop a PM Basis for a component follows a well defined sequence of steps. The process utilizes a combination of the information developed by a panel of experts and further information derived from analysis performed using computerized algorithms resident in the EPRI PM Basis Database. Major process steps include: establishing the boundary of the equipment to be considered, identifying major subcategories, establishing the functional importance, service conditions, and duty cycles that influence equipment degradation, establishing failure locations, determining degradation processes, the factors that influence them, and their time characteristics, listing degradation discovery opportunities and their effectiveness, describing PM tasks and their effectiveness.

Keywords

Distribution
Substations
Transformers
Maintenance Optimization
Preventive Maintenance
Component Reliability

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1
INTRODUCTION

Background

The current state of the electric power industry has placed unprecedented strains on the assets used to deliver power to energy customers. Increasing pressure from both customers and regulators to maintain and enhance service reliability, while at the same time controlling costs, has put many distribution companies in a classic dilemma of conflicting objectives. Faced with this situation, companies are scrutinizing investment and maintenance expenditures much more rigorously than in the past. For that reason, asset management has become an increasingly important aspect of corporate business strategies.

A significant focus of EPRI's asset management research in recent years has been to develop a rational basis for selecting repair or replacement options for specific equipment by balancing the risks of equipment failure against the costs of continued maintenance or capital replacement. EPRI has developed several products (EPRI 1000422, 1001703, 1001704, 1001872, 1001873, 1002086, 1002092) that enable utilities to generate business cases for investments, evaluate risks, and focus scarce manpower and investment resources on high-value solutions. The decision framework embodied in these products takes a life-cycle costing approach that enables corporate financial managers and regulators to assess the multi-year financial impacts of maintaining specific classes of power delivery infrastructure assets.

In general, equipment failures accelerate as they age, and at some point, the costs of outages, repairs, and emergency replacements exceed the costs of planned replacements. With billions of dollars of utility power delivery infrastructure now nearing the end of its useful life, determining when to replace these assets is critical to the financial health of many utilities. Thus, some of the key drivers in these asset management decisions are the projected failure rates of the assets as they age.

The current focus of this research addresses asset management strategies for substation transformers. Work on this topic is proceeding in two parallel paths: 1) Develop an economic decision model for selecting least-cost strategies for managing substation transformers and 2) develop base-case data on transformer failure rates and other key parameters of the decision model. The prototype decision model is described in EPRI reports 1012504 and 1012505. The present report describes the base-case data.

Estimating equipment failures is a critical challenge to applying these decision tools. Ideally, a utility's maintenance records would provide sufficient data to estimate them. However, in many cases, for a variety of reasons they are not. Ultimately, too, working collaboratively through EPRI, industry-wide equipment testing and failure analysis databases could be assembled to provide these estimates. However, given the scale and time that will be required to develop these databases, it is necessary to find some ways to provide failure information for asset management purposes in the interim. This report develops an alternative approach to estimating equipment failure rates by describing a method for modeling equipment failures based on a combination of expert judgment and available data.

The primary purpose of this report is to provide base-case data on transformer failure rates and related parameters. In addition to baseline data, the report also summarizes the equipment failure model for transformers based on EPRI's PM Basis Database (EPRI 1010919). The intended use of these estimates is to drive asset management decisions regarding component inventory, including decisions on testing and maintenance intervals and on component replacement policies. Users of this information will be asset managers and analysts in the development of economical strategies for distribution class component management.

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DEFAULT TRANSFORMER FAILURE AND CONDITION PARAMETERS

This chapter develops the default parameters for the *Transformer Asset Management and Testing Model*; for a full description of those parameters, see the *User Guide* (1012504) and the companion report *Transformer Asset Management and Testing Methodology* (1012505).

Transformer Condition States

The *condition state* input data for the EPRI model is based on the results of test data gathered during EPRI Solutions transformer predictive maintenance surveys, conducted over the last five years throughout North America. The basis for the field testing consists of the following energized tests and inspections:

- Visual inspection & functional tests
- Partial discharge monitoring
- Infrared Thermography
- Dissolved gas analysis review
- Standard oil quality test review
- Vibration analysis

The expertise EPRI Solutions gained from undertaking hundreds of transformer surveys provides the expert judgment input into the overall condition analysis. This expertise combined with the data from the above tests determines the "health status" for each transformer, identify issues relevant to long term degradation, and sets a benchmark for future condition monitoring. The condition (*equipment health status*) for each transformer is represented by one of four condition criteria.

1. Acceptable (Green): No significant deviations from normal operating conditions are detected. Continue normal operations and monitoring. No maintenance action required.
2. Monitor (Blue): A condition is detected that needs to be monitored, tracked or trended. No maintenance action is required at this time. The action initiated is for tracking, trending and monitoring.

3. Marginal (Yellow): A minor deviations from normal operating conditions has occurred. There is little probability of damage or failure. Normal or modified operations and monitoring may be applied. NOTE: An action maybe initiated for corrective maintenance.

4. Unacceptable (Red): A serious deviations from normal operating conditions has occurred and there is a high probability for damage or failure; modified operations or removal from service may be required. An action is initiated for corrective maintenance.

The output from EPRI Solutions transformer surveys provides the transformer *condition states* used in the EPRI decision model.

EPRI Solutions approach to transformer condition ranking is similar to the expert judgment undertaken by utilities working in this area. These utilities are looking to provide a means of ranking transformers on the basis of proximity to “end-of-life”. The various utility approaches show oil tests: DGA, moisture, acidity, dielectric breakdown strength and furan analysis, together with power factor testing, carry a slightly higher weighting than other tests such as; bushing & ancillaries, tap-changer and transformer visual condition. Those utilities using a condition ranking approach typically rank their transformers in one of four categories. An example is shown below:

1. Good condition, no problems

2. Good condition, minor problems, i.e. minor leaks, limited corrosion

3. Poor condition, minor problems

4. Poor condition, major problems

The basis for the *condition state* data supplied by EPRI Solutions is very similar to criteria running in some utilities, and the concept of using diagnostic technologies to monitor changes in transformer state and trigger major maintenance activities is a strategy most utilities are adopting.

Transformer Maintenance Levels

EPRI Solutions has been involved domestically and internationally with many utilities setting up reliability centered maintenance and maintenance optimization programs. This insight in to the transformer maintenance strategies of utilities, and data from the EPRI maintenance basis database for transformers was used to define the *maintenance levels* for the EPRI decision model.

- **Good Maintenance:** A transformer tank visual inspection. Rotate sequence of auxiliary equipment. Infrared thermography inspection. DGA, Oil Quality, Furan analysis. Supervisory parameter monitoring. Oil pump and motor condition. Partial discharge. Sonic-ultrasonic noise analysis. Vibration & sound level. Power factor testing. Upon condition tests i.e. TTR, FRA, Excitation current.

- **Average Maintenance:** Main transformer tank visual inspection. Rotate sequence of auxiliary equipment. DGA, Oil Quality. Oil pump functional test. Power factor testing. Upon condition tests i.e. TTR, FRA, Excitation current.

- **Poor Maintenance:** Main transformer tank visual inspection. Oil Quality. Supervisory parameter monitoring. Oil pump and motor condition checks.

Stressors

Environmental stressors are based on the transmission system impact from likely weather scenarios found across North America. Operational stressors are based on transformer utilization. The definitions are taken from PM Basis.

Table 2-1
Description of Environmental and Operating Stressors

Environmental	Description
Average environment	Absence of severe conditions described below.
Severe environment	High or excessive humidity, excessive temperatures (high or low) or temperature variations, excessive environmental conditions (e.g. salt, corrosive, airborne contaminants), loaded near to or above nameplate capacity.

Operating	Description
Average utilization	Continuous operation with relatively infrequent load tap operation.
High utilization	Frequently cycled and frequent activation of load tap changer.

Transformer Hazard Rates

Base Case Hazard Function:

- **Steady state hazard:** Set at 0.01 failures per year based on industry failure rates of:
    - 1 to 1.5% for Substation Power Transformers
    - 1.5 to 2% for HV Auto Transformers
    - 2.5% for Generation Station Transformers

- **Onset of burnout:** Is based on EPRI Solutions exposure to utility transformer replacement strategies. Set at 30 years this is the mid point based on the assumption that an early onset of significant transformer unreliability is determined by some utilities to occur between 25 – 35 years

- **Hazard rate doubling time during burnout:** Set to 10 years based on the range of 25 to 35 years for the onset of significant unreliability.

Table 2-2
Base Case Hazard Function Parameters

Base Case (average)	Steady state hazard	Onset of burnout	Hazard Rate doubling time during burnout
Hazard Function (failures/year)	0.0100	30	10.00

Transformer Condition State Multipliers

Multipliers of the base case parameters to adjust for degraded condition states. Values follow the example of underground cables in *Guidelines for Intelligent Asset Replacement: Volume 3 – Underground Distribution Cables* (1010740), based on reasonable dielectric similarities between transformers and cables.

Table 2-3
Transformer Condition State Multipliers

	Multiplier		
Transformer Condition State	**Steady state hazard**	**Onset of burnout**	**Doubling time**
Acceptable (Green)	0.8000	1.20	1.30
Monitor or Watch (Blue)	1.0000	0.50	0.85
Marginal (Yellow)	1.0000	0.35	0.60
Unacceptable (Red)	1.0000	0.15	0.40

Stressor Multipliers

These figures were taken from EPRI cable model. However, the doubling time for severe utilization was changed to 0.40, based on EPRI Solutions experience.

Table 2-4
Stressor Multipliers

IMPACT OF STRESSORS

Stressor	Steady state hazard	Onset of burnout	Doubling time
	Multiplier		
Severe utilization	1.10	0.95	1.00
Severe environment	1.50	0.80	0.60

The effect of the combination of severe utilization and severe environment is computed in the model.

Condition State Evolution Over Time

The fraction of a transformer population found in each condition state over time, when cared for using an average maintenance strategy, is based on EPRI Solutions exposure to utility transformer replacement strategies. The percentage of transformers in each state is based on the assumption that an early onset of significant transformer unreliability is determined by some utilities to occur between 25 – 35 years and the latest onset of significant unreliability is forecast between 45 – 55 years.

The values shown table below are based on average maintenance test strategies.

Table 2-5
Occurrence Probabilities of Condition States

Maintenance= Good

TRANSFORMER CONDITION STATES
Fraction of transformer population in each state

Age	Acceptable (Green)	Monitor or Watch (Blue)	Marginal (Yellow)	Unacceptable (Red)
10	95%	4%	1%	0%
20	60%	15%	15%	10%
40	40%	20%	20%	20%
60	0%	25%	25%	50%

Maintenance=Average

TRANSFORMER CONDITION STATES
Fraction of transformer population in each state

Age	Acceptable (Green)	Monitor or Watch (Blue)	Marginal (Yellow)	Unacceptable (Red)
10	75%	15%	10%	0%
20	45%	20%	15%	25%
40	20%	20%	20%	40%
60	0%	0%	30%	70%

Maintenance=Poor (RTF)

TRANSFORMER CONDITION STATES
Fraction of transformer population in each state

Age	Acceptable (Green)	Monitor or Watch (Blue)	Marginal (Yellow)	Unacceptable (Red)
10	50%	20%	20%	10%
20	25%	25%	25%	25%
40	10%	10%	30%	50%
60	0%	0%	15%	85%

Test Accuracies

EPRI Solutions has undertaken hundreds of transformer and other substation equipment surveys using diagnostic testing technologies:

- Partial discharge monitoring
- Infrared Thermography
- Dissolved gas analysis review
- Standard oil quality test review
- Vibration analysis

This experience allows EPRI Solutions make an expert judgment on the accuracy of test data results for different test strategies.

The following three tables show some sample test protocols corresponding to good, average, and poor maintenance. The model allows the user to select one set of test accuracies.

Table 2-6
Test Accuracies with Good Maintenance

Maintenance = Good

Test Protocol Outcome

Actual Condition	**"Acceptable (Green)"**	**"Monitor or Watch (Blue)"**	**"Marginal (Yellow)"**	**"Unacceptable (Red)"**
Acceptable (Green)	0.80	0.10	0.05	0.05
Monitor or Watch (Blue)	0.10	0.70	0.15	0.05
Marginal (Yellow)	0.05	0.10	0.70	0.15
Unacceptable (Red)	0.05	0.05	0.10	0.80

Table 2-7
Test Accuracies with Average Maintenance

Maintenance = Average

Test Protocol Outcome

Actual Condition	**"Acceptable (Green)"**	**"Monitor or Watch (Blue)"**	**"Marginal (Yellow)"**	**"Unacceptable (Red)"**
Acceptable (Green)	0.60	0.20	0.10	0.10
Monitor or Watch (Blue)	0.15	0.50	0.20	0.15
Marginal (Yellow)	0.15	0.20	0.50	0.15
Unacceptable (Red)	0.10	0.10	0.20	0.60

Table 2-8
Test Accuracies with Poor Maintenance

Maintenance= Poor (RTF)

Test Protocol Outcome

Actual Condition	**"Acceptable (Green)"**	**"Monitor or Watch (Blue)"**	**"Marginal (Yellow)"**	**"Unacceptable (Red)"**
Acceptable (Green)	0.40	0.30	0.20	0.10
Monitor or Watch (Blue)	0.25	0.30	0.25	0.20
Marginal (Yellow)	0.20	0.25	0.30	0.25
Unacceptable (Red)	0.10	0.20	0.30	0.40

Cost Data

Table 2-9
Cost Data

	Estimate
Replace	$750K to $3000K
Overhaul	$150k to $1000K
Test	$5K to $15K
Failure	Determined by each user utility
Maintenance Cost Good	$3K
Maintenance Cost Average	$1.5K
Maintenance Cost Poor	$0.75K

Condition Data

Below is a distribution of transformer condition for ages 1944 – 2005. This information was taken from EPRI Solutions inspection of over two hundred transformers at various utilities between 2002 and 2006.

The data reflects an increase in transformer anomalies and their seriousness between ages 25- 35 years. This is inline with the assumption that an early onset of significant transformer unreliability determined by some utilities is seen to occur between 25 – 35 years. The latest onset of significant unreliability estimated by some utilities as between 45 – 55 years is not clear from this data.

Table 2-10
Condition of Transformers Found at Routine Inspection

	EPRI Solutions Condition of Transformers Found at Routine Inspection			
Transformer Year Installed	**Number found in Condition Green (Acceptable)**	**Number found in Condition Blue (Monitor)**	**Number found in Condition Yellow (Marginal)**	**Number found in Condition Red (Unacceptable)**
2001 – 2005	4	4	0	0
1996 – 2000	2	2	0	0
1991 – 1995	4	4	0	0
1986 – 1990	2	4	0	0
1981 – 1985	10	8	4	0
1976 – 1980	16	4	6	0
1971 – 1975	20	20	4	4
1966 – 1970	6	10	0	4
1961 – 1965	10	10	2	0
1956 – 1960	6	8	2	0
1951 – 1955	24	2	0	0
1946 – 1950	4	2	0	0

3

SUMMARY OF EPRI'S PM BASIS FOR TRANSFORMERS

Technical Approach

The process used to develop a PM Basis for a component follows a well defined sequence of steps. The process utilizes a combination of the information developed by the expert panel and further information derived from analysis performed using computerized algorithms resident in the EPRI PM Basis Database. The expert panel for the distribution class components contained in this report was composed of the individuals cited in the acknowledgements section of this report. The process facilitates the expert group reaching agreement on the details of the PM template and its supporting basis information. Major process steps are:

1. Review maintenance and failure cause data obtained from relevant industry documents to categorize failure types and to gauge the relative effectiveness of current maintenance practices.

2. Subdivide the component type into logical groups by design characteristics. The PM Basis database contains the following substation transformer types:

   - Transformer - Substation - LTC
   - Transformer - Substation - No LTC

   In addition, the database also contains the following generating station transformer types (not discussed in this report):

   - Transformer - Station Aux_Startup – LTC
   - Transformer - Station Aux_Startup - No LTC
   - Transformer - Station Load Center Oil Fill Bushing
   - Transformer - Station Load Center Solid Bushing
   - Transformer - Station MPT_GSU

3. Define the boundary of each component type for the purpose of the database. The boundary divides the component itself from equipment that is attached to it, and it basically represents the components that would ordinarily be included in an inspection and maintenance program.

4. For example: The boundary of a substation transformer with an LTC used for the purpose of this database is defined to include: transformer core and windings, pumps, controls, fans,

heat exchanger, load tap changers, surge and lightning arrestors, pressure relief valves, sensors, monitors, alarms, and current transformers.

5. Establish the functional importance, service conditions, and duty cycles that influence degradation and impact PM strategies for these component types.

   In general, duty cycle captures stressors on the equipment that result from intensity of use. Think, for example of a pump, for which a high duty cycle would indicate continuous use and low duty cycle would indicate occasional use. In general, service condition captures stressors on the equipment that result from the operating environment.

6. Establish a preliminary PM task list (that is, inspections and tests) to assist in defining how failure causes can be discovered.

7. Divide the component into major maintainable subgroups.

8. Establish failure locations. Failure locations are the places on a component where degradation can occur.

9. Determine degradation processes, the factors that influence the degradation, and the time characteristics of the progression to failure.

   Degradation processes represent the various ways in which a component deteriorates over time. Degradation Mechanisms and Influences that may be experienced at each Failure Location are presented in adjacent columns of the failure model tables presented below (denoted 3.X.3). Each failure location may have one or more degradation mechanisms acting upon it, and each degradation mechanism may have more than one influence affecting it. Each degradation influence may determine a different timing characteristic of a particular mechanism. In general, degradation mechanisms are assumed to proceed independently of one another.

   The influence factors may also include particular stressors that, if they are present to an uncommon degree, can accelerate the progression of degradation by a particular mechanism. For instance, in the Air Gap type of Circuit Breaker, temperature influences the two degradation mechanisms, 1) the deterioration of insulation, and 2) the hardening of lubricant, so that if the circuit breaker is operated in an unusually hot environment these degradation mechanisms will proceed more quickly than the time code (described below) indicates.

   The time code column in the of the failure model tables presented in chapter 3 represents the rate at which deterioration occurs by the particular mechanism under the influence shown in the preceding failure location, degradation mechanism, and degradation influence columns. It can be thought of as the expected time until the earliest failures of the equipment occur due to that mechanism. The time codes are discussed below.

At this point in the process, one has defined an *equipment failure model* for one of the substation transformer component types. That is, such a model defines how the individual component type deteriorates over time, and quantifies the rates at which deterioration occurs. The model thus permits projecting failure rates for the component as a function of the various service conditions and stressors that may be present. One result of these calculations would be to establish failure rate data for use in the asset management models discussed above. Other uses of the models include establishing condition and failure codes for use in data collection and tracking, and calibrating failure rates through use of such data. Of course, a primary use of the model is to establish a preventative maintenance basis for the equipment. The remaining steps of the process address that function.

10. List the discovery opportunities for each of the subcomponent failure locations. Discovery opportunities mean inspections and tests that can be applied to determine the extent of deterioration. As is well known, most of the inspections and tests that can be applied do not unambiguously indicate the extent of deterioration, the true extent of which may be unobservable. For instance, the presence of air leaks in air compressor tubing and fittings on Oil-filled Circuit Breaker may not be fully discoverable by visual inspection alone. Therefore, the effectiveness of each test was also rated by the expert panel.

11. List the final PM strategies and tasks considered by the expert panel to be effective in discovering degradation and preventing the onset of the failure mechanism, or in returning the component to an as new condition through accepted preventive maintenance techniques. These PMs for these components are considered to be common practices in the industry but should not be considered recommended practices; each utility must evaluate the cost effectiveness of these practices in light of their own circumstances.

12. List the effectiveness (high, medium, low) of each PM task for addressing each degradation mechanism using high or H equal to 97%, medium or M equal to 80%, and low or L equal to no more than 50/50 chance of detecting a problem should it exist at the time the task is performed.

13. Describe the objective and scope of each PM task.

14. Develop a maintenance template providing PM tasks and task intervals which summarize the information developed in the previous items.

15. Develop a list of recent and relevant industry references.

The recommended Template task intervals are moderately conservative values intended to be default values for the case when a utility has no basis for its existing task intervals. They are based on a synthesis of current utility experience and may not be suitable for direct application by a given utility without careful consideration of its own service history. It is essential for utilities to continue to adjust intervals based on their own service experience. The information most likely to be useful to assist in this process would be information on as-found equipment condition.

Explanation of Failure Models

This chapter provides an explanation of the contents of the failure models in PM Basis and presented in detail tables 3-1 and 3-2. The data is provided in tabular form and structured into logical groupings that together represent useful information on where and how these components degrade over time.

For each of the component types discussed in this report, the data along with the results obtained by utilizing the PM Basis Database tools is presented in three convenient tables: Definitions, PM Template, and the component's Degradation Data Table. The process was necessarily fairly repetitive to ensure that each set of circumstances (i.e. component failure location and degradation mechanism) was given proper consideration.

Using the process described above, an expert group developed for each component the following information:

1. *Definitions* describing the component's boundary and the reasons for performing maintenance - its functional importance (herein called criticality), duty cycle and service conditions.

2. *Component Degradation Data* table describing where and how these components degrade over time.

Definitions: Boundary Definition, Functional Importance, Duty Cycle, and Service Condition

The boundary definition provides a simple description of what the expert group felt was included within the scope of the preventive maintenance program they recommended for each of the component types in this report. The boundary definition serves to divide the component itself from equipment that is attached to it, and it basically represents the components that would ordinarily be included in an inspection and maintenance program.

The reason for and the extent of the preventive maintenance performed on a given component can be explained by the functional importance it has, and the service conditions and duty cycles it experiences that influence its rate of degradation. All three of these are used to establish the PM strategies which might effectively be applied to these component types described in this report.

Functional importance or criticality defines whether or not the equipment is considered important enough from a production or financial stand point to require a comprehensive or a minimal maintenance program in order to maintain that equipment's ability to function reliably. The fullest extent of the recommended maintenance program would therefore be brought to bear on equipment judged to be critical, while equipment of lesser functional importance would receive a smaller, less expensive PM program.

Duty cycle captures stressors on the equipment that result from intensity of use. For example think of a pump for which a high duty cycle would indicate continuous use and a low duty cycle would indicate occasional use. In general, service conditions capture stressors on the equipment that result from the operating environment.

Component Degradation Data Table

The data gathered for each of the component types is presented as a tabular summary of the equipment failure models, including degradation and failure mechanism information obtained by direct interviews with the expert panel members in a joint workshop format. The data obtained represents the panel's opinions of the factors that influence failure: 1) where failures are most likely to occur, 2) the degradation mechanisms, 3) the factors that influence the degradation, 4) how the degradation progresses over time, 5) the opportunities to recognize the onset or status of the degradation, and 6) the PM actions and strategies that can be employed to discover or prevent the failure from occurring, and the effectiveness of these activities.

The component degradation data table identifies the many failure locations which, in their maintenance experience, the expert group knows to have occurred. The group went on to identify the leading degradation mechanisms, the main physical influences on the degradation, and the time progression of the degradation for each failure location. For each case (i.e. failure location, degradation mechanism, and degradation influence – the first 3 columns in each table), the expert group considered the time scale when the degradation would actually become a failure (coding this information is described below). This information is presented in the first four columns of each component's degradation data table.

The next columns in the table describes how effectively specific PM tasks, e.g. infrared and other diagnostic testing, can detect a significantly degraded condition (these tasks are described in the section detailing the PM Template and Task Descriptions). Task effectiveness for the purpose of the EPRI PM Basis Database is defined as high, medium, or low. Each task is rated on how well it is seen as addressing each degradation mechanism using high or H equal to 97% chance of success in preventing the degraded condition from becoming an in-service failure, medium or M equal to 80%, and low or L equal to no more than a 50% chance of detecting a problem should it exist at the time the task is performed.

The tables of detailed information presented here can also support utilities wanting to modify the suggested tasks or task intervals to account for their specific conditions.

Coding Time-To-Failure

The time code column in each component degradation data table represents the rate at which deterioration occurs by the particular mechanism under the particular influence shown in the preceding columns. It can be thought of as the expected time until the earliest failures of the equipment occur due to that mechanism. "W" time codes show the time in years that a wear-out mechanism typically takes to lead to the earliest failures – an analogue of minimum life. A range of years indicates uncertainty in this minimum life. When the W is not accompanied by a "U", it means the wear-out mechanism is not experienced by every component, but must be triggered by the existence of a special condition, or by another event, taken to be a random occurrence. In contrast, a "UW" code indicates a wear-out mechanism that is universally experienced and that starts to degrade the component as soon as it is put into service. An R in the time code indicates a randomly occurring degradation mechanism. Normally, the random mechanisms individually do not exert a strong influence on the failure rate, but their random occurrence pattern makes them hard to avert unless PM tasks are performed very frequently.

Component Data: Definitions, PM Templates, and Degradation Tables

This chapter presents the equipment failure model for **substation transformers with** and **without load tap changers**. Each of the component types can be found in its own subsection below. The major component subsections are then divided into two subsections which presents the information and analysis for each component type. The data found in each subsection is a follows:

Definitions

- Boundary Definition, Functional Importance, Duty Cycle, and Service Condition

Component Degradation Data Table and PM Strategies

- Failure Location, Degradation Mechanism, Degradation Influence, Time Code, and Discovery/ Prevention Opportunities

Transformer - Substation - LTC

Definitions: Boundary, Criticality, Duty Cycle, and Service Condition

Boundary Definition

The boundary of a Substation transformer with an LTC used for the purpose of this database, is defined from bushing to bushing, including:

- Transformer core and windings
- Pumps
- Controls
- Fans
- Heat exchanger
- Load tap changers
- Surge and lightning arrestors
- Pressure relief valves
- Sensors, monitors, alarms, and current transformers.

Excluded from this treatment were: protective, timing, and control relays, line isolation breakers, conductors, low voltage motor starters and contactors, and fire suppression equipment. The relays can be found by referring to the PM Basis for Relays - Control, Timing, or Protective, and the motor components can be found by referring to Motors - Low Voltage.

Functional Importance

Critical

Required for critical customer support, or risk significant for nuclear plant supply.

Minor

Of some economic importance, e.g. for any of the following reasons: supports non-critical customers, has a high potential to cause the failure of other critical or economically important equipment.

If the failure does not support critical customers and also is not economically important, this would correspond to Run-To-Failure, but these cases are excluded from the Template.

Duty Cycle

High

Frequently cycled load tap changer.

Low

Continuous operation with relatively infrequent load tap operation.

Service Condition

Severe

High or excessive humidity, excessive temperatures (high or low) or temperature variations, excessive environmental conditions (e.g. salt, corrosive, airborne contaminants), loaded near to or above nameplate capacity.

Mild

Absence of the above conditions.

Failure Locations, Degradation Mechanisms, and Discovery/ Prevention Opportunities

Table 3-1
Failure Locations, Degradation Mechanisms, and Discovery/ Prevention Opportunities for Transformer - Substation - LTC

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Transformer Oil (mineral)	Loss of dielectric strength	Contamination (particulate, water)	R	Oil dielectric test Oil quality test Oil power factor testing
Transformer Oil (mineral)	Dissolved gasses	Arcing, sparking, partial discharge, overheating, loose core grounds	R	DGA Partial discharge detection
Windings	Insulation breakdown	Heat from overloading or loss of cooling	W5_7	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test Thermography
Windings	Insulation breakdown	Arcing, sparking, partial discharge, overheating	R	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test
Windings	Insulation breakdown	Aging: normal operation	UW40	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Windings	Insulation breakdown	Voltage surges	R	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test
Windings	Insulation breakdown	Degraded oil, acid and moisture	W10_15	Power factor Turns ratio test DGA Oil quality Furan analysis Partial discharge testing Winding resistance test
Windings	Loose Wedges and Blocking	Shrinkage	UW20_30	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test
Core	Loose	Assembly or shipping error	R	DGA Vibration Sound level
Core	Loose	Vibration	UW40	DGA Vibration Sound level
Core	Loss of core ground	Assembly or shipping error	R	Core ground testing
Core	Loss of core ground	Vibration	UW40	Core ground testing
Core	Multiple core grounds	Assembly or shipping error	R	DGA, Core ground testing
Core	Shorted laminations	Over excitation or arcing	R	DGA
Core	Shorted laminations	Poor manufacturing	R	DGA

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Core	Shorted laminations	Shipping or handling error	R	DGA
Gaskets	Leakage	Aging from thermal cycling and stray eddy currents	UW20	Inspection
Gaskets	Leakage	Improper assembly	R	Inspection
Tank	Sludging/oxidation	Water/oxygen in-leak	R	Oil quality test
Oil Filled Bushings	Leakage	O-ring failure	UW15	Inspection
Oil Filled Bushings	Leakage	Over-temperature from high internal resistance	R	Inspection
Oil Filled Bushings	Leakage	Chipped or cracked porcelain	R	Inspection
Oil Filled Bushings	Leakage	Improper maintenance techniques	R	Inspection
Oil Filled Bushings	External contamination	Dirt, salt, environmental conditions	UW5	Monitor a spare bushing Thermography Ultrasonic testing Corona Inspection
Oil Filled Bushings	Loss of BIL	Internal contamination	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Operation above rating	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Low oil level	R	Power factor test Capacitance test Inspection
Oil Filled Bushings	Loss of BIL	Voltage surges (e.g. lightning strikes)	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Manufacturing techniques	R	Power factor test Capacitance test

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Oil Filled Bushings	Loss of BIL	Improper maintenance	R	Power factor test Capacitance test Inspection
Oil Filled Bushings	Loss of BIL	Chipped or cracked porcelain	R	Power factor test Capacitance test Inspection
Solid Bushings	Loss of BIL	Chipped or cracked porcelain	R	Inspection Power factor test
Solid Bushings	Loss of BIL	External contamination, dirt	UW5	Inspection Power factor test
Lightning/Surge Arrestors	Open circuit	Aging	R	Watts loss test Leakage current
Load Tap Changer	Damaged or misaligned contacts	Normal wear and binding of mechanism	UW3_6	Inspection Motor current monitoring DGA Thermography Acoustic monitoring
Load Tap Changer	Damaged or misaligned contacts	Improper maintenance	R	Inspection Motor current monitoring DGA Thermography Acoustic monitoring
Load Tap Changer	Leaking: pipes, tubing, fittings, gaskets, and valves	Age, normal wear	UW20	Inspection
Load Tap Changer	Motor operator failure	Bound linkages	R	Operation counter Inspection
Load Tap Changer	Motor operator failure	Exceeding duty cycle	R	Operation counter Inspection
Fin and Tube Coolers	Airside fouling	Dirt, salt	UW10_15	Inspection Oil temperature monitoring
Fin and Tube Coolers	Airside fouling	Debris	R	Inspection Oil temperature monitoring

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Fin and Tube Coolers	Loss of heat transfer	Low oil level	R	Inspection Oil temperature monitoring Thermography
Fin and Tube Coolers	Leaks: tube to header	Thermal expansion	UW40	Inspection
Fin and Tube Coolers	Leaks: tube to header	Vibration	UW40	Inspection
Fin and Tube Coolers	Leaks: tube to header	Manufacturing defect	R	Inspection
Fin and Tube Coolers	Coupling or flange leaks	Improper installation	R	Inspection
Fin and Tube Coolers	Coupling or flange leaks	Improper design	R	Inspection
Fans	Motor bearing wear	Normal use	UW7_10	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication
Fans	Motor bearing wear	Failure of lubricant	W5_7	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication
Fans	Motor bearing wear	Fan blade imbalance	R	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication
Fans	Degraded winding insulation	Aging, temperature	UW40	Insulation resistance
Fans	Degraded winding insulation	Water ingress at connections	R	Insulation resistance
Fans	Fan blade cracks	Fatigue	W40	Inspection
Fans	Fan blade cracks	Corrosion	W40	Inspection

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Fans	Fan blade cracks	Imbalance	R	Inspection
Fans	Fan blade cracks	Improper maintenance	R	Inspection
Fans	Motor power cable deterioration	Sunlight	UW10_15	Inspection
Pump	Impeller and volute wear	Normal use	UW40	Vibration monitoring Motor current Acoustic monitoring Ferrography Flow indication
Pump Motor	Winding insulation failure	Aging, temperature	UW40	Insulation resistance
Pump Motor	Winding insulation failure	Water ingress at connections	R	Insulation resistance
Pump Motor	Motor bearing wear	Normal use	UW7_10	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication
Pump Motor	Motor power cable deterioration	Sunlight	UW10_15	Inspection
Valves	Stem leaks	Normal use, packing shrinkage	UW20_40	Inspection
Valves	Closed valve	Maintenance error	R	Inspection, thermography
Sudden Pressure Relay	Misoperation	Normal use (switch, spring, and diaphragm)	UW40	Functional test Replacement
Sudden Pressure Relay	Misoperation	Loose because of vibration	R	Functional test Replacement
Sudden Pressure Relay	Misoperation	Installation error	R	Functional test Replacement
Level Alarms	Misoperation	Installation or maintenance error	R	Functional test

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Level Alarms	Misoperation	Binding or broken linkage	R	Functional test
Temperature Gauges	Drift	Drift	UW10_20	Thermography, Calibration
Desiccant	Outlet breather valve fails to seal	Aging (Normal use, environmental contamination)	UW40	DGA
Desiccant	Diminished capability	Moisture	UW3_6	Inspection
Gas Blanket Systems	Regulator failure	Drift	UW20	Inspection Alarm
Gas Blanket Systems	Leaking: pipes, tubing, fittings, gaskets, and valves	Aging	UW20	Inspection Alarm
Gas Blanket Systems	Leaking: pipes, tubing, fittings, gaskets, and valves	Vibration	R	Inspection Alarm
Pressure Relief Valve	Faulty valve	Aging, weak spring	UW40	Inspection Alarm
Electrical Connections	Corroded/ high resistance	Dissimilar metals, environment	R	Inspection Thermography
Electrical Connections	Loose/ high resistance	Thermal cycling	R	Inspection Thermography
Fans	Deteriorated motor mounts	Elastomer aging, vibration, mounting hardware rust	UW20	Inspection
Gas Blanket Systems	Empty gas bottle	Personnel error	R	Inspection Alarm
Lightning/Surge Arrestors	Shorted	Aging, thermal runaway	UW40	Watts loss test Leakage current
Load Tap Changer	Coking	Duty cycle, degraded oil, high resistance contacts	UW1_3	Inspection Motor current monitoring DGA Thermography Acoustic monitoring
Load Tap Changer	Leaking separator board	Age, heat	UW20	Inspection, DGA of main tank oil

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Oil Filled Bushings	Loss of BIL	Degraded capacitance layers	R	Power factor test Capacitance test
Oil Filled Bushings	External debris	Animal damage	R	Animal guards Inspection
Valves	Closed valve	Vibration	R	Inspection, thermography

Transformer - Substation – No LTC

Definitions: Boundary, Criticality, Duty Cycle, and Service Condition

Boundary Definition

The boundary of a Substation transformer without an LTC used for the purpose of this database, is defined from bushing to bushing, including:

- Transformer core and windings
- Pumps
- Controls
- Fans
- Heat exchanger
- Surge and lightning arrestors
- Pressure relief valves
- Sensors, monitors, alarms, and current transformers.

Excluded from this treatment were: protective, timing, and control relays, line isolation breakers, conductors, low voltage motor starters and contactors, and fire suppression equipment. The relays can be found by referring to the PM Basis for Relays - Control, Timing, or Protective, and the motor components can be found by referring to Motors - Low Voltage.

Functional Importance

Critical

Required for critical customer support, or risk significant for nuclear plant supply.

Minor

Of some economic importance, e.g. for any of the following reasons: supports non-critical customers, has a high potential to cause the failure of other critical or economically important equipment.

If the failure does not support critical customers and also is not economically important, this would correspond to Run-To-Failure, but these cases are excluded from the Template.

Duty Cycle

High

Frequently cycled.

Low

Continuous operation.

Service Condition

Severe

High or excessive humidity, excessive temperatures (high or low) or temperature variations, excessive environmental conditions (e.g. salt, corrosive, airborne contaminants), loaded near to or above nameplate capacity.

Mild

Absence of the above conditions.

Failure Locations, Degradation Mechanisms, and Discovery/ Prevention Opportunities

Table 3-2
Failure Locations, Degradation Mechanisms, and Discovery/ Prevention Opportunities for Transformer - Substation – No LTC

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Transformer Oil (mineral)	Loss of dielectric strength	Contamination (particulate, water)	R	Oil dielectric test Oil quality test Oil power factor testing
Transformer Oil (mineral)	Dissolved gasses	Arcing, sparking, partial discharge, overheating, loose core grounds	R	DGA Partial discharge detection
Windings	Insulation breakdown	Heat from over-loading or loss of cooling	W5_7	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test Thermography
Windings	Insulation breakdown	Arcing, sparking, partial discharge, overheating	R	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test
Windings	Insulation breakdown	Aging: normal operation	UW40	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Windings	Insulation breakdown	Voltage surges	R	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test
Windings	Insulation breakdown	Degraded oil, acid and moisture	W10_15	Power factor Turns ratio test DGA Oil quality Furan analysis Partial discharge testing Winding resistance test
Windings	Loose Wedges and Blocking	Shrinkage	UW20_30	Power factor Turns ratio test DGA Furan analysis Partial discharge testing Winding resistance test
Core	Loose	Assembly or shipping error	R	DGA Vibration Sound level
Core	Loose	Vibration	UW40	DGA Vibration Sound level
Core	Loss of core ground	Assembly or shipping error	R	Core ground testing
Core	Loss of core ground	Vibration	UW40	Core ground testing
Core	Multiple core grounds	Assembly or shipping error	R	DGA, Core ground testing
Core	Shorted laminations	Over excitation or arcing	R	DGA
Core	Shorted laminations	Poor manufacturing	R	DGA
Core	Shorted laminations	Shipping or handling error	R	DGA

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Gaskets	Leakage	Aging from thermal cycling and stray eddy currents	UW20	Inspection
Gaskets	Leakage	Improper assembly	R	Inspection
Tank	Sludging/oxidation	Water/oxygen in-leak	R	Oil quality test
Oil Filled Bushings	Leakage	O-ring failure	UW15	Inspection
Oil Filled Bushings	Leakage	Over-temperature from high internal resistance	R	Inspection
Oil Filled Bushings	Leakage	Chipped or cracked porcelain	R	Inspection
Oil Filled Bushings	Leakage	Improper maintenance techniques	R	Inspection
Oil Filled Bushings	External contamination	Dirt, salt, environmental conditions	UW5	Monitor a spare bushing Thermography Ultrasonic testing Corona Inspection
Oil Filled Bushings	Loss of BIL	Internal contamination	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Operation above rating	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Low oil level	R	Power factor test Capacitance test Inspection
Oil Filled Bushings	Loss of BIL	Voltage surges (e.g. lightning strikes)	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Manufacturing techniques	R	Power factor test Capacitance test
Oil Filled Bushings	Loss of BIL	Improper maintenance	R	Power factor test Capacitance test Inspection

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Oil Filled Bushings	Loss of BIL	Chipped or cracked porcelain	R	Power factor test Capacitance test Inspection
Solid Bushings	Loss of BIL	Chipped or cracked porcelain	R	Inspection Power factor test
Solid Bushings	Loss of BIL	External contamination, dirt	UW5	Inspection Power factor test
Lightning/Surge Arrestors	Open circuit	Aging	R	Watts loss test Leakage current
No Load Tap Changer	Damaged or misaligned contacts	High resistance contact	R	Resistance test DGA
Fin and Tube Coolers	Airside fouling	Dirt, salt	UW10_15	Inspection Oil temperature monitoring
Fin and Tube Coolers	Airside fouling	Debris	R	Inspection Oil temperature monitoring
Fin and Tube Coolers	Loss of heat transfer	Low oil level	R	Inspection Oil temperature monitoring Thermography
Fin and Tube Coolers	Leaks: tube to header	Thermal expansion	UW40	Inspection
Fin and Tube Coolers	Leaks: tube to header	Vibration	UW40	Inspection
Fin and Tube Coolers	Leaks: tube to header	Manufacturing defect	R	Inspection
Fin and Tube Coolers	Coupling or flange leaks	Improper installation	R	Inspection
Fin and Tube Coolers	Coupling or flange leaks	Improper design	R	Inspection
Fans	Motor bearing wear	Normal use	UW7_10	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Fans	Motor bearing wear	Failure of lubricant	W5_7	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication
Fans	Motor bearing wear	Fan blade imbalance	R	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication
Fans	Degraded winding insulation	Aging, temperature	UW40	Insulation resistance
Fans	Degraded winding insulation	Water ingress at connections	R	Insulation resistance
Fans	Fan blade cracks	Fatigue	W40	Inspection
Fans	Fan blade cracks	Corrosion	W40	Inspection
Fans	Fan blade cracks	Imbalance	R	Inspection
Fans	Fan blade cracks	Improper maintenance	R	Inspection
Fans	Motor power cable deterioration	Sunlight	UW10_15	Inspection
Pump	Impeller and volute wear	Normal use	UW40	Vibration monitoring Motor current Acoustic monitoring Ferrography Flow indication
Pump Motor	Winding insulation failure	Aging, temperature	UW40	Insulation resistance
Pump Motor	Winding insulation failure	Water ingress at connections	R	Insulation resistance
Pump Motor	Motor bearing wear	Normal use	UW7_10	Vibration monitoring Motor current monitoring Thermography Acoustics monitoring Lubrication

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Pump Motor	Motor power cable deterioration	Sunlight	UW10_15	Inspection
Valves	Stem leaks	Normal use, packing shrinkage	UW20_40	Inspection
Valves	Closed valve	Maintenance error	R	Inspection, thermography
Sudden Pressure Relay	Misoperation	Normal use (switch, spring, and diaphragm)	UW40	Functional test Replacement
Sudden Pressure Relay	Misoperation	Loose because of vibration	R	Functional test Replacement
Sudden Pressure Relay	Misoperation	Installation error	R	Functional test Replacement
Level Alarms	Misoperation	Installation or maintenance error	R	Functional test
Level Alarms	Misoperation	Binding or broken linkage	R	Functional test
Temperature Gauges	Drift	Drift	UW10_20	Thermography, Calibration
Desiccant	Outlet breather valve fails to seal	Aging (Normal use, environmental contamination)	UW40	DGA
Desiccant	Diminished capability	Moisture	UW3_6	Inspection
Gas Blanket Systems	Regulator failure	Drift	UW20	Inspection Alarm
Gas Blanket Systems	Leaking: pipes, tubing, fittings, gaskets, and valves	Aging	UW20	Inspection Alarm
Gas Blanket Systems	Leaking: pipes, tubing, fittings, gaskets, and valves	Vibration	R	Inspection Alarm
Pressure Relief Valve	Faulty valve	Aging, weak spring	UW40	Inspection Alarm
Electrical Connections	Corroded/ high resistance	Dissimilar metals, environment	R	Inspection Thermography

Failure Location	Degradation Mechanism	Degradation Influence	Time Code	Discovery/ Prevention Opportunity
Electrical Connections	Loose/ high resistance	Thermal cycling	R	Inspection Thermography
Fans	Deteriorated motor mounts	Elastomer aging, vibration, mounting hardware rust	UW20	Inspection
Gas Blanket Systems	Empty gas bottle	Personnel error	R	Inspection Alarm
Lightning/Surge Arrestors	Shorted	Aging, thermal runaway	UW40	Watts loss test Leakage current
Oil Filled Bushings	Loss of BIL	Degraded capacitance layers	R	Power factor test Capacitance test
Oil Filled Bushings	External debris	Animal damage	R	Animal guards Inspection
Valves	Closed valve	Vibration	R	Inspection, thermography

4

RECOMMENDATIONS FOR FURTHER WORK

This report provides preliminary data that can be used with EPRI's *Transformer Asset Management and Testing Model* (1012504) and the companion report *Transformer Asset Management and Testing Methodology* (1012505) to solve the problem of managing a population of substation transformers. It follows several prior reports addressing the development of equipment failure data to support this kind of analysis (EPRI 1008560, 1008561, 1010886, 1012498). Building on that general framework, this report addresses several specific aspects of the problem as it relates to substation transformers: definition of transformer condition states, failure rates, adjustment of failure rates to account for equipment condition, maintenance policies and stressors, condition evolution, test protocols and their accuracy. The experience reported here suggests several additional lines of research with the aim of improving the applicability of the methodology to transformer management:

- Expert Elicitation of Key Parameters
- Data Analysis
- Asset Management Policies

Expert Elicitation of Key Parameters

The decision framework described in this report relies heavily on a number of parameters for which the judgment of experts is currently the best source. These parameters include:

- the differential effects on the hazard rates of the following factors:
- condition states of the transformer
- environmental and operating stressors
- the proportion of the transformer population in each condition state as a function of age
- the accuracy of test protocols in revealing the true condition of the transformer

Essentially, at present, statistical data analysis supports estimating the basic hazard functions; the remainder of the parameters primarily have been estimated by experts.

In the long-run, one needs to calibrate the parameters derived from expert judgment to actual statistical data to the extent possible. These parameters represent the collective, informed judgment of the experts on the panel, but that information needs to be validated by comparing them with empirically derived estimates using actual field and laboratory data. Experience with PM Basis database, reported in EPRI report 1009633, has generally shown reasonable agreement between expert judgment and empirical estimates of failure rates, and it is expected that this experience will also hold true for transformers. The issues involved with calibrating the equipment failure model parallel those for data analysis generally, which are discussed in the next section.

Furthermore, with systematic efforts across the industry, it should be possible in the future to collect data to validate the expert judgments with statistical analysis. Such efforts are already underway with the EPRI Cable Testing Network (ECTN). In these kinds of collaborative efforts, the decision framework discussed in the report can serve to guide the design of the data collection. The framework defines the parameters of importance in transformer asset management decisions. The economic model can also be used, through sensitivity analysis, to identify the parameters that have the greatest impact on the decisions; these parameters should be the primary focus of the data collection effort. Further developments needed for successful industry-wide data analysis include:

- standardizing the definitions of condition states, failure codes, and other dimensions to insure consistent measurement across multiple companies
- establishing data collection procedures utilizing standardized definitions
- calibrating test protocols and developing causal relationships between test outcomes and transformer condition
- implementing long-term data collection among a collaborative group of utilities
- conducting on-going failure cause analysis of selected equipment recovered form the field
- undertaking statistical analysis of the data and comparing with the results of expert judgment

Data Analysis

Ideally, the critical parameters of the decision model, particularly the hazard rates, should be determined empirically using actual data on transformer maintenance. In previous work, some of the issues encountered in data analysis include noisiness of the data and the consequent difficulty in distinguishing hazard rates among the various condition states. There are additional issues that also need to be addressed.

Assembling a dataset for analysis

The first set of issues relates to assembling a dataset for analysis. One of the key design decisions in setting up a decision model is the definition of the state, and one of the key limitations on the state definition is the availability of data. For instance, if the state includes information on various degraded conditions, such as the presence of corroded terminals, then data on degraded conditions is needed in order to estimate different hazard rates for different conditions. Similarly, if the state includes information on what prior maintenance a transformer has received, then data on prior maintenance is needed in order to estimate different hazard rates for different maintenance histories. Without such data, meaningful distinctions in the transformer management policy cannot be made based on transformer condition or prior treatments.

In the short run, the decision model a particular utility can use may depend on what data it already has assembled. However, in the longer run, a utility can specify the data it wants to collect and can develop systems and processes for collecting it. In fact, condition assessment studies are frequently a priority need as a utility adopts an asset management philosophy. Thus, the specification of the decision model can provide significant guidance to the data collection by indicating what data is needed to support it. Furthermore, testing the sensitivity of the decision model for variations in the parameters can provide guidance on the relative importance of collecting various kinds of data and on the required accuracy of the estimates.

Does the dataset reflect actual transformer failure experience?

The second set of issues relates to determining the extent to which the dataset reflects actual transformer failure experience. In particular, if the dataset does not capture certain kinds of failures, then there may be biases in the hazard rate estimates or there may be important aspects of transformer condition that are not represented in the state. One issue is completeness of the data, such that all failures of the inventory of transformers are counted. Another issue is whether the effects of transformer maintenance have been properly accounted for in the dataset.

Validating the hazard rate

A third set of issues relates to validating the estimated hazard rate found using the methods presented in this report. The hazard rate represents a prediction about future failures. It would be very valuable for a utility to validate the prediction by tracking the behavior of the transformer inventory. Further, if the equipment failure model is available, it can be used to predict overall failure rates that may or may not be consistent with the hazard function. Using the equipment failure model to predict overall transformer failure rates entails a bottom-up process of aggregating failure rates from many disparate mechanisms. If the two formulations do not agree, a utility is faced with the task of “debugging” the equipment failure model to determine which of the component degradation mechanisms may be at fault. One way to validate the equipment failure model is to track more detailed information on the condition of transformers in the population over time. Many utilities do not keep such information currently; however, as discussed below, as utilities move toward condition-based maintenance of their equipment, the necessary systems and processes for collecting and tracking equipment condition will be put in place. The equipment failure models will play an importance role in defining what condition information needs to be tracked.

What level of accuracy is necessary to support the decision models?

A fourth set of issues relates to determining the level of accuracy of the hazard rate estimates necessary to support the decision models. Experience has shown that the decisions generated by policy models of the type discussed in the report may not be particularly sensitive to the precision of the failure rate estimates. For example, in the piecewise linear hazard rate model, it may be sufficient to estimate the steady-state hazard rates within, say, an order of magnitude and the start of the burn-out period within, say, five years. Sensitivity analysis of a similar decision model for underground cable replacement, discussed in the EPRI report Guidelines for Intelligent Asset Replacement (1002086), indicates that the most sensitive parameters for those decisions are the steady-state failure rate and the rate of failure acceleration due to prior failures; the time of onset and rate of burn-out are much less sensitive parameters. Performing a sensitivity analysis of a transformer decision model, by varying the input parameters and observing the changes in the decisions, is an essential step for determining where to focus efforts to improve the parameter estimates.

Condition-Based Asset Management Policies

Further consideration of the analytical framework discussed in this report suggests that utilities can enhance their management policies by shifting transformer management from time-based to condition-based policies.

The decision model discussed in EPRI Report 1012505 uses an analytical framework that has a general capability to develop management policies base on transformer condition. The decision framework represents the decisions regarding transformer management as depending on the transformer state, and the state definition explicitly represents the condition of the transformer. However, the shift from a time-based to a condition-based management strategy represents more than formulation of a model; it has profound implications for the maintenance process used by a utility. In particular, it affects the underlying information systems, maintenance management procedures, and crew training and utilization used by the utility. While a complete discussion of these implications is beyond the scope of this report, several observations are in order.

First, using a condition-based management policy requires that information about transformer condition be routinely collected and used in dispatching maintenance projects. The utility needs to establish standardized condition codes, capture condition assessments made by field crews, maintain records of test outcomes over time, track condition deterioration over time, and utilize condition information in deciding when and how to maintain the transformer inventory. The costs of developing the information systems and gathering the data must be considered in the decision to adopt condition-based management.

As discussed in the companion report 1012505, the decision model establishes what information on transformer condition needs to be collected and how it will be used. Furthermore, an equipment failure model provides a framework for condition coding by specifying the important degradation mechanisms and the activities that detect them. Thus, the methodology discussed in this report provides a basis for moving from time-based to condition-based management policies.

Second, condition-based management changes maintenance management. At a macro level, condition-based management may lead to different inspection/testing/maintenance intervals for transformer with different service conditions or environmental stressors. For instance, units in different locations might be maintained on different schedules because their deterioration rates differ. At a micro level, transformers will not have certain maintenance procedures performed unless the test outcomes indicate certain levels of deterioration. Transformer inspections without maintenance might be done more frequently in order to detect the need for maintenance before deterioration proceeds beyond the level at which maintenance is required. Transformer testing and testing accuracy may become more important factors in maintenance decisions. Again, the decision models discussed in this report play a significant role, not only in determining what maintenance decisions to make based on transformer condition, but also in testing whether a condition-based strategy makes sense from an economic and reliability perspective.

Third, implementing a condition-based transformer management policy will require providing specific guidance to the field crews as to what maintenance actions should be undertaken based on transformer condition. One needs to recognize that a policy based on an index of transformer health may be difficult to implement if that index is not readily observable in the field. A further concern is that experienced field crews may not readily accept treatment policies based on unfamiliar methods of assessing transformer condition. These issues imply that implementing a condition-based management policy will require revising a utility's maintenance standards, maintenance actions, and testing protocols and retraining field crews to conform to those revisions. The costs of doing so must be considered in making the decision to adopt condition-based management.

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