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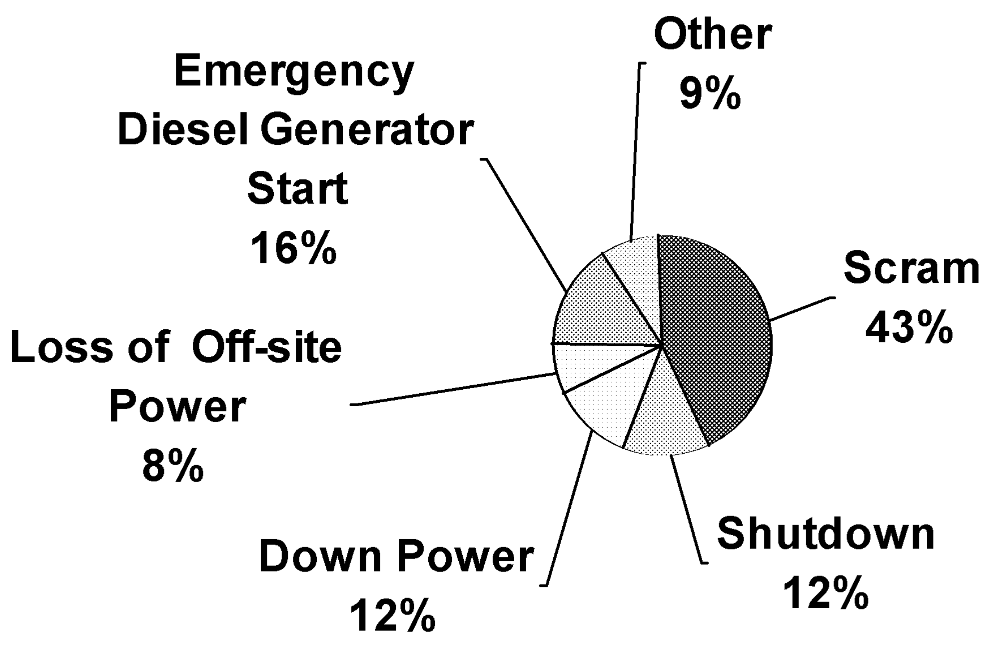
Life Cycle Management Planning Sourcebooks

Volume 4: Large Power Transformers

Technical Report



Consequences of Main Transformer Events

Life Cycle Management Planning Sourcebooks

Volume 4: Large Power Transformers

1007422

Final Report, March 2003

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REPORT SUMMARY

EPRI is producing a series of "Life Cycle Management Planning Sourcebooks," each containing a compilation of industry experience information and data on aging degradation and historical performance for a specific type of system, structure, or component (SSC). This sourcebook provides information and guidance for implementing cost-effective life cycle management (LCM) planning for large transformers.

Background
As explained in the *LCM Sourcebook Overview Report* (1003058), the industry cost for producing LCM plans for the many important SSCs in operating plants can be reduced if LCM planners have an LCM sourcebook of generic industry performance data for each SSC they address. The general objective of EPRI's LCM sourcebook effort is to provide system engineers with generic information, data, and guidance they can use to generate long-term equipment reliability plans for plant-specific SSCs (aging and obsolescence management plans optimized in terms of plant performance and financial risk). The equipment reliability plan or "LCM plan" for a plant SSC combines industry experience and plant-specific performance data to provide an optimum maintenance plan, schedule, and cost profile throughout the plant's remaining operating life.

Objective
To provide plant engineers (or their expert consultants) with a compilation of the generic information, data, and guidance typically needed to produce a plant-specific LCM plan for large transformers.

Approach
Experts in the maintenance and aging management of large transformer systems followed the LCM process developed in EPRI's *LCM Implementation Demonstration Project* (1000806). The scope of the physical system and of component types included in the study was defined. Information and data on historical industry performance of selected types of large transformers within this scope were compiled. EPRI LCM utility advisors reviewed the sourcebook prior to its publication.

Results

This sourcebook contains information on large transformers such as Generator Step-Up (GSU), Unit Auxiliary Transformer (UAT), and Startup Auxiliary or Reserve Auxiliary Transformers (RATs/SATs). It also contains information on transformer accessories and monitoring devices for transformer protection and performance. Information includes performance monitoring issues, component aging mechanisms, aging management maintenance activities, equipment upgrades, and replacements. Based on this information, alternative LCM plan strategy guidance has been developed, along with recommendations. The plan strategy guidance provides information for implementing cost-effective LCM planning for large transformers. The sourcebook includes an extensive list of references, many of which are EPRI reports related to the maintenance and reliability of large power transformers.

EPRI Perspective

Using this report as a starting point should enable the preparation of plant-specific plans for large transformers with substantially less effort and cost than if planners had to start from scratch. The sourcebook captures both industry experience and the expertise of the sourcebook authors. Using this sourcebook, plant engineers need only add plant-specific data and information to complete an economic evaluation and LCM plan for the plant's large transformers. EPRI plans to sponsor additional LCM sourcebooks for as many important SSC types as may be useful to operating plants (perhaps 30 to 40) and as are allowed by industry-wide resources. The process of using sourcebooks as an aid in preparing LCM plans will improve as the industry gains experience. EPRI welcomes constructive feedback from users and plans to incorporate lessons learned in future revisions of LCM sourcebooks.

Keywords

Life cycle management
Nuclear asset management
System reliability
Component reliability
Large transformer

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MANAGEMENT SUMMARY

This Life Cycle Management (LCM) Planning Sourcebook for large transformers will help guide plant engineers or expert consultants in preparing a life cycle management plan (long-term reliability plan) for large transformers at their plants. The generic information and guidance presented in this sourcebook is expected to help plant engineers focus on areas where there may be significant opportunities for cost-effective improvements. Use of the sourcebook will reduce the cost of preparing a plant-specific LCM plan by approximately a third compared to starting from scratch.

The sourcebook identifies component aging mechanisms together with the maintenance activities to manage them, as well as obsolescence issues and available management options. It provides hypothetical LCM plan alternatives to serve as starting points for plant-specific applications. Guidance consists mainly of generic industry-wide information and references on large transformers and their components. Guidance is provided on how to build alternative LCM plans that can be considered during long-term planning for the critical components. Depending on the level of detail desired for the plant-specific LCM plan, the generic data in this sourcebook may allow engineers to identify areas where significant cost-effective improvements or reduction in maintenance activity can be realized and where long term planning for emerging obsolescence issues can be developed.

Important reasons for covering large power transformers in a sourcebook are:

- High reliability of large transformers is important to economic plant operation.
- At some plants, inspection and maintenance of large power transformers is not given a high priority.
- Some of the large power transformers and their components may become obsolete in the near future, requiring replacement, substitution, or upgrades, particularly for plants contemplating license renewal or power uprate.
- Increased load on the main transformer due to power uprate and increased electrical loads on the auxiliary transformers have reduced transformer life.

Large transformer industry reliability issues addressed by this study are:

- Monitoring of the oil and insulation quality is paramount to preserving the life of a transformer.
- Although transformers are designed and built for 30 to 40 year service life, operating and maintenance practices can affect their service life span.

The potential alternative LCM plans considered include:

- Implementing diagnostic maintenance, which includes programs such as thermography, oil analysis, etc.
- Establishing/revising Preventive Maintenance (PM)/Predictive Maintenance (PdM) tasks and schedules.
- Establishing refurbishment program.
- Maintaining a spare in the same fashion as the operating transformers.
- Establishing other options for spare transformers on a pre-negotiated basis with vendors or other plants.

2
INTRODUCTION

2.1 Purpose of LCM Sourcebooks

As indicated in the Life Cycle Management (LCM) Sourcebook Overview Report [1], an LCM sourcebook is a compilation of generic information, data, and guidance an engineer typically needs to produce a plant-specific LCM plan for a System, Structure or Component (SSC). This sourcebook will enable plant engineers or outside experts to develop a plant-specific LCM plan for large transformers with substantially less effort than if they had to start from scratch. The engineer need only add plant-specific data and information to complete an economic evaluation and LCM plan for large transformers.

It must be recognized that not all generic information in a sourcebook applies to every plant. Some of the data can serve for comparison or benchmarking when preparing plant-specific LCM plans. Other data may show indicators or precursors to problems not yet experienced at a given plant. Therefore, caution and guidance is provided in the plant-specific guidance sections (Sections 5, 8, and 9 of the sourcebook) for the use and application of the generic information. These sections also contain useful tips and lessons-learned from the EPRI LCM Plant Implementation Demonstration Program [2].

2.2 Relationship of Sourcebook to LCM Process

The process steps for LCM planning are described in detail in the EPRI LCM Report [2]. The LCM planning flowchart (Figures 2-1a, b, c of this large transformer sourcebook) is essentially the same as Figure 1-1 of the LCM Sourcebook Overview Report [1]. The chart is segmented into the four elements of the LCM planning process: SSC categorization/selection, technical evaluation, economic evaluation, and implementation. Process step numbering has been maintained consistent with the LCM report.

2.3 Basis for Selection of the Large Transformers for LCM Sourcebook

An LCM Sourcebook for large transformers has been prepared because the component met the following important objectives of the SSC selection process:

- Applicability to both BWRs and PWRs
- Importance to safety risk and regulatory concern
- Importance to power production
- Subjected to significant degradation and obsolescence
- Have a history of chronic maintenance problems

Figure 2–1a
LCM Planning Flowchart – SSC Categorization and Selection

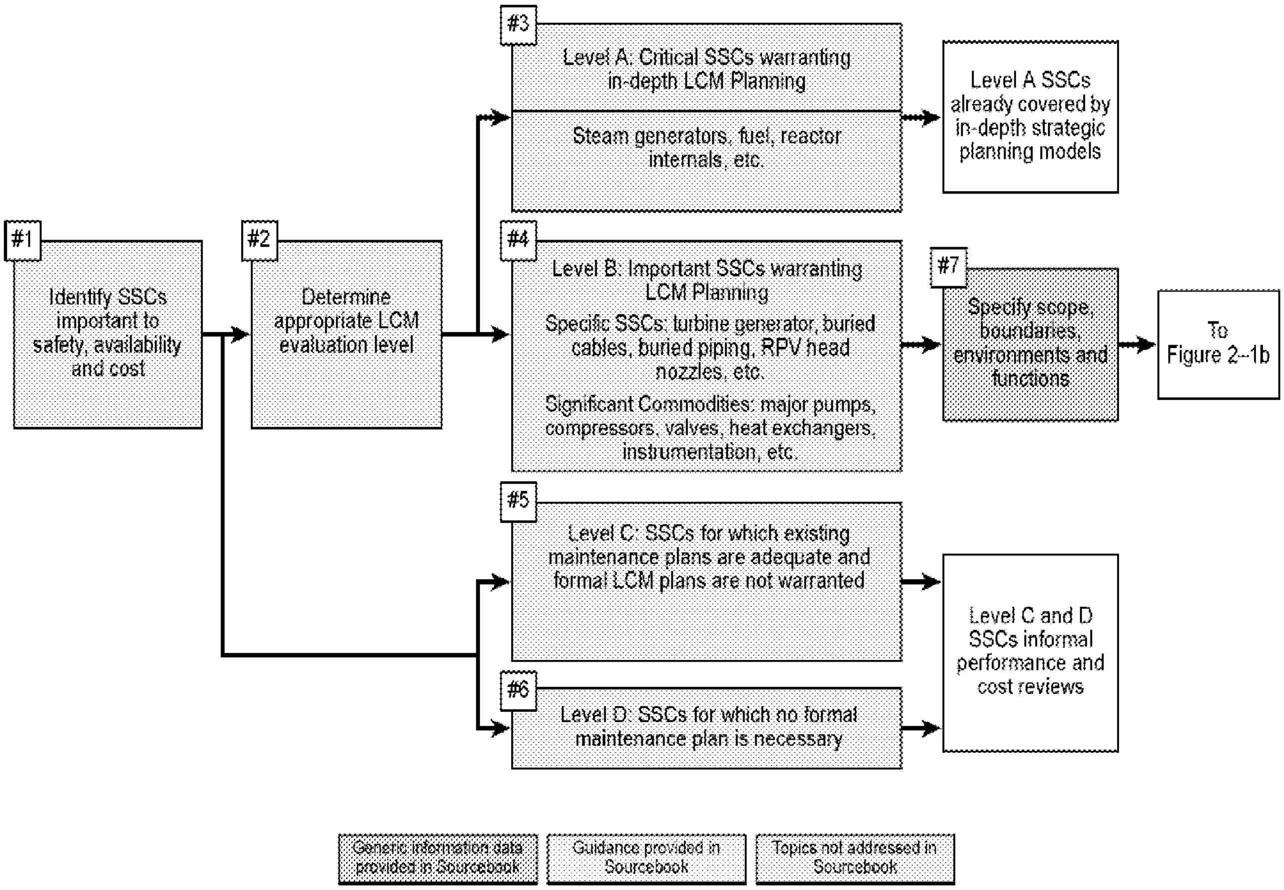

Figure 2-1a
LCM Planning Flowchart – SSC Categorization and Selection

Figure 2–1b
LCM Planning Flowchart – Technical and Economic Evaluation

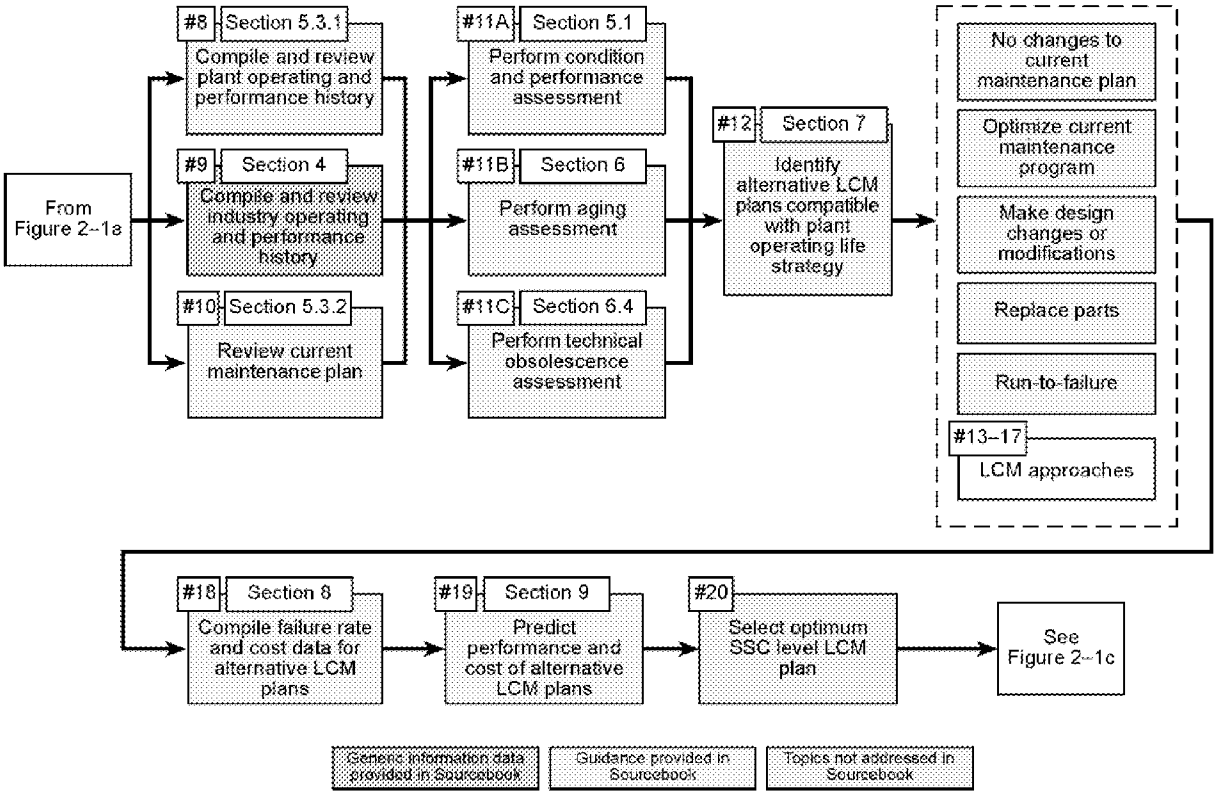

Figure 2-1b
LCM Planning Flowchart – Technical and Economic Evaluation

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Figure 2–1c
LCM Planning Flowchart – Implementation

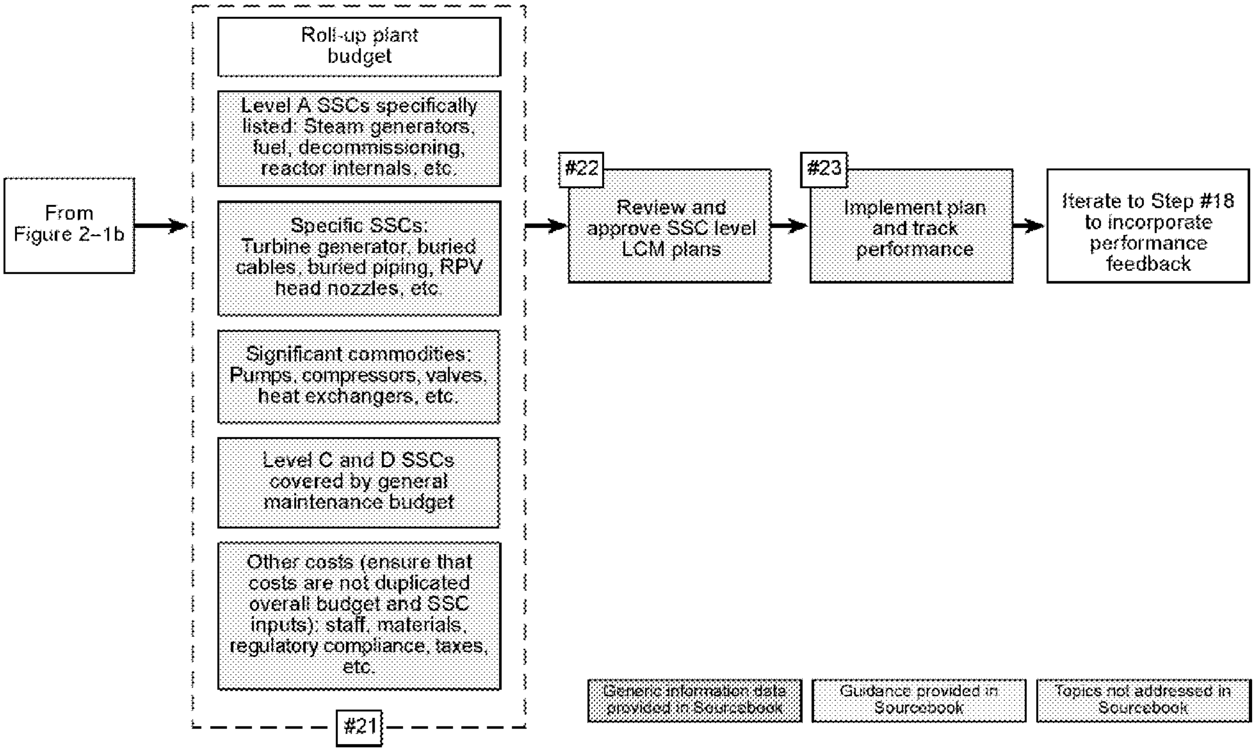

Figure 2-1c
LCM Planning Flowchart – Implementation

3 BASIC INFORMATION ON LARGE TRANSFORMERS

This section addresses step number 7 in Figure 2-1a. Large transformers are used in power plants to connect the main generator to the high-voltage (HV) transmission system. Large transformers are also used to connect the plant and off-site sources to the plant's distribution system for operation of auxiliary equipment at medium and low voltages. The large transformers of particular interest to the power plants range in size from 2.5 MVA to 1500 MVA with a voltage range of 4.16 kV to 765 kV and are typically installed outdoors. The characteristics of large transformers do not depend on whether the plant is a PWR or a BWR, but on the size of the transformer (i.e., MVA rating). Larger MVA range transformers are custom designed to meet the parameters such as voltages, short circuit currents, etc., specified by the plant requirements. This sourcebook will focus on Generator Step-Up (GSU) or Unit Transformers (UT), Unit Auxiliary Transformers (UAT), Startup Auxiliary Transformers (SAT), also called Reserve Auxiliary Transformers (RAT). EPRI's "Power Transformer Application and Maintenance Guide" [5], provides a list of the subject transformers in nuclear plants located in the US and Canada. The list indicates the manufacturers, ratings, and types.

3.1 Safety and Operational Significance

The GSU transformer is used to step-up plant generated voltage (18 to 26 kV) to the required grid voltage (115 to 765 kV). In contrast, the reserve and auxiliary transformers step-down the voltage to the desired plant system voltages (4.16 to 13 kV). The GSU transformers are non-safety-related but the loss of a main transformer could cause scrams, and/or transients, with the resulting loss of power production. The auxiliary transformers are typically non-safety-related, but they are "important to safety" as they supply power to the safety-related buses and also serve as an off-site power source for plant operation and shutdown. These transformers, along with the offsite power system, are designed to meet the nuclear plant general design criteria as stated in the FSAR and Technical Specifications. These transformers are the preferred source of power to supply the safety-related auxiliary buses under accident and post-accident conditions. Safety-related auxiliary buses are essential for safe shutdown or in preventing significant release of radioactive material to the environment. The safety-related buses are supported by diesel backup power; however, the loss of these transformers has major implications for plant safety and causes undesirable challenges to the plant safety systems.

The functions of large transformers are as follows:

- The GSU is used to connect the generator to the high voltage transmission system or to the grid. These are built as three-phase units in one tank or three single-phase units in separate tanks. Failure of the GSU will cause a plant trip.

- The UAT -- also called “normal station service transformer” -- is usually fed from the main generator leads and supplies power to the unit auxiliaries. The UATs supply power to the unit auxiliary equipment (4.16 or 13 kV) buses. Failure of a UAT causes the loss of one power source and may result in a plant trip or reduced power operation.
- The RAT or SAT is used to provide a second source of power for the plant auxiliary equipment from an off-site source. The RAT/SAT provides power to the station equipment when the generating unit is off-line, and serves as a backup power supply when on-line. The RAT/SAT feeds the plant auxiliary equipment through a segregated or non-segregated bus duct. The primary side of this transformer (off-site source) is high voltage in the range of 69 kV to 765 kV. Some plants have on-site auxiliary power supplies (gas-powered combustion turbine generators, auxiliary diesels, etc.), and therefore may not require an RAT or SAT.

Nuclear power plants are required by the NRC to have redundancy for their safety-related auxiliary power buses. UATs, RATs/SATs, and diesel generators feed the safety-related buses. Redundancy is provided to each safety-related bus by one or two UATs served by the generator and one or two SATs served from reserve or an alternate source. This system, with the desired breaker line-up, can bring power from another source to the plant distribution system. Another method is to provide redundancy by the use of a normal and/or maintenance (swing) bus. In this case, all loads are transferred to another bus fed from another source.

3.2 Large Transformer Functions

Large power transformers transmit bulk power for distribution and provide power for plant auxiliary loads. All large US-made transformers are designed, manufactured, and operated in accordance with IEEE/ANSI Standard C57.12.00, “General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers” [24]. The transformers considered in this sourcebook are large units, located outdoors, and typically liquid-cooled. Detailed information on large transformers can be found in textbooks and other publications such as the EPRI Power Plant Electrical Series, Volume 2, [22] “Power Transformers,” and EPRI TR-1002913, “Power Transformer Application and Maintenance Guide” [5].

The generator is connected to the high voltage system through isophase bus ducts and the generator main transformer. The main transformer/GSU usually carries constant load. The primary winding of the GSU is connected by flexible links to the isophase bus duct that connects to the terminals of the generator.

The GSU normally requires no voltage regulating winding since the field of the generator regulates the voltage. The secondary winding of the GSU is high voltage and requires large internal clearances, which means the transformer tank is large. On large generator MVA output, some utilities choose multiple, single-phase transformers or two half-MVA capacity three-phase transformers.

The UAT is tapped off the isophase bus duct to feed the plant auxiliary equipment through a segregated or non-segregated bus duct. The UAT load may vary during startup and shutdown switching operations. The UAT primary and secondary voltages are medium range and the transformer tank is normally smaller with small internal clearances.

A second power supply for plant auxiliary equipment is provided from the preferred power supply (off-site source) though the RAT or SAT. The RAT/SAT provides power to the station equipment when the generating unit is off-line and serves as a backup power supply when the unit is on-line. It feeds the plant auxiliary equipment through a segregated or non-segregated bus duct. The primary side of this transformer (off-site source) is high voltage and requires large internal clearances.

Figure 3-1 is a typical generating station one-line diagram that illustrates the use of large transformers.

3.3 System and Component Boundaries

This LCM sourcebook includes the GSU, RAT, SAT, UAT, and their components. The detail and depth of evaluation for the individual components are commensurate with their importance and reliability.

The following subsections discuss the individual components and their respective functions and importance.

3.3.1 Transformer Components

The principal parts of a transformer include:

- tank and oil preservation
- magnetic core
- windings
- insulation system
- insulating liquid
- accessories

3.3.1.1 Tank and Oil Preservation

The transformer case or tank that houses the core and coil provides mechanical protection for the core and coil assembly and contains transformer cooling oil. Gaskets made of neoprene, cork-nitrile, nitrile, or viton are used throughout the transformer to prevent leakage of oil from pumps, manways, and accessory devices.

Sealed-Tank System. The sealed-tank type has a space above the oil in the transformer tank, which is filled with an inert gas such as nitrogen under pressure. The gas pressure is such that it does not cause high differential pressure between the inside and outside of the tank. The transformer tank and other components are tightly sealed, thereby preventing moisture entering the tank. Transformers utilizing this type of oil preservation system are equipped with a pressure/vacuum bleeder to allow the nitrogen to be expelled if the internal pressure gets too high, and allows outside air to enter if the internal pressure gets too low, thereby protecting the main tank from possible damage.

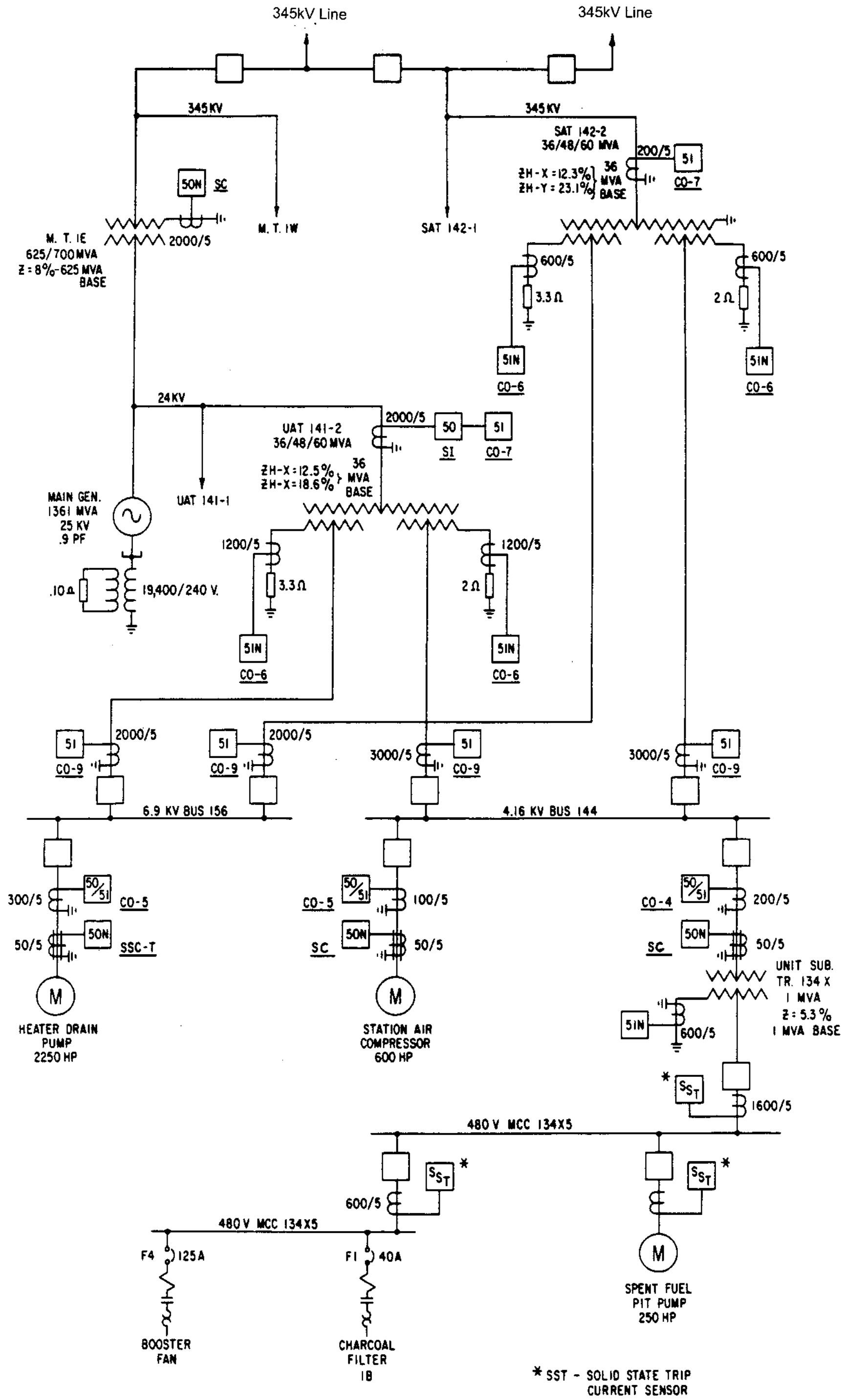

Figure 3-1
Typical Generating Station One-Line Diagram

Inert-Gas-Pressure System. The inert gas system uses a blanket of nitrogen to pressurize the void space above the oil volume to a pressure slightly greater than atmospheric. The nitrogen is supplied from storage bottles located near the transformer; a regulating valve maintains a slight positive pressure on the void space. During periods of expansion, another valve controls the venting of excess gas, thereby preventing over-pressurization. The regulating valves are calibrated to prevent simultaneous venting and charging of gas. Periodically, the gas bottle inventory is verified, and empty bottles are replaced or recharged.

Sealed Conservator System. In the sealed conservator, the entire volume of the tank is kept continually filled with fluid from a surge tank (conservator) mounted above the main tank. As the volume of the fluid decreases or increases, the surge is made up by or exhausted to the conservator tank. The void space (open to atmosphere) and fluid volume in the conservator are separated by a diaphragm (air cell or bladder) which prevents the contamination of the oil by moisture, gases, or other contaminants. The cycling of the air to the bladder may pass through an air dryer filled with desiccant. Oil level in the conservator tank is measured via a float-type level sensor; the main tank is always completely filled.

Free-Breathing Conservator System. This system is identical to the Sealed Conservator System except that there is no diaphragm or bladder. In this system, the surface of the oil in the conservator tank is exposed to the outside air. The cycling of the air in and out of the conservator passes through an air dryer filled with desiccant in order to keep moisture from entering the transformer. Transformers utilizing this system usually have a high oxygen content.

3.3.1.2 Magnetic Core

The core is that part of a transformer in which the alternating magnetic field flows. It provides a low-reluctance path for the flux linking primary and secondary coils. The core is made of a very high grade iron with a small percentage of silicon. The core is formed of thin sheets, and each side of each sheet is coated with an insulating material. The laminating and insulating thin sheets form a high resistance path to the eddy-current. This material prevents currents from circulating in the core with the resultant heat and loss of power.

Core laminations are properly secured by a clamping structure. The whole core assembly is clamped together by steel frames to hold the transformer windings together to withstand mechanical forces generated during normal operation or under fault conditions.

3.3.1.3 Windings

Transformer winding coils are designed and wound around the core according to the transformer ratio, i.e., the number of turns. An individual winding turn may consist of many copper strands that are insulated individually. The entire turn is usually wrapped in paper insulation. A turn usually consists of several individually insulated copper conductor strands. Some turns are constructed from continuously transposed conductor (CTC). The individual strands within the CTC occupy a different position in the turn as it is wound. This system is used to reduce leakage flux and thus has a higher short circuit strength. The windings are constructed by winding the turns over a winding cylinder, which is mounted on a winding mandrel.

Some of the basic types of transformer winding are disk, layer, pancake and helical. A disk winding consists of physically parallel winding sections, which are connected electrically in series. Each section of the winding contains one or more turns. Radial and axial spacers are placed between each section to provide insulation between sections and to allow oil to cool the copper conductors. Radial and axial spacers are also placed between turns of a helical winding for insulation and cooling purposes. Layer windings are composed of complete layers of turns spanning the length of the winding and separated by insulation and axial spacers for cooling. Pancake windings are used on shell-form transformers and are composed of individual rectangular washers stacked together to form the complete winding.

3.3.1.4 Insulation System

The most widely used winding insulation material is paper. When dried and impregnated with good quality oil, electrical grade paper has high dielectric strength. Besides winding insulation, insulating barriers are used between parts of the winding and between windings. As the paper ages, it becomes brittle. Other types of insulation, such as enamels, are used to insulate the copper strands that comprise a winding turn.

3.3.1.5 Insulating Liquid

The primary functions of the insulating oil are to insulate the primary from the secondary windings and ground, and to transfer the heat from the windings to external cooling equipment. The oil used in transformers is a highly refined mineral oil. Oil penetrates the paper insulation and fills the spaces between the core and coils, thus maintaining the properties of paper and other cellulose-based insulation material.

Transformer oil will maintain its maximum dielectric properties if the water content is kept low (the dielectric properties break down with increased water content). Some quantity of water is locked in the transformer cellulose insulation. Although a new transformer has gone through the drying process, insulation such as paper, pressboard, or other material is not water-free. When a new transformer is placed in-service, some of this water comes out of the insulation and mixes with the oil. In addition, moisture may be present in newly refined oil. External moisture from the atmosphere is another source of water.

Failures are minimal if oil and paper are kept dry, the oxygen content is nominal, and the hot-spot temperatures are not above the nameplate ratings.

Particle contamination also reduces the dielectric properties of transformer oil. Additives such as oxidation inhibitors and anti-sludging additives are used in the oil to improve its long-term characteristics

3.3.1.6 Transformer Accessories

Major accessories can contribute to transformer failures if not properly monitored and maintained. Examples of failed accessories that can contribute to transformer failures are bushings, load tap changers, and sudden pressure relays.

Oil Level Indicator. The oil level indicator is used to indicate the level of the insulating oil in liquid-immersed transformers. A common design of indicator uses a pivoted float arm located in the tank and magnetically coupled to a shaft and pointer arrangement outside of the tank, thereby allowing a completely sealed interface. When the position of the float changes, the magnetic coupling is rotated which moves the pointer a proportionate amount. The indicator also includes alarm switches for monitoring functions.

Oil Temperature Indicator. The oil temperature indicator consists of a temperature sensing bulb, indicating device, and a switch. The switch can be used to control fans, pumps, annunciator circuits. The indicator has switches for automatic control of one or two stages of cooling fans and an alarm switch.

Winding Temperature Indicator. For the most common type of winding temperature indicators, a simulated winding temperature is obtained by adding to the top oil temperature a temperature increment that results from the heat produced by a current proportional to the load current flowing through a heating element. Earlier versions of these devices used a physical resistance, located in a well near the top of the tank, to create the additional heat, but new types can do this through software. Electronic devices are also available and provide high accuracy.

Gas Detector Relay. A gas detector relay is used on transformers with a conservator tank. The relay is mounted on top of the transformer and is connected to a gas accumulator with tubing. The gas accumulator is under the top cover of the transformer. Under normal conditions, the gas accumulator is filled with oil. During abnormal conditions in the transformer tank, gases are generated from the deterioration of insulation or decomposition of oil around hot spots. Gases rise to the gas accumulator and the gas relay. If a significant amount of gas is generated, an alarm will be actuated. Another type of gas relay is known as the "Bucholtz relay," and is mounted in the pipe connection between the main tank and the conservator. Accumulations of gas in this relay will signal an alarm or trip the transformer.

Pressure Relief Valve. The tank design pressure (approximately 10 psig) is not sufficient to withstand pressures resulting from large internal faults and therefore, the pressure relief valve is used to relieve the pressure from the tank.

Sudden Pressure Relay (Rapid Pressure Rise Relay). The sudden pressure or fault pressure relay detects sudden pressure transients produced within the transformer tank during operation. If the internal pressure exceeds the safe limits, the relay will activate the tripping scheme to de-energize the transformer.

The sudden pressure relays are usually temperature compensated to allow relatively stable pressurization rate detection in the design ambient temperature range. Sudden pressure relays experience spurious actuations due to age (switch, spring, and diaphragm), vibration, installation error. Such spurious activity can be prevented by periodic functional tests and/or replacement.

Deluge/Fire Protection. Large power transformers can fail from either an internal or external electrical fault that results in over pressure of the tank. In cases where an internal pressure is rapid, the pressure relief device may not be adequate to prevent tank failure. Tank failure may release substantial quantities of insulating liquid and may initiate a fire.

NFPA 70, National Electric Code and NFPA 850, Fire Protection for Fossil Fueled Steam Electric Generating Plants, specify the type of protection required for oil-filled outdoor transformers. Protection includes the following:

- Separation
- Fire Barriers
- Detection and a water spray system
- Containment

Nitrogen Regulation System. The nitrogen regulation system is used to maintain positive pressure of nitrogen gas in the tank from an external gas cylinder. It prevents the oil from coming into direct contact with the surrounding atmosphere.

The gas regulation system consists of the gas cylinder, high and low pressure valves, by-pass valve, pressure bleeder, hoses, alarm contacts and gauges. An alarm is activated when the pressure in the external cylinder drops below 300 psi to warn personnel that a new gas cylinder is needed.

Fans and Radiators. For oil filled transformers, fans and radiators are mounted at various locations around the transformer for cooling. The fans are usually mounted on the radiators. The fans, motors, cables and conduit boxes are of weatherproof design and are suitable for outdoor use. Radiators that are difficult to clean are replaced with coolers having different design fins that do not clog easily and are easier to clean.

Oil Pumps. The oil pump circulates oil from the transformer tank through the oil coolers. The pump is controlled by the winding temperature detector. Bearing failure may occur on the oil pumps and motors.

Tap Changers. Transformers are usually provided with a mechanical switching device to adjust the voltage ratio by means of adding or removing turns from the winding. The change is achieved either manually when the transformer is de-energized, or automatically at load.

De-Energized Tap Changers (DETC). DETCs employ manually-operated switching equipment that changes the turns ratio of the three phases simultaneously and by the same amount. In the case of single-phase transformers, each has its own manually-operated DETC switching device. The DETC switching device is located in the main tank along with the core and coils, and the operating handle is normally located externally on the side of the transformer tank.

The DETC can be operated only when the transformer is de-energized.

Load Tap Changers (LTC). An LTC provides the mechanism to change taps without interruption of the load current. They are often used in distribution substations, but are relatively uncommon in power plants. The LTC compartment is periodically drained and the mechanism is flushed and cleaned, contacts cleaned; and the mechanism adjusted and timed. Internal wiring is sometimes replaced if worn. All gaskets are replaced when the tank is filled with new oil.

Lightning Arresters Lightning arresters play a vital role in the protection of transformers against transient over-voltages resulting from lightning surges and system switching transients. An arrester consists of an air gap in series with a resister element. A common type of arrester in use is the valve type, which consists of one or more gaps in series with a dielectric element serving as a high resistance. Another type is the gapless metal oxide arrester, which consists of a varistor embedded in a ceramic insulator. In an overvoltage condition, the non-linear resistance of the metal oxide reduces and causes excessive voltage to be shunted to ground.

Bushings Bushings provide a means of connection between the internal windings and the external circuit and insulate the primary and secondary windings from the tank. For power transformer high voltage applications, capacitor-type oil filled bushings are standard equipment. A limited number of utilities replace all bushings if the transformer is more than 20 years old or if the power factor is high. Several utilities are replacing a certain type of bushing, which has a record of failures over the years.

Potential Transformers (PTs). Potential transformers are used in the isophase bus duct to reduce the bus voltage to a lower voltage for input to the metering and relaying protective scheme.

Current Transformers (CTs). Current transformers are used to reduce primary current to a proportionally lower value suitable for metering, monitoring and protective schemes.

Control Cabinet. The control cabinet is a weatherproof metal enclosure designed to house all auxiliary devices except those that must be located directly on the transformer. Auxiliary devices in the control cabinet include fuses, breakers, control devices (relays and starters), alarm relays, and associated terminals for wiring and testing.

The control cabinet also houses the AC auxiliary power for pumps and fans, and DC control power. The AC auxiliary power normally has two sources of power and an automatic throwover scheme in case the normal feed fails to allow the emergency source to close in after a momentary interruption.

3.4 Scope and Equipment Covered by the Sourcebook

Large transformers addressed in this sourcebook are the main and the auxiliary transformers. Most of the large transformers used at nuclear power plants were manufactured by Westinghouse, General Electric, McGraw Edison, and ABB. The size range addressed in this sourcebook is 2.5 to 1500 MVA at a high voltage range of 115 to 765 kV and a lower voltage of 4.16 to 13 kV. This sourcebook focuses on the following principal parts and associated accessories considered critical for the continued operation of a transformer.

- Transformer tank and oil preservation
- Magnetic core and windings
- Cooling systems (including, pumps, fans, piping and the associated valves and instrumentation)
- Insulation system

- Electrical connections, terminals
- Lightning arresters
- Taps and tap changers
- Local instrumentation and monitoring equipment
- Current and potential transformers
- Bushings and insulators
- Radiators
- Control panel

The following items, even though important to the function of the transformer, fall under specific plant programs or are considered commodity items and, therefore, are not included in the scope of this sourcebook:

- Transformer foundations
- Structural supports
- Electrical buses and cables
- Missile and fire barriers
- Fire protection
- Transformer protective relays (with the exception of sudden pressure relays)

4 INDUSTRY OPERATING EXPERIENCE AND PERFORMANCE HISTORY

This section addresses step number 9 in the LCM planning flowchart in Figure 2-1b. The information compiled in this section is to be used for a comparison or benchmarking to plant-specific conditions and operating experience. The qualitative data is intended as a checklist of potential conditions affecting plant-specific performance, while the quantitative failure data may provide insight into the potential for plant-specific enhancements and help identify where improvements can best be made.

For example, if the plant-specific component failure rates are much less than what the generic data indicates, one might conclude that the existing maintenance plan is effective and further improvements will be difficult to achieve. On the other hand, equipment performance may be attributed to an excessive maintenance program that would require an overall adjustment of the maintenance practices. Similarly, if the plant-specific component failure rates are substantially higher than the generic failure rates presented here, or if the contribution of large power transformers to lost power production significantly exceeds the generic (PWR or BWR specific) values, equipment replacement or major changes to maintenance practices may be required. Implied here is the notion that if the reliability performance of an SSC falls below a certain level, major maintenance efforts will be required to satisfy Maintenance Rule performance criteria. Ultimately, replacement may be considered if plant operation cannot be sustained.

It should be noted that this section addresses failure and failure data rather than repair practices and data. In general, repair times will be available from plant records and will depend on plant-specific maintenance practices. The mean time to repair (MTTR) will have an impact on the system availability.

4.1 Nuclear Industry Experience

A review of the available industry operating experience and events has been performed to extract the salient information and to present the data such that the plant engineer can assess the plant-specific performance of large transformers.

4.1.1 Qualitative Data

A comprehensive review and evaluation of large transformer problems can be found in SOER 02-3, "Large Power Transformer Reliability" [21]. This document shows that despite the industry's increased attention to transformer maintenance after SOER 90-1, "Ground Faults on AC Electrical Distribution Systems" [20] was issued, transformer events are on a general increase, as shown in Figure 4-1. After SOER 90-1 was issued, many nuclear plants in the early 1990s reviewed their AC distribution system, offsite system, and large power transformer maintenance programs. Documents such as SOER 90-1 emphasized the importance of good preventive maintenance programs and training.

Industry experts have identified the following as the major contributors to transformer problems:

- Because of downsizing measures, not enough experienced personnel are available at the stations to monitor or maintain equipment such as large transformers and therefore, some stations have become too dependent on vendors to perform their monitoring and maintenance.
- Many original equipment manufacturers are no longer in business; therefore, many stations are depending on others for service and technical support.
- Many stations have not retained the special technical knowledge related to high voltage equipment necessary to determine the condition of large power transformers and supporting equipment.

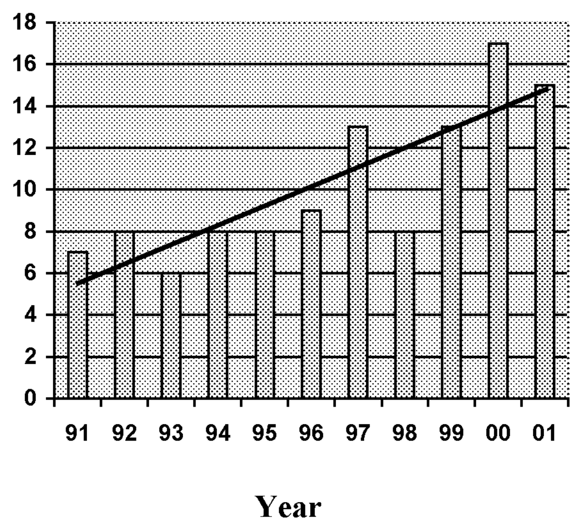

Figure 4-1
Number of Transformer Events Per Year

4.1.2 Quantitative Data

Quantitative failure data for large transformers and their accessories are available from a number of sources. Since 1996, there have been over 70 events associated with large main power transformers, according to SOER 02-3. Data from SOER 02-3 shown in Table 4.1 indicates the number of main power and auxiliary transformers involved in the event, the cause of the event, and the impact on the plant. There were over 30 reactor scrams, numerous plant shutdowns, several power reductions, and diesel challenges associated with the transformer events. Figures 4-2 and 4-3 graphically illustrate the magnitude of the transformer events and their causes.

Table 4-1
Transformer Events 1991 – 2001

	1991-1995	1996-2001	Failure Rate/ Year
Type of Transformer Involved in the Event			
Main station transformer	30	41	0.062063
Unit transformer	4	11	0.013112
Start up transformer	9	24	0.028846
Total Events:	43	76	0.104021
Type of Event that Occurred			
Transformer Trip	22	40	0.054196
Fire/Explosion	7	9	0.013986
Overheat	1	7	0.006993
Oil Leak	1	3	0.003497
Gas accumulation in oil	0	2	0.001748
Internal failure	7	1	0.006993
Others	2	2	0.003497
Most Likely Cause of the Event			
Bushing Failure	5	9	0.012238
Ground fault	3	8	0.009615
Insulation failure/short circuit	3	7	0.008741
External event	4	7	0.009615
Pressure relay failure	1	7	0.006993
Cooling system failure	1	6	0.006119
Maintenance	4	5	0.007867
Engineering	2	4	0.005245
Other	4	7	0.009615
Unknown	16	16	0.027972
Effect of the Event on the Plant			
Automatic Scram	25	25	0.043706
Manual Scram or shutdown	5	4	0.007867
Power reduction	1	7	0.006993

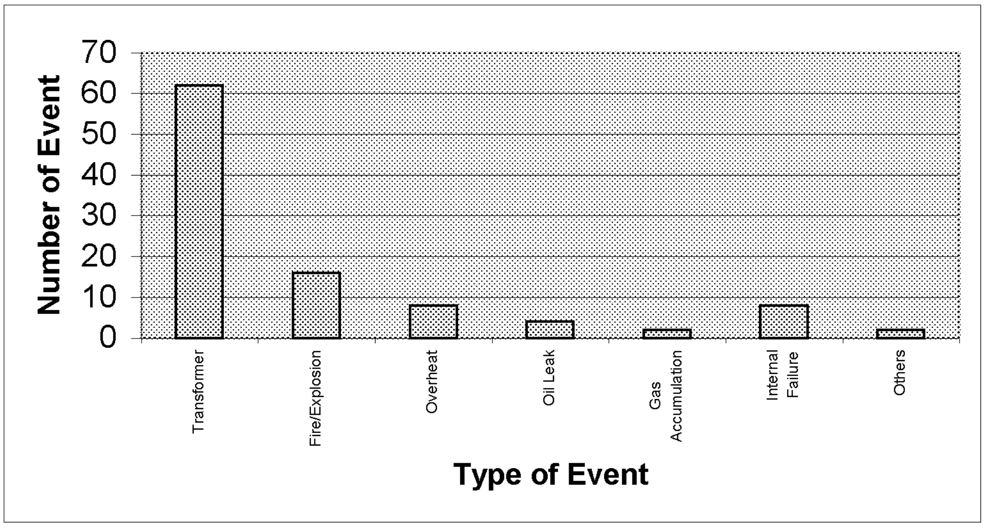

Figure 4-2
Transformer Events

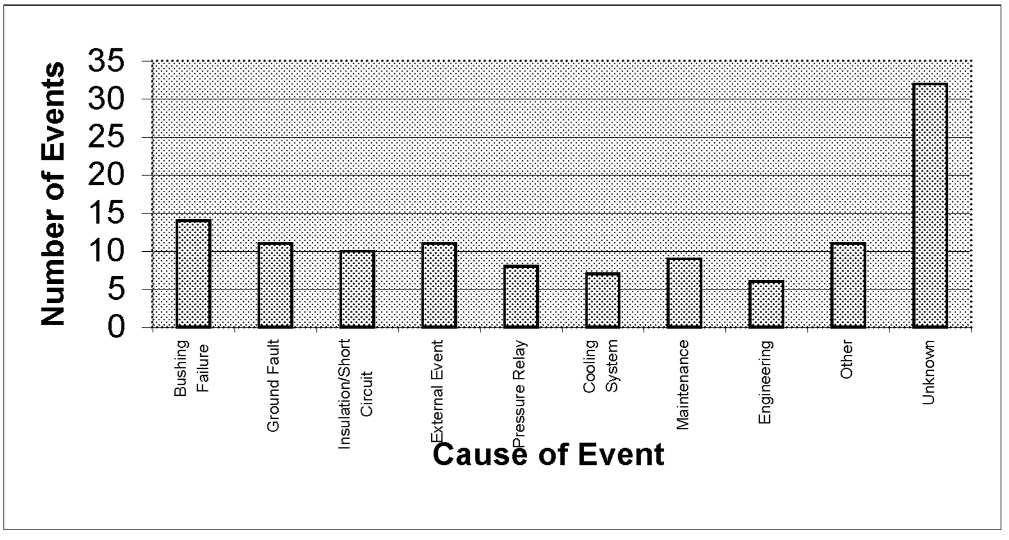

Figure 4-3
Causes of Transformer Events

4.1.2.1 Relative Magnitude of Large Transformer Failure Frequency

INPO SOER 02-3 provides industry benchmarking for large transformer failure data. The failure rate per year is tabulated in Table 4.2. This table was generated by using failures per year divided by the number of plants operating during that year (NUREG 1350, Table 7) [23].

Table 4-2
Failure Rates Calculated from EPIX (SOER 02-3) Data

Year	No. of Failures/Year From SOER 02-3	No. of Units Operating	Failure Rate (per unit per year)
1991	7	111	0.063
1992	8	110	0.073
1993	6	109	0.055
1994	8	109	0.135
1995	8	109	0.073
1996	11	110	0.100
1997	13	104	0.125
1998	14	104	0.135
1999	15	104	0.144
2000	17	104	0.163
2001	15	104	0.144

EPIX and NPRDS are collections of failure data for equipment and systems, as well as engineering and operational issues, taken from US INPO member plants and are available through the INPO website to INPO members. Besides the failure event data, the INPO database also contains reports, which describe the cause of the failure. The results of transformer events, as reported by SOER 02-3, are shown in Figure 4-4.

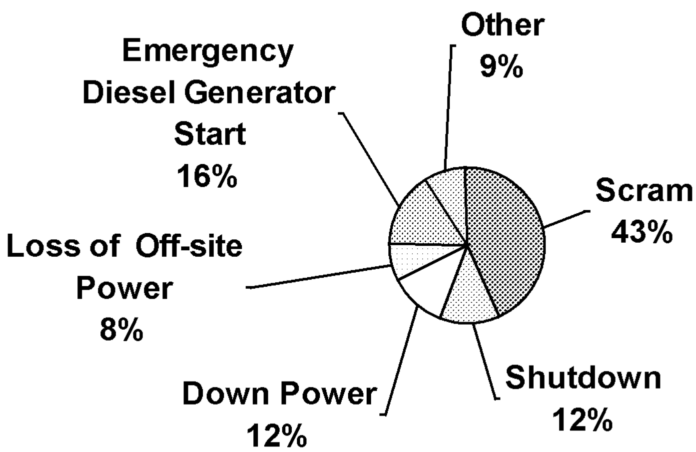

Figure 4-4
Results of Transformer Events

The failure rate trend per year up to 2001 was then projected (Figure 4-5) to predict the failure rate for the next 10 years (year 2011). If continued, this failure trend could increase from a current value of approximately 0.15 to a value of 0.2 by 2011. This factor can be used in Net Present Value (NPV) loss calculations to determine the impact on large transformer failures and economic impact.

The failure rates are calculated assuming the failures presented in Table 4.1 represent all failures that occur in a population of operating plants over a 10-year period, 1991-2001. The resulting failure rate per unit per year is presented in Table 4.2 and the failure rate is graphically show in Figure 4-5.

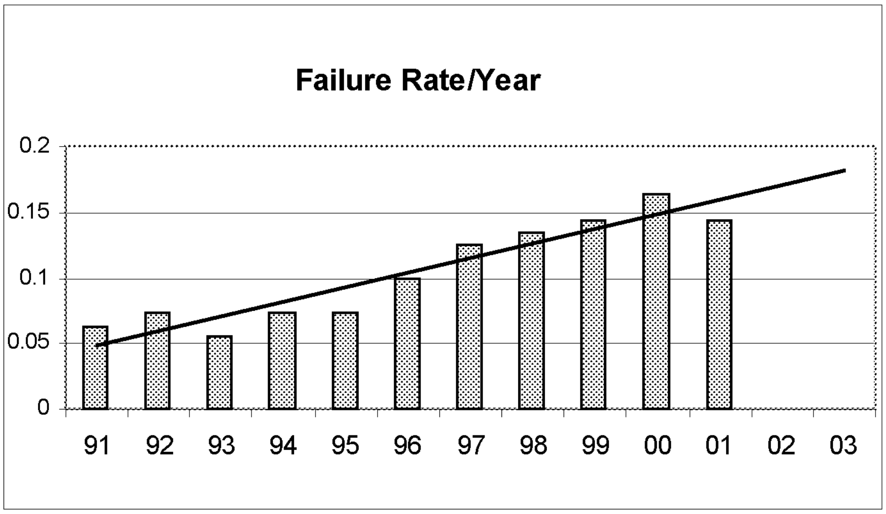

Figure 4-5
Transformer Failure Rate Per Plant and Per Year

4.1.3 Maintenance Rule

Maintenance Rule Section 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Plants," states the following requirements:

> "Each holder of a license to operate a nuclear power plant shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industry-wide operating experience. When the performance or condition of a structure, system or component does not meet established goals, appropriate corrective action shall be taken."

Though large transformers are non-safety-related, they are included in the scope of the Maintenance Rule (10CFR50.65), which poses the following question: " Has failure of the non-safety-related SSCs caused a reactor scram or actuation of safety-related system at your plant or a plant of similar design?" As such, reliability and availability criteria are applied and data are gathered to monitor the equipment performance against these criteria. Accordingly, plant-specific data gathered for Maintenance Rule purposes should also be useful for LCM planning purposes. Additionally, plant-level performance addressing the number of plant trips, capacity loss, and the number of safety actuations may also apply. For most plants the main and auxiliary transformers are considered risk significant (they feature prominently in the station blackout analyses) and would, therefore, require system-specific availability or reliability performance monitoring under the Maintenance Rule.

The EPRI "SYSMON" software program [10] contains recommendations for performance monitoring for 37 systems, but large power transformers are not among the systems addressed.

4.1.4 EPRI PM Basis Templates

EPRI TR-106857-V38, "Preventive Maintenance Basis for Transformers (Station-Type, Oil-Immersed)" [3] provides a preventive maintenance (PM) template (Table 4.3) and a strategy for preventive maintenance to address degradation mechanisms. It also provides the tasks identified in these templates, including the subtasks discussed in the PM task descriptions, which are listed in PM Strategies Table 4.4. The expert group has identified the most common failure locations (mechanisms for transformer accessories and components) as shown below:

- Bushing faults
- Cooler problems, especially oil leaks and fan failures
- Oil leaks
- Oil quality problems
- Load tap changer problems, especially contact misalignment, coking, and oil leaks

Table 4-3
Transformers (Station-Type, Oil-Immersed)

			Critical				**Non-Critical**			
			High Duty Cycle Severe Service Condition	**High Duty Cycle Mild Service Condition**	**Low Duty Cycle Severe Service Condition**	**Low Duty Cycle Mild Service Condition**	**High Duty Cycle Severe Service Condition**	**High Duty Cycle Mild Service Condition**	**Low Duty Cycle Severe Service Condition**	**Low Duty Cycle Mild Service Condition**
	Critical	Yes	**X**	X	X	X				
		No					X	X	X	X
	Duty Cycle	High	**X**		X		X		X	
		Low		X		X		X		X
	Service	Severe	**X**	X			X	X		
PM Task	Condition	Mild			X	X			X	X
Calibration and Testing				4Y	5Y	4Y			5Y	5Y
Vibration/Acoustic/Sound Level				1Y	NR	1Y			NR	NR
Thermography				6M	1Y	6M			1Y	1Y
Dissolved Gas Analysis (DGA)				3M	1Y	6M			1Y	1Y
Oil Screening				1Y	1Y	1Y			1Y	1Y
Lightning Arrester Leakage Monitoring				AR	AR	AR			AR	AR
Motor Current Monitoring				1Y	NR	1Y			NR	NR
Tap Changer Maintenance (load only)				2Y	NR	4Y			NR	NR
Cooler Maintenance				2Y	5Y	4Y			5Y	5Y
Bushing Cleaning				AR	AR	AR			AR	AR
Maintenance Inspection				4Y	5Y	4Y			5Y	5Y
Engineering Walkdown				3M	3M	3M			3M	3M

__Notes:__ The template does not apply to the run-to-failure components; non-critical here means not critical but important enough to require some PM tasks.
The shaded area indicates that no examples of station-type, oil-immersed transformers could be identified for these template conditions. If a utility were to identify a station-type, oil-immersed transformer that corresponded to a column in the shaded area it would be necessary to develop a PM program, probably similar to those stated. The shaded area does not mean run-to-failure.

Definitions:

- Critical-Yes: Functionally important, e.g., risk significant, required for power production, safety-related, or other regulatory requirements.
- Critical-No: Functionally not important, but economically important.
- Duty Cycle-High: Frequently cycled.
- Duty Cycle-Low: Continuous operation.
- Service Condition-High: 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, or operated in a backfeed mode.
- Service Condition-Mild: Absence of the above conditions.

Table 4-4
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint..	Cooler Maint..	Bushing Cleaning	Maint . Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Failure Location	**Failure Timing**	**Degradation Mechanism**													
Transformer Oil (mineral)	Random on a scale of years	Loss of dielectric strength				X	X							X	
Windings	Random on a scale of years	Insulation breakdown	X	X	X	X	X								
Gaskets	Expected to be failure free for ~20 years, some random	Leakage												X	X
Tank	Random on a scale of about 5 years, if tank is contaminated	Corrosion													
Core	Expect to be failure free for 40 years, assuming oil is degassed as needed	Loose		X		X									
	Expect to be failure free for 40 years, assuming oil is degassed as needed	Loss of core ground	X												
	Expect to be failure free for 40 years, assuming oil is degassed as needed	Multiple core grounds				X									

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	4-5Y	NR-1Y	6M-1Y	3M-1Y	1Y	AR	NR-1Y	NR-4Y	2-5Y	AR	4-5Y	Shift	3M
Core (cont.)	Random, on a scale of years	Shorted laminations	X			X									
Oil Filled Bushings	Expect to be error free for at least 15 years, some random	Leakage										X	X	X	X
	Expect to be failure free for 2-5 years, depending on severity of conditions	External contamination		X	X							X	X	X	X
	Random	Loss of BIL	X										X		
Solid Bushings	Random	Loss of BIL	X										X		
Lightning Arresters: (Metal Oxide Varistor type)	Random	Thermal runaway	X					X							
No-Load Tap Changer	Random	Misalignment	X			X									
	Random	Sheared gear pin, Contact Coking, etc.													
Load Tap Changer	Random	Misalignment, Contact Coking, etc.	X		X	X				X					
	Random	Damaged contacts	X	X	X	X				X					
	Expect to be failure free for 20 years	Leaks: gasket, piping, and valves				X				X				X	X
	Random, on a scale of years	Motor operator failure								X					X
Fins and Tube Coolers	Random	Airside fouling									X			X	X

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	4-5Y	NR-1Y	6M-1Y	3M-1Y	1Y	AR	NR-1Y	NR-4Y	2-5Y	AR	4-5Y	Shift	3M
Fins and Tube Coolers (cont.)	Expect to be failure free for 15 to 40 years	Loss of heat transfer			X						X			X	
	Random, on a scale of 20 years	Leaks: tube to header									X			X	X
	Expect to be failure free for about 20 years, some random	Leaking gaskets									X			X	X
	Random, can be immediate	Dresser Coupling leaks									X			X	X
Radiators/ Oil Coolers	Random	Airside fouling									X			X	X
	Expect to be failure free for 40 years, some random			X		X								X	X
Fans and Motors	Expect to be failure free for 7 to 10 years, some random	Bearing wear		X	X				X		X				
	Expect to be failure free for 40 years, some random	Winding insulation failure													
	Expect to be failure free for 40 years, some random	Fan blade cracks									X				
	Expect to be failure free for 10-15 years	Motor power cable deterioration									X				

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Pump and Motor	Expect to be failure free for 40 years	Bearing wear		X					X						X
	Expect to be failure free for 40 years	Impeller and volute wear		X					X					X	X
Pump and Motor (cont.)	Expect to be failure free for 40 years, some random	Winding insulation failure													
	Expect to be failure free for 10-15 years	Motor power cable deterioration									X				
Valves	Expect to be failure free for 10 years	Stem leaks												X	X
	Random	Disk detachment													
	Random, on a scale of 10 years	Bound or struck													
	Expect to be failure free for 10 years	Air in-leakage				X								X	
Sudden Pressure Relay	Expect to be failure free for 40 years, some random	Mis-operation	X												
Buckholtz Gas Volume Relay	Random	Mis-operation	X												
Level Alarms	Random	Mis-operation	X												
Pressure Gauge	Expect to be failure free for 5-7 years	Drift	X												

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Temperature Gauge	Expect to be failure free for 4-6 years	Drift	X												
Conservator Tank	Expect to be failure free for 40 years	Bladder failure				X							X		
	Expect to be failure free for 40 years, some random leaks	Fittings and connection leaks											X	X	X
Desiccant	Expect to be failure free for 40 years	Outlet breather valve fails to seal				X									
	Expect to be failure free for a few years	Depletion												X	
Gas Blanket Systems	Expect to be failure free for 10 years	Regulator failure												X	X
	Random	Leaking: pipes, tubing, fittings, gaskets, and valves												X	X
Pressure Relief Device	Random	Improper Operation												X	X
Electrical Connections	Random	Loose			X								X		
Control Relay		See EPRI Report TR 10687, Vol. 30, Relays-Control													
Timing Relay		See EPRI Report TR 10687, Vol. 31, Relays-Timing													

Table 4-4 (continued)
PM Tasks and Degradation Mechanisms (from EPRI TR-106857, V. 38)

		PM Task	Cal & Test	Vibration/ Acoustics/ Sound Level	Thermo-graphy	Dissolved Gas Analysis	Oil Screen	Lightning Arrester	Motor Current Monitor	Tap Changer Maint.	Cooler Maint.	Bushing Cleaning	Maint Inspect.	Operator Rounds	Engineer Walkdown
		Interval	**4-5Y**	**NR-1Y**	**6M-1Y**	**3M-1Y**	**1Y**	**AR**	**NR-1Y**	**NR-4Y**	**2-5Y**	**AR**	**4-5Y**	**Shift**	**3M**
Motor Starters, Breakers, and Transfer Contactors: Wiring, Fuses, and Lights		See EPRI Report TR 106857, Vol. 8, Low Voltage Electric Motors (600V and below)													

4.1.5 Current PM Activities and Candidate PM Tasks

The EPRI PM templates provide an optimum set of maintenance activities for a select number of important components. However, a cost-effective maintenance program may use simple tests to determine if more extensive testing should be performed. Internal and external maintenance operations are then performed when the test results so indicate. Based on a review of the industry best practices, the recommended tests are indicated in "Recommended Maintenance Tests" described in EPRI report 1000031 "Guidelines for the Life Extension of Substations" [4] and are summarized in Table 4.5. Table 4.5 provides minimum inspection maintenance frequencies. Table 4.3 provides PM tasks for transformer accessories along with the recommended frequencies, depending on the duty cycle and service condition of the transformer.

Table 4-5
Maintenance Tests, Routine Maintenance, Inspections and Frequency

Maintenance Task	Recommended Minimum Maintenance Frequency
Condition Assessment Tests:	
Oil dielectric strength and moisture content	1 year
Oil interfacial tension and acidity	2 years
Dissolved gasses in oil	1 year
Winding insulation and bushing power factor	5 to 7 years
Infrared thermography	6 months to 1 year
Routine Maintenance and Inspections:	
External inspection	3 months
Bushing cleaning	Determined by visual inspection
Heat exchanger maintenance	1 to 2 years
Calibrate gauges and relays	5 years
Functional tests	5 years
Load tap changer	2 to 4 years

4.2 NRC Generic Communications and Other Reports

4.2.1 NRC Communications

A review of generic communications issued by the NRC identified the following documents to be significant for their impact on large transformers and on the plant.

Information Notice 2000-14: Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power- Information Notice 2000-14 addresses the undetected damage from the failure of a bus duct, a passive component known for high reliability and often receives little preventive maintenance or attention. The phase-to-phase fault occurred in a 12 kV, non-Class 1E electrical bus duct from the unit auxiliary transformer to the switchgear that supplied power to the reactor coolant pump motors and the circulation water pump motors. The initial fault and the resultant arcing and smoke caused another fault in the 4 kV bus duct directly above the initial fault. An auxiliary transformer explosion in 1995, subsequent repairs, and inadequate fastener torques were the probable cause, resulting in a heated joint and leading to failure.

Information Notice 97-037: Main Transformer Fault With Ensuing Oil Spill Into Turbine Building addresses the main transformer low voltage bushing failure that caused an oil spill into the turbine building via the isolated bus duct. This notice presents a case in which a large amount of transformer insulating oil could bypass fire hazard control features, such as oil impoundment pits, and spill into the turbine building and other areas of a nuclear power plant.

Information Notice 82-053: This notice discusses the "Main Transformer Failures at the North Anna Nuclear Power Station," and describes seven main transformer failures, including one that resulted in a fire and one that caused extensive damage to the main generator.

4.2.2 Other Nuclear Industry Data

Select nuclear plant experience records are summarized here to identify the types of failures occurring with large power transformers.

SER 1-96, Transformer Explosion and Loss of Off-Site Power: On October 21, 1995, during a refueling outage, an explosion and fire occurred on one of the PWR unit auxiliary transformers. As a result, Unit 1 lost off-site power. During the restoration, a temporary grounding breaker located in one cubicle of the non-vital bus was accidentally left in place on the bus. When the feeder breaker from the auxiliary transformer was closed to energize the bus, a direct electrical path to ground was created causing a current surge that ruptured the transformer and initiated the explosion and fire.

SER 47-85, Loss of Off-Site Power: On August 16, 1985, at a BWR, a transformer fault and subsequent failures in the automatic transferring of loads resulted in a loss of off-site power to one unit. Due to a failed insulating board, a fault occurred on the secondary side of the transformer supplying Unit 1 loads, causing a short across the bus duct housing.

SER 52-85, Loss of AC Power and Feedwater Line Water Hammer: On November 11, 1985, at a PWR, a transformer trip led to a reactor trip and temporary loss of AC power.

SEN 128, Transformer Explosion and Loss of Off-Site Power: On October 21, 1995, at a PWR, an explosion and fire occurred on one of the Unit 1 auxiliary transformers. Investigations indicated that the auxiliary transformer was unintentionally grounded through a grounding breaker installed on an associated 12 kV bus.

OE14036 and Event Number: 374-020304-1- Main Power Transformer Insulating Oil Low Dielectric Value: On March 4, 2002, at a BWR, the results of a routine main power transformer dissolved gas oil analysis showed a dielectric value of 18 kV, which is below the Nuclear Equipment Insurance Limited (NEIL) lower limit of 26 kV. Three additional samples taken during the next five weeks showed dielectric values to be above the NEIL limit. The low values were ultimately attributed to particulates in the transformer oil after detailed evaluations eliminated sampling techniques and water as causes. A filtering system was subsequently installed to remove and analyze particulates.

OE11645, OE 11418, Fire in Unit 2 "B" Main Transformer: On September 22, 2000 at a BWR, "B" phase main power transformer (2B MPT) caught fire, which was limited to the top portions of the transformer.

OE13116, OE12778, OE12564, Event Number: 265-010802-1 Scram Due to Lightning Strike and Fire in Main Power Transformer: On August 2, 2001, at a BWR, a lightning strike on a transmission line two miles from the station resulted in a failure of the main power transformer and an automatic reactor scram. The resultant transformer fire was extinguished in approximately 30 minutes by actuation of the transformer's fire protection deluge system, the site's fire brigade, and an offsite fire department. The root causes of the transformer failure were design and construction errors that resulted in mechanical failure of the bus bar clamps. The bus bars and bus bar fiber bolting material were undersized. These conditions led to increased heating, bus bar motion, and stress on the clamps. Other factors included the vulnerability of the affected transmission line to lightning strikes, exposure of the transformer to a large number of electrical faults, and the failure to increase inspection and monitoring following these faults.

OE9613, Transformer Tap Changer Causes Diesel Generator Start: On December 22, 1998, at a PWR, during heat-up from a forced outage, a malfunction of the safeguards transformer automatic tap changer resulted in an undervoltage condition on plant 2400 VAC safety-related buses. The safeguards transformer is the normal power supply for the safety-related buses. A contactor, which causes the tap changer motor to move to lower positions, developed a three to four second delay in opening. This delay apparently resulted from the effects of cold weather acting on the contactors, which had been in service for nine years.

OE3289, Main Power Transformer: On March 23, 1989, at a PWR, the plant was taken out of service due to a high accumulation of combustible gases in Phase A of the main power transformer. The gassing had been attributed to the heating of "T" beam, low voltage short series leads, and corona shield.

OE12677, Event No. 272-010613-1, Event No. 272-010708-1, Power Reductions Due To The Loss of No. 1 Station Power Transformer: On June 13, 2001, the No.1 station power transformer (SPT) protective relay circuit actuated, tripping one section of the station 500 kV ring bus. Investigation of the event found that the No. 1 SPT phase-B regular differential relay target (DHR) actuated. The cause of the event was aging. Discussions with the original equipment manufacturers (OEM) established that there is no effective way to determine remaining service life, and no effective way to monitor surge arrester performance. The OEM recommendation for surge arresters is to implement a replacement program for those arresters 20 years of age or older. Long-term corrective action is to test each surge arrester periodically.

OE2150, RX SCRAM By Actuation Of Transformer Sudden Pressure Relay: On June 26, 1987, at a BWR, unit tripped during startup by actuation of a sudden pressure relay located on an auxiliary power transformer. The cause of sudden pressure relay actuation was the opening of a test (poppet) valve located on the relay.

OE9670, Transformer Fault due to Cracked Bus Bar Insulator on One Phase of Transformer's Secondary: On December 27 at a BWR, a cracked bus bar insulator on one phase of the transformer's secondary permitted electrical "tracking" to ground and consequently actuated overcurrent relays to automatically open the breaker to isolate the fault.

OE9082, Hot Connection Found In Unit Two Main Power Transformer: On June 2, 1998, at a BWR, a hot connection was found in the Unit 2 main power transformer local control cabinet while performing thermography.

OE2186, Auxiliary Power Transformer Failure: On June 6, 1986 at a PWR, a transformer failed and physical entry into the transformer and visual observations found debris of paper insulation and small amounts of copper particles. The cause of the failure was an overheating problem in the leads.

OE9246, Main Transformer Sudden Pressure Device Failure: On August 17, 1998, at a PWR, a main power transformer sudden pressure device actuated.

OE5127, Automatic Scram Due to Main Power Transformer Failure: On January 4, 1992, at a BWR, a sudden pressure relay actuated which caused both switchyard breakers to open and de-energize the three main power transformers.

SOER 02-3: From a review of SOER 02-3, which documents events from 1991 to 2001, sufficient information on the operating performance of large transformers is at hand to draw a reasonable conclusion on the performance of large transformers. The conclusions are presented in Sections 4.1.1 and 4.1.2 of this sourcebook.

4.3 Experience in Fossil Power Generation and Industrial Facilities

The subject transformers are also used in fossil plants and in other industries. This section discusses the experience with large power transformers in applications in other industries.

The failure data for transformers shown in Table 4.6 was extracted from the German Nuclear Utility Association represented by VGB [12] and European Reliability Data [13] for the relevant components. The former represents both BWR and PWR units and the latter represents PWR units.

Table 4-6
European Nuclear Power Plant Failure Data

COMPONENT	TYPE/SIZE	FAILURE RATE (1/HR of operation)	DATA SOURCE
Transformers	2.8-4.2 MVA	5.09 E-7	VGB
Main Transformer	24KV	2.2 E-6	EDF

Hartford Steam Boiler (HSB) analyzed the transformer failures that occurred in 1975, 1988, and 1998 [14] for various industries such as power plants, commercial buildings, manufacturing and metal processing facilities. The transformers analyzed included various applications. HSB concluded that the monetary losses arising from power transformer failures are the largest of the monetary losses arising from all transformer failures. Table 4.7 provides failure data for each failure cause as a percentage of the total failures. These failures are graphically shown in Figure 4-6.

Table 4-7
Analysis of Power Transformer Failures for 1975, 1988, and 1998

	1975	1988	1998
Lightning Surges	32.3%	30.2%	12.4%
Line Surges/External Short Circuit	13.6%	18.6%	21.5%
Poor Workmanship of Manufacture	10.6%	7.2%	2.9%
Deterioration of Insulation	10.4%	8.7%	13.0%
Overloading	7.7%	3.2%	2.4%
Moisture	7.2%	6.9%	6.3%
Inadequate Maintenance	6.6%	13.1%	11.3%
Sabotage, Malicious Mischief	2.6%	1.7%	0.0%
Loose Connections	2.1%	2.0%	6.0%
All Others	6.9%	8.4%	24.2%

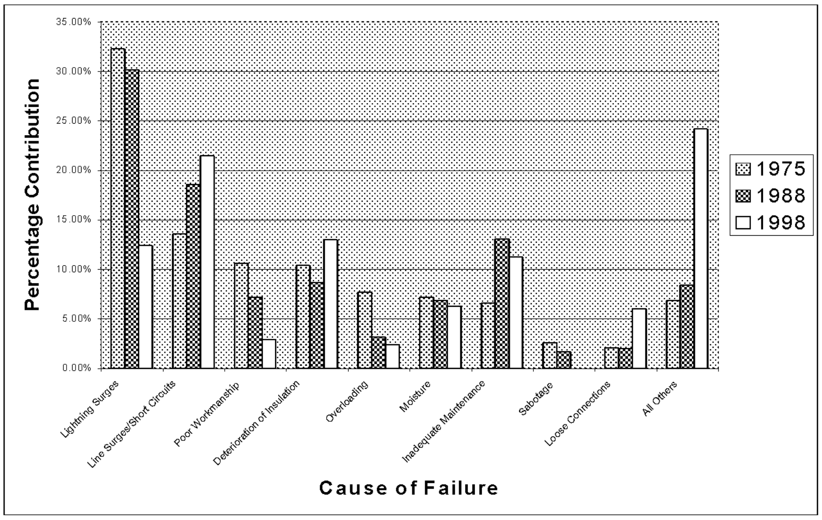

Figure 4-6
Number of Transformer Failures by Year

The HSB study concludes that line surges are the number one cause of all types of transformer failures. The second leading cause of failures is insulation deterioration. The average age of the transformers that failed due to insulation deterioration is 17.8 years, appreciably less than the expected life of 35 to 40 years. Inadequate maintenance is the next leading cause of transformer failures. This category included improper controls, loss of coolant, accumulation of oil and dirt, and corrosion. The study concluded that a planned maintenance, inspection and testing would significantly reduce the number of transformer failures and the unexpected interruption of power.

The Canadian Electricity Forum, Electricity Today, Issue 1, 2002 [15] published an article on transformer maintenance. The article includes dry type, oil-filled, and fluid-filled transformers. Causes of transformer failures are summarized in Table 4.8 and include failures for all three types of transformers. Although this data is for all three types of transformers large and small, it indicates that 73% of transformer failures are caused by insulation breakdown. The insulation breakdown is attributed to insulating liquid and/or winding coil failure.

Section 6.1 discusses applicable aging mechanisms and effects on transformer components.

Table 4-8
Transformer Component Failures

Transformer Part Failures	Percentage Contribution to Total Failures
High Voltage Windings*	48.00%
Low Voltage Windings*	23.00%
Bushings*	2.00%
Leads	6.00%
Tap Changers	0.00%
Gaskets	2.00%
Others	19.00%
Total	100.00%
* Components of Insulation System	

5
GUIDANCE FOR PLANT-SPECIFIC SSC CONDITION AND PERFORMANCE ASSESSMENT

This section addresses steps number 8, 10 and 11A in the LCM planning flow chart (Figure 2-1b) and provides guidance for the plant-specific LCM planning for large transformers. Also included in this section (Section 5.4) is a compilation and description of available and useful condition or performance monitoring programs.

- In Step 8, the plant-specific operating and performance history is compiled, as discussed in Section 5.1 below.
- Step 10 comprises a compilation and review of the plant-specific maintenance program for large transformers, leading to the establishment of a complete inventory of the current maintenance tasks and providing a basis of determining if enhancements or changes are desirable.
- In Step 11A, the intent is to characterize the present plant-specific physical condition and performance of the large transformers and the implementation of effective preventive maintenance procedures, diagnostics and component condition monitoring. The assessment of the maintenance tasks should pay close attention to whether and how the tasks address any deviations identified in this SSC performance assessment and the SSC condition review. The deviations may be positive in that plant-specific SSC performance and conditions are superior to the industry average, in which case unnecessary or too frequent PM may be performed, or the deviations may be negative, indicating a need or opportunity for improvement. Details of the condition and performance assessments are discussed in Section 5.3.

5.1 Compiling SSC Operating and Performance History

The current condition and age of large transformers have a major bearing on the LCM planning choices. In conjunction with performance reviews, a thorough assessment of the existing equipment is of paramount importance in making realistic decisions as to what maintenance options or strategies are feasible. Several elements are needed to complete the SSC condition review. These include reviewing records of the periodic visual inspections, reviewing diagnostic test and monitoring device data, test results which have been performed on the equipment, predictive technologies employed and results, modifications, work orders, and refurbishment data.

5.1.1 SSC Condition Reviews

The performance review of plant transformers is important in determining the options and includes:

- Assembling the maintenance history for transformers, particularly the corrective maintenance actions from the last five years (as a minimum). The maintenance history may also provide evidence of performance concerns or failures of other critical components, such as bushings, surge arresters, coolers, gaskets, fans, and load tap changers.
- Trending the failure rates to identify any specific type of transformer components that may exhibit unusual performance challenges or high failure incidents.
- Reviewing the inspection reports and condition monitoring reports to see if the current maintenance is effective in maintaining the equipment.
- Reviewing the Maintenance Rule (MR) performance parameters and trends, the system health reports, MR periodic assessments and the effectiveness of corrective actions implemented.
- Reviewing plant scrams and trip history to determine the events attributable to the large transformers and their components. For those events caused by the large power transformers, the lost power generation due to forced or unforced plant trips, scrams, extended outages, partial power operation or hot standby conditions is evaluated to determine the historical cost of the transformer failures. The results provide a basis for projecting future trends for LCM planning.
- A review of design changes and technology upgrades that have been instituted for replacement and equipment upgrades.
- Thermography, acoustics, oil analysis, regular walkdowns, and condition monitoring are some of the more effective tools for condition assessment and trending.

5.1.2 Periodic Visual Transformer Inspections

A condition assessment entails a visual inspection of the external condition of a transformer to look for abnormalities such as:

- Oil spills
- Paint deterioration, discoloration, peeling
- Evidence of corrosion, rust
- Staining from water or oil leaks
- Foundation crumbling, cracking (indicates abnormal thermal expansion)
- Loose and missing parts
- Deformation, vibration of tubing, coils, fans, conduit
- Audible corona discharge

- High sound level, humming
- Burning smell, ozone smell
- Damaged or chipped/cracked bushings, or lightning arresters
- High or low oil levels
- Loose grounding or terminal connections
- Other signs of abnormal conditions

5.1.2.1 Inspection Frequency

A periodic transformer inspection is an effective maintenance tool for locating situations and problems that are not indicated by sensors or other means. The problems are usually noted early so that corrective action can be taken before a more serious condition occurs. Transformers with a history of problems should be inspected frequently.

5.1.2.2 Typical Inspections

The following is a list of typical transformer inspection tasks and are applicable to most outdoor power transformers. It should be noted that the items inspected would depend on the equipment installed on the transformer and the record of performance in service. Those plants that perform inspections more frequently do not necessarily check all the following items during each inspection.

- Check transformer and auxiliaries such as tap changers and bushings for oil leaks. Record the location of the leak and the degree of leaking.
- Check operation of fans and pumps.
- Check to see that the proper cooling equipment is in operation. This procedure involves checking the oil temperature gauges to determine whether the cooling should be in operation.
- If the cooling equipment is in operation, note whether the appropriate fans and pumps are operating. Record any equipment not in operation. Check flow gauges on pumps.
- If the cooling equipment is not in operation, some utilities manually turn the equipment on to ensure that all fans and pumps are operative. Check flow gauges on pumps. Record any equipment not operating properly.
- Check for any abnormal noises, including pumps and load tap changers.
- Check the temperature of the load tap changer compartments with the infrared scanner for any abnormal temperature conditions.
- Check the temperature of the radiators with an infrared scanner. Investigate both high and low-temperature areas.
- Check all liquid level gauges for proper level including main tank, tap changer compartments, oil expansion tanks, and bushings.

- Check the bushings for chipped or broken sheds. At intervals, check the terminals for hot spots using the infrared scanner. Report any abnormal terminal temperatures immediately since bushing damage can result.
- Inspect all temperature devices. Record temperatures. Reset all maximum temperature indicators on the gauges.
- Check the pressure relief device to ensure that the device has not operated.
- Inspect all dehydrating breathers. Report any that indicate saturation with water.
- Check the nitrogen system including the bottle on transformers having nitrogen blanket oil preservation systems:
  - Report any increased usage of nitrogen.
  - Replace or have the bottle replaced if the pressure is below 300 psi.
- Inspect the paint and report any rust spots.
- Check all control devices such as gas collector and sudden pressure relays.

  Open the control cabinet door and inspect the devices:
  - Is the space heater operative?
  - Has water collected on the bottom of the cabinet?
  - Is the wiring in good condition?
  - Visually inspect the transformers and the auxiliaries. Report any unusual conditions.
- Inspect the lightning arresters.
- Check the heat exchangers:
  - Are the radiators and coolers clean?
  - Are the radiators and coolers warm at the bottom indicating that they are operating satisfactorily?
  - Does the airflow from the fans through the radiators and coolers appear to be normal? Is the air hotter than the surrounding air?
- Check the operations counter for the load tap changers. Report any usually high or low number of operations.

5.1.3 Review of Diagnostic Tests and Monitoring Devices

Review all available diagnostic tests and monitoring devices such as:

- Gas-in-oil-analysis
- Oil condition and dielectric strength
- Operational monitoring
- Original factory test report

- Insulation resistance and power factor
- Turns ratio
- Winding resistance
- Other monitoring and test results as described in Section 5.4, Condition Monitoring Technologies.

Gas-in-oil analysis is the primary method for determining the nature of problems within the transformer.

- High CO and CO2 accompanied by H2 without the presence of hydrocarbon gases such as CH4 (methane), C2H6 (ethane), and C2H4 (ethylene) are indicators of deterioration of paper caused by high oxygen and water contents in the system.
- High CO and CO2 with the presence of CH4, C2H6, and C2H4 are indications that there is overheating in an insulated part of the transformer.
- Significant amounts of CH4 with similar amounts of C2H4 with lesser amounts of C2H6 are indications of hot metal gases.
- Significant amounts of H2 with smaller amounts of other gases are an indication of partial discharges in the system. H2 can also be generated by free water in contact with the electrical steel of the core or by an overheated core.
- Acetylene (C2H2) is usually an indicator of arcing.

The water content of the oil and the paper can be estimated using the water content of the oil and the temperature of the oil when the sample was taken. The power factor and interfacial tension of the oil are indicators of contaminants in the system. The dielectric strength of the oil gives a general indication of the dielectric strength of the insulation system since oil is the weak link in the system.

In many cases, tests on oil samples taken while the transformer is in service provide the first clues of the internal condition of the transformer. Shown below is a list of "key gases" in relationship to the transformer insulation condition. Analysis of the key gases, depending on the level and quantity, i.e., parts per million (ppm), provides the internal transformer condition and gas activity.

- High concentration of carbon monoxide – thermal damage to cellulose
- High acetylene – internal arcing
- Carbon particles in the oil – probable internal electrical breakdown

If test results are available, the transformer condition assessment is made easier as shown below:

- Low oil dielectric strength – moisture or particle contamination
- Low insulation resistance – moisture contamination or damaged insulation
- Abnormal turns ratio – short turns in the windings

Table 5.1 [4] can be used to assess the overall condition of the transformer based on the results of the dissolved gas tests. Trending of the parameters based on the test results of the key gas concentration will provide the transformer condition and operational limits. Once it is determined that the concentration of certain gases is above normal, individual gas ratios can give further indication of the type of fault causing the high levels. Rogers ratios are a common tool for assisting with this determination.

Since all normally operating transformers will have some levels of the above-mentioned gases dissolved in oil, with the exception of acetylene, it is important to identify concentration levels for which the user should have concern. IEEE Std. C57.104, "Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers" [25] provides the guidance. Table 5.1 presents the key gas concentration levels and conditions that may require further action.

Table 5-1
Dissolved Gas Concentration

	Dissolved Key Gas Concentration Limits (ppm)							
Status See Notes	H_2 Hydrogen	CH_4 Methane	C_2H_2 Acetylene	C_2H_4 Ethylene	C_2H_6 Ethane	CO Carbon Monoxide	CO_2 Carbon Dioxide	TDCG See Notes
Cond 1	100	120	35	50	65	350	2,500	720
Cond 2	101-700	121-400	36-50	51-100	66-100	351-570	2,501-4,000	721-1,920
Cond 3	701-1,800	401-1,000	51-80	101-200	101-150	571-1,400	4,001-10,000	1,921-4,630
Cond 4	>1800	>1,000	>80	>200	>150	>1,400	>10,000	>4,630

Notes:

TDCG =Total Dissolved Combustible Gas (Excludes CO_2)

Cond 1 =Dissolved gas in this range indicates normal operation.

Cond 2 =Dissolved gas in this range indicates greater than normal gas generation. Begin analysis.

Cond 3 =Dissolved gas in this range indicates a high level of insulation decomposition. Sample frequently to establish the trend of gas evolution and apply gas ratio analysis for diagnosis.

Cond 4 =Dissolved gas in this range indicates excessive decomposition. Continued operation could result in failure of the transformer.

5.2 Review of Current Maintenance Plans

5.2.1 Compiling Maintenance History

To develop a clear picture of past equipment performance from which projections can be generated, a thorough review of the maintenance history is needed. This maintenance history is captured by most plants in Work Orders (WO), often managed by the plant computerized maintenance management system (CMMS). Work orders are written to execute preventive maintenance or corrective maintenance and to implement other activities, such as design changes, replacements, or upgrades.

The most important WOs are those implementing corrective actions as a result of equipment failures, performance enhancements, and design changes. They often contain information concerning the root cause of the failure to assure that the corrective action is effective, whether repetitive failures were involved, the cost and man-hours spent in the corrective action, and the reason why the failure was not detected in the incipient stages. This information is used to identify additional preventive maintenance (PM) or predictive maintenance (PdM) activities; potential enhancements to the current maintenance program; and/or the need for replacement, redesign, or upgrades. The basic premise is that the performance can only be improved by preventing failures; therefore, it is critical to identify the historical failure causes and to determine the action that could have prevented the failure.

The work order review also provides detailed information as to the component failure rates presently experienced by the large transformers. These rates can be compared with the generic data presented in Section 4 to ascertain whether there is the potential for significant reductions in failure rates. These actual failure rates are also used in the economic modeling of LCM plans to calculate the cost of corrective maintenance and the consequences of component failure (lost power production, regulatory cost, the costs of monitoring under the Maintenance Rule, EPIX reporting, etc.).

The work order review can also be used to trend the annual corrective maintenance activities over past years to see if the equipment failures are increasing or decreasing, and what additional corrective actions may be justified to effect a positive change.

Lastly and most importantly, a review should be conducted of all the plant transients, power reduction events, and scrams since plant operation began. This review should focus on the cause of the event, the principal systems or components involved, and whether the large transformer was a direct or indirect contributor to the event.

5.2.2 Inventory of Current Maintenance Activities

Once the plant-specific maintenance history has been compiled, the current maintenance activities need to be identified. When using the word "maintenance" in LCM planning, the activities associated with the system include preventive, predictive, and corrective actions, whether required by regulations (testing, inspection, surveillance, walkdown, monitoring, sampling), by applicable codes (ASME, NFPA, state requirements, local requirements); by the insurance carrier, or by plant procedures, programs, or policies. Collecting the associated activity parameters, such as the annual frequency of the task, the number of components involved, labor hours required, indirect labor associated with the activity, and the material costs, will provide the key input to developing a base case for LCM planning. This base case is not only important to create an inventory of the current activities and the total annual maintenance cost for the system, but it provides a benchmark for comparison to industry practice and a basis from which the need for additional activities, enhancements, or task reduction opportunities can be judged.

Intervals should be determined and adjusted by each utility based on individual plant experience, OEM information notices, and insurance and regulatory requirements. Intervals provided in the EPRI PM template are suggested starting points for this process, although in general, where these tasks are already being performed, the existing intervals could be used as the starting point providing a basis exists. Such a basis could be constructed from diagnostic data, past inspection data and failure history, and from information in this document. A key point is that it is prudent to change time-directed intervals so that intervals are short enough to protect against unacceptable equipment deterioration, but not so short as to waste maintenance resources or to introduce unnecessary sources of maintenance error.

When selecting time intervals for intrusive PM tasks, it is not necessarily conservative to select shorter rather than longer time intervals in a possible range. Shorter intervals expose the equipment to more opportunities for maintenance error and to the potential for non-optimal setup. Furthermore, reliability data for other complex plant component types suggest that components receiving a higher proportion of intrusive preventive maintenance tasks may experience more failures than those, which receive predominantly non-intrusive maintenance.

The following information should be considered when an inspection, maintenance, or a condition assessment is performed.

5.2.2.1 Pumps

Bearing wear and other mechanical failures in oil pumps are believed to be the cause of failure in some major power transformers. The particles generated can get into high stressed electrical areas causing failure. At the present time, there is no effective way to test pumps in service for such conditions; however the acoustic signature of the pump in operation could give an indication of problems, but this requires a baseline acoustic signature for comparison. It is recommended that the following actions be considered.

Some utilities recommend change-out of the oil pumps on a regular basis. The time interval depends on the time that the pumps are in operation and the experience with each pump design. All bearings, either sleeve or ball, will eventually become worn and require replacement.

- Industry experience shows that some pumps have a history of problems in service. It is recommended that these pumps be replaced when they have been in service for a long period of time. Replacement time depends on the maintenance program and the condition of the pumps.

- When pumps are replaced on operating transformers or on repaired units, it is recommended that the pumps either be replaced with new pumps that are reliable or be rebuilt with improved bearing systems.
- For large generator GSUs, it is recommended that consideration be given to the installation of pumps with bearing monitoring systems so that any problems can be detected before dangerous particles get into the transformer system.

The operating of pumps (and fans) on coolers should be rotated on a regular basis. They are usually arranged in groups that are activated by the cooler temperature controls. Rotating the groups will assist in balancing the wear on the pumps. Some utilities have automatic controls that rotate the groups that come on first each time that the cooling equipment is deactivated.

5.2.2.2 Bushings

High voltage bushings must be maintained free of any external contamination and should be examined on a regular basis. The porcelain insulation should be examined for chips, cracks, and oil leakage. The main objective is to prevent flashover that could lead to catastrophic failure.

External contamination builds continuously and might become severe enough to cause electrical breakdown after two to three years on non-coated bushings depending on conditions. It should be noted that bushing faults of various kinds are relatively common failure causes for oil-filled transformers. Inspection will be required more often in atmospheres where salts and dust deposits collect on bushings.

- Some utilities replace all bushings if the transformer is 20 years or older and life extension work is undertaken.
- Most utilities replace the bushings if the power factor is high. A common metric used for oil-filled bushings to indicate high power factor, is either a doubling of the initial value (nameplate) or a value greater than 1%, whichever is the lowest.
- Several utilities have replaced one type of bushing that has had a record of failures over the years with bushings having new and improved design features.

5.2.2.3 Control and Protective Devices

Some utilities replace all control and protective devices if a transformer life extension program is initiated. Such devices are low cost, and the risk is great enough on older transformers to justify the cost.

Such devices are sometimes tested and replaced if they are defective. Critical protective devices, such as sudden pressure relays, are quite often replaced if the transformer is approximately 20 years old. The control wiring is replaced if it shows signs of severe deterioration, which may be the case for older transformers.

5.2.2.4 Gas Cushion Oil Preservation

Super-saturation of the oil with nitrogen may result when the temperature of loaded transformers with gas cushion oil preservation system is decreased rapidly (by dropping the load in cold weather and/or rain). This problem is well known, and most utilities have replaced the pressure controls that allowed the pressure to increase up to 6 psig (41 kPa) before the system started to release the nitrogen to the atmosphere. The controls have been changed to release nitrogen at around 3 to 3.5 psig (20.5 to 24.1 kPa). For some important EHV transformers, the nitrogen system has been replaced with expansion tanks with rubber bags.

If the nitrogen cushion designs are not properly maintained, failure of transformers can result. If the bottle becomes empty and is not replaced, the pressure in the gas space can become negative causing gas bubbles to evolve from the saturated oil.

The cost to maintain such systems can be high (particularly for transformers with varying loads) such that the system releases nitrogen to the atmosphere at a high rate. The bottles of dry nitrogen have to be replaced frequently. In some cases, the overall cost can be reduced if the nitrogen system is replaced with an expansion tank. The replacement of the gas system with the expansion tank should be considered for life extension of transformers. If this decision is made, it is important to specify a non-gas permeable material be used as the membrane.

5.3 Conducting the Condition and Performance Assessment

The generic performance data and information presented in the preceding sections can be used for plant-specific LCM planning in many ways. In particular, for plants not having a large data basis of experience, the generic data provides a basis for a sound component-specific PM program. Furthermore, the data may be used for comparison trending or projecting performance or failure data into the future when attempting long-term LCM planning. If the plant is of recent vintage, the failure data provides an indication of the types of failures to be expected as the plant ages and shows potential precursors of problems to be anticipated. Lastly and most importantly, the benchmarking of plant-specific data against generic (or industry) performance data for large transformers provides LCM planners with information with which to focus on areas in which there are significant opportunities to achieve economic and technical improvements. The steps involved in plant-specific performance and condition assessment (including benchmarking) can be summarized as follows:

Transformer life is shortened by a number of events. In addition to these failures, controlling the characteristics of the internal transformer system, such as oxygen and water content, will extend transformer life.

Based on a review of the generic data on plant trips due to transformers, the most frequent trips occur due to:

- Bushing failures
- Spurious Sudden Pressure Relay (SPR) activation
- Lightning strikes

- Loss of cooling
- Inadvertent actuation of FP deluge system
- Gas-in-oil generation
- LTC failures
- Human errors

Although the above events are not in the order of frequency or significance, the information from reported events can be used to compare plant-specific performance data to generic (or industry) performance data for large transformers. In Section 4, Table 4.1 and Figure 4-3 show the cause of transformer events and failures due to transformer internal failures, external causes, and other causes. These events are based on INPO's gathering of information for the last 10 years. The benchmarking of plant-specific data against generic (or industry) performance data for large power transformers provides LCM planners with the information needed to focus on areas where significant opportunities to achieve economic and technical improvements exist. The steps involved in benchmarking can be summarized as follows:

- At the system level, benchmark the contribution of large power transformers to the total plant lost power generation against the industry PWR/BWR specific average (Table 4.2). This will provide a preliminary assessment as to the current and past plant system health and indicate if the large power transformers in the unit perform at, above or below industry averages with respect to lost power generation and associated impact on plant safety.
- At the component level, compare plant-specific transformer component failure rates with those discussed in Section 4.1 and Tables 4.1 and 4.6 (European data) to diagnose and identify potentially unacceptable component performance.
- Compare the plant-specific transformer maintenance tasks against the industry recommendations (Tables 4.3 to 4.5) to identify opportunities for addition or deletion of PM or PdM activities and adjustments to the associated task intervals. If the performance of the transformers has been exceeding the industry standards and failure rates are below average, changes to the transformer PdM/PM program should be implemented cautiously and with good reason. On the other hand, if the performance of the transformers measurably lags industry average and the plant transformer PdM/PM program significantly deviates from the industry recommendations, the deviations should be reviewed critically to identify the causes and any opportunities for enhancement.
- Review operating and loading practices to ensure transformer performance and operation are within rated values specified in the design and nameplate data provided by the manufacturer.
- Review the corrective work orders and root cause evaluations of transformer failures to determine if the failure causes are commensurate with the industry experience.
- Similarly, from the corrective work order review, tabulate the failure detection modes for the failed transformers to determine if the plant's preventive and predictive maintenance program is capable of detecting transformer degradation and incipient failures.
- To assure that the long term maintenance plans include a thorough and critical review of aging and obsolescence concerns, establish the plant transformer failure rates, projected spare

parts use, potential replacement models or refurbishment kits, current spare parts inventory, exchange or reuse opportunities and reliable suppliers of parts, services and replacements.

- Large transformers are usually custom made and it can take up to one year to obtain a new one. Rewinding also can take from six to twelve months. Therefore, the plant should identify alternate procurement methods such as identifying available spare transformers and possibly establishing supply agreements.

5.4 Condition Monitoring Technologies

A review of transformer inspection results and data from monitoring devices may require that further tests be performed. Analysis of the test results will provide information regarding the internal condition of the transformer, the next steps for further sampling, and the recommended test sequences.

5.4.1 Recommended Test Sequences

It is recommended that tests be performed in sequence as shown in Table 5.2, which is based on the principle of using oil testing to determine when further testing is required, depending on the condition of the dissolved gas concentration from Table 5.1.

Table 5-2
Recommended Test Sequences

Gas-in-Oil Tests	• Sampling ASTM D 3613
	• Analysis ASTM D3612
	• IEE Std. C57.104
Dielectric Tests	• ASTM D 1816 for the main tank oil
	• ASTM D 1816 and ASTM D877 for load tap changer compartments
Water-in-Oil Test	• ASTM D 1533
Oil Power Factor Test	• ASTM D 924
General Oil Tests	• Interfacial Tension (IFT) ASTM D 971
	• Color ASTM D 1500
	• Some utilities also make other tests such as acidity, viscosity, and oxidation stability. However, these tests are not usually recommended unless an extensive study is being made to determine if the oil should be replaced.
Insulation Power Factor Test	• IEEE Std. C57.12.90 Part 10.10 [6]
Other Possible Tests When Required	• Detailed oil tests • Particle count and identification

Table 5.3 [4] shows the recommended test intervals for the general and gas-in-oil tests. These intervals can be varied depending on the condition of the transformer, the history of the transformer, and the history of the transformer accessories. The frequencies shown are typical guidelines. If the transformers have a history of good operation with no problems, the time interval between tests can be increased. If there is indication of some abnormality, the time interval needs to be shortened.

The manufacturer's requirements should be followed for oil testing during the warranty period. If there are no such recommendations or requirements, it is recommended that all tests be made at the end of the first year in service and prior to warranty expiration. Subsequent testing should follow Table 5.2 if there are no other manufacturer requirements.

Table 5-3
Typical Maintenance Oil Test Frequency

	General Oil Tests	Dielectric & Water	Gas-in-Oil
Less than 100 MA three phase and 230 kV or less	1-3 years	1-3 years	1-3 years
Greater than 100 MVA three phase 230 kV or less	1-2 years	1-2 years	1-2 years
Greater than 100 MVA three phase, greater than 230 kV	1-2 years	1 year	1 year
All generator step-up	1-2 years	1 year	1 year

5.4.2 Gas-In-Oil Analysis

One of the most useful and widely used condition assessment techniques involves sampling and analysis of gases dissolved in the oil of operating transformers. Sampling intervals are typically from one to three years depending on the size and voltage of the transformer, with more frequent sampling for large, critical units and less frequent sampling for smaller, less critical units. There are three standards that address condition assessment sampling: ASTM D 3613 for analysis, ASTM D 3612 for interpretation, and IEEE Std C57.104-1991, "General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers" [25].

The goal of the sampling process is to collect a representative sample, while avoiding entrance of contaminants, and to preserve the integrity of the sample until it is analyzed.

It is recommended that samples be taken from a convenient valve at the bottom of the tank, which may be equipped with a sampling adapter; the use of a syringe for sampling is preferred.

It is expected that dissolved gas content is well equilibrated within the tank as a result of thermal convection of the oil, but water content may be greater at the bottom. Normally the same samples are used for dissolved water and dissolved gas analyses. Samples may be taken from energized apparatus provided it is certain that a positive pressure exists at the sampling point. It could be disastrous if the pressure was negative and air bubbles were drawn into the equipment.

5.4.3 Dielectric Strength Guidelines

ANSI/IEEE Standard C57.106-1991, "Guidelines for Acceptance of Insulating Oil in Equipment" [7] has guidelines for the dielectric strength of oil in operating transformers, which are shown in Table 5.4. The recommended test limits are for oil in service and are suggested limits for continued use of service-aged insulating oil by voltage class. Standard C57.106-1991 [4] Section 5, provides additional information when tests do not meet the suggested limits. The values shown in the standard are approximately 7-15% lower than the recommended values for new oil in equipment after filling but before energizing.

Table 5-4
Dielectric Strength Guidelines

Test & Method	Minimum Dielectric Strength (kV)		
	< 69 kV	69-288 kV	> 345 kV
ASTM D 1816:			
• 0.040-in. (1-mm) gap	23	26	26
• 0.080-in. (2-mm) gap	34	45	45
ASTM D 877:			
• 0.100-in. (2.5-mm) gap	26	26	26

5.4.4 Dielectric Tests

Although the dielectric strength and water-in-oil tests are separate tests, oil samples for both tests are normally taken at the same time. There are two test methods available for determining the dielectric strength of oil. In the main tank, the ASTM-D-1816 method is used. This standard allows an electrode gap dimension of either 0.040 inches or 0.080 inches. Testing with the 0.040-inch gap is more widely used and recommended. Samples should be taken in accordance with ASTM-D- 3613 and D-923.

If the transformer has a load tap changer, either the ASTM-D-877 or the ASTM-D-1816 test method may be used. If the tap changer has sharp, uninsulated electrodes, the ASTM-D-877 method should be used. Generally, the ASTM-D-1816 method is more responsive to dissolved water and particles in oil. If the tap changer has the selector and diverter switches in separate compartments, samples should be taken from both compartments.

The standards do not contain information on the recommended oil properties for load tap changers. However, the following guidelines can be used for general application. It is recommended that the manufacturer's information be checked carefully for this information before taking action since it may be critical to the operation and life of the tap changer.

Typical oil dielectric characteristics for load tap changers are as follows:

- Compartments with no insulated parts or well rounded electrodes:
  ASTM D 877 minimum dielectric = 25 kV
- Compartments with insulated parts such as cables or all electrodes are well rounded:
  ASTM D 1816 minimum dielectric = 20 kV

These conditions can be determined from internal inspections. If no inspections have been made, well-rounded electrodes are usually used in diverter switches above 34 kV. The manufacturer can also furnish such information.

5.4.5 Water In Oil Tests

There are a number of commercially available equipment to perform tests in accordance with ASTM-D-1533. The results of these tests are used to determine the water content in the transformers. The samples should be taken in accordance with ASTM-D-3613 requirements to prevent contamination of the sample with atmospheric moisture.

Maximum recommended water contents for different voltage classes taken from IEEE Std. 637 and C57.106 are listed in Table 5.5.

Table 5-5
Maximum Water-in-Oil Test

	Voltage Classes		
Test	**< 69 kV**	**69 – 230 kV**	**> 230 kV**
Water content, ppm max. at 60°C	35	20	12

5.4.6 Water Content of Paper Insulation

Water reduces the dielectric strength of paper insulation. The amount of reduction depends on the stress pattern (puncture or creepage), the thickness of the insulation, and other variables.

If excessive water exists in the insulation and the transformer is overloaded, bubbles can form at the hot surfaces that are in contact with paper having high water content. The formation of bubbles is risky if the transformer having wet insulation is overloaded and hot spot temperatures, such as 150°C, exist. Wet insulation is also a factor in maintenance and life extension since the insulation ages faster when it contains high levels of water. The water content of the paper can be estimated from the water in oil and the temperature of the oil as given in EPRI "Guidelines for the Life Extension of Substations" [4].

Table 5.6 provides the EPRI guidelines for maximum water content in paper insulation.

Table 5-6
Maximum Water Content

kV of Highest Voltage Winding	Maximum Water Content
525 and 800 kV	1%
230 and 345 kV	1%
115 up to 230 kV	1.5%
Less than 115 kV	2.0%

If the water content is in line with the above limits, no action is required. If the water content is marginal, it is recommended that off-line insulation power factor tests be performed to obtain a better estimate of the water content. If these values are exceeded, consideration should be given to drying of the insulation.

Periodic tests to check the internal condition of the transformer are recommended at an interval of three to seven years even if the results from other tests are found satisfactory. Insulation power factor tests are not usually performed during these intervals unless problems with bushings or other components make these tests desirable.

5.4.7 Oil Power Factor

This test is used as a check on the deterioration and contamination of insulating oil, due to its sensitivity to ionic contaminants. The percentage maximum acceptable values for power factor are taken from Reference 4 and are given in Table 5.7.

Table 5-7
Maximum Acceptable Percent Power Factors of Oil

	Voltage Classes		
Temperature	**< 69kV**	**69 – 288 kV**	**> 345 kV**
20° C	1.0	0.75	0.5
100° C	3.0	2.0	1.5

The power factor of oil is measured using ASTM D 924.

Power factors above the acceptance levels usually indicate the following:

- Excessive water content in the insulation
- Contamination of the insulation
- Failure within the insulation structure, which has deposited carbon on the insulation

If the power factors are greater than the above typical limits, consideration should be given to processing the oil using one of the procedures in IEEE Std 637, "Guide for the Reclamation of Insulating Oil and Criteria for Its Use," 1982 [8]. The use of activated clay to remove contaminants from oil is the preferred method by many utilities. It is recommended that some experimentation be performed before starting the processing. Some contaminants can be removed by filtering the oil with clean, dry cellulose filters. More expensive clay filtering needs to be used to remove other contaminants.

This test is a means for detecting oil-soluble polar contaminants and oxidation products in insulating oils. Higher values than those in Table 5.7 are indicative of measurable dielectric loss resulting in heat generation during transformer operation and insulation deterioration. It is generally recommended that the oil be processed if the values are greater than those in Table 5.7.

5.4.8 Oil Interfacial Tension

Values of interfacial tension (IFT) below the minimum recommended acceptance values shown in Table 5.8, taken from IEEE C57.106 [7], are normally the result of oxidation byproducts or chemical contaminants. If all other oil parameters are normal, interfacial tension values below those recommended are not of immediate concern. However, it is recommended that any downward trends be followed since it may indicate a deteriorating situation. The interfacial tension is measured in accordance with ASTM D 971. Table 5.8 shows normal recommended test intervals for transformers with no signs of abnormal condition. Transformers with signs of insulation deterioration would require sampling more often depending on the oil condition. In such a case, trending is necessary to determine how often samples should be taken and what other steps may be required such as load reduction or outage scheduling.

Table 5-8
Oil Interfacial Test

	Voltage Classes		
Test	**< 69kV**	**69 – 288 kV**	**> 345 kV**
Interfacial tension	24	26	30

If the oil interfacial values are below the acceptable levels given in Table 5.8 and there is a downward trend, the oil can be processed using the procedures in IEEE Std 637, "Guide for the Reclamation of Insulating Oil and Criteria for Its Use," 1982 [8].

5.4.9 Condition Monitoring Systems

Considering a large transformer system, the condition assessment process can be improved if some characteristics and properties of the transformer system are monitored by additional on-line sensors. Although transformers are a critical part of electrical generation and transmission systems, there was not a major emphasis on improved monitoring until the 1990s.

The emphasis on reduced maintenance costs and life extension makes it desirable to have on-line monitoring systems that provide information for determining when maintenance should be performed.

On-line monitoring systems are becoming more common in recent years. In some cases, on-line monitoring systems can provide continuous data without the requirement for oil samples and analyses. Such systems can also provide trending data and charts for further evaluation and assist in the decision-making process. The following sections cover transformer condition monitoring methods and current technologies. Off line diagnostic tests and monitoring devices are covered in Section 5.1.3.

5.4.9.1 Gas-In-Oil Sensors

The objective is to employ on-line gas-in-oil measurement methods that will determine the amount of fault gases in the oil. These sensors are mounted so that they are exposed to the oil and detect the following gases:

- Hydrogen
- Carbon Monoxide
- Carbon Dioxide
- Acetylene
- Ethylene
- Ethane
- Methane
- Oxygen

5.4.9.2 Temperature Sensors

Top oil thermometers are commonly used but some utilities use resistance temperature devices (RTDs) for improved accuracy and reliability.

The so-called winding temperature devices are used on a large percentage of power transformers. The sensor is a simulation device that responds to the top oil temperature and the heat generated in a resistance element. A bushing current transformer provides current proportional to the load current to the heating coil. The current adds an increment of temperature to the coil that is equal to the winding temperature rise above the hot oil temperature. They have limitations in that the setting depends on the hot-spot temperature calculated by the designer, which may or may not represent the true hot-spot, and the time response of the winding may be different than that of the device.

Winding temperature devices that are commercially available at present no longer use a resistor to determine the increment of temperature added to the top oil temperature. Instead, the increment is calculated by software.

Direct measurement of hot-spot temperatures using fiber optic technology was investigated in an EPRI Report No. 1000016, "Optical Fiber Acoustic Sensors for Inside Transformer On Line Detection of Partial Discharges," [9] and such sensors have been successfully installed in a number of operating transformers. The sensors are located in an area that is either the hottest spot location or is representative of the hottest spot temperature. The fiber optic cables are made from an insulating material and are not suitable for installation in the higher voltage regions. Therefore, sensors must be installed in a lower voltage area such as the low voltage windings or in leads. They can also be installed in the winding oil ducts to determine the hottest oil temperature since the winding oil duct temperature may be several degrees hotter than the bulk top oil temperature. The fiber optic cables are taken through pass-through devices to the outside of the tank where they are connected to read-out or recording equipment. The obvious advantage is that the actual hot-spot temperature can be determined for life extension considerations or for loading purposes.

5.4.9.3 Oil Level Gauges

Oil level gauges are used to determine the level under different temperature conditions and to alarm if the level is below the minimum such that high-voltage parts might be exposed.

5.4.9.4 Rate-of-Rise Relays

The sudden pressure or fault pressure relay detects sudden pressure transients produced within the transformer tank during operation. It senses the rate of change of pressure during internal faults. If the internal pressure exceeds the safe limits, the relay will activate the tripping scheme to de-energize the transformer. This relay does not act as a pressure relief device.

It should be noted that installation of rate-of-rise relays on older transformers may require some study. For example, some older transformers may have loose windings that cause hydraulic pumping of the oil under low-level short circuits or even during magnetizing in-rush, which can activate the relay. In such instances, persons familiar with the transformer design and the relay design should be contacted.

5.4.9.5 Gas Collector Relay

The relay collects free gas bubbles in the oil. The relay is connected at the top of the transformer tank to collect the generated gas. If the gas is generated by partial discharges, excessive heating, or arcs under the oil, an alarm is initiated by the relay. The relays will also respond to air bubbles caused by leaks.

5.4.9.6 Oil Pump Performance Sensors

There are three types of devices in use:

- Differential pressure oil flow indicators are used to determine when the pumps are in operation.
- Vane-type oil flow indicators are also used to determine when the pumps are in operation.
- Pump bearing wear detectors are available for pumps having sleeved bearings. These acoustic devices are used to determine any changes in the dimension of the gap between the shaft and the bearing surface. Base readings are obtained when the pump is new. A read-out device is then used periodically to determine if wear has occurred.

5.4.9.7 Load Tap Changer (LTC) Monitors

A number of load tap changer monitors have been installed on transformers. The basic principle is that contacts that are nearing the end of their life or that are coking generate additional heat, which raises the temperature of the oil in the compartment. The tap changer diverter compartment usually runs cooler than the main tank, and the selector compartment runs cooler than the diverter switch compartment. If the temperature of the diverter switch compartment starts to increase in comparison to the main tank or the selector compartment, there is usually a contact problem. If the selector and the diverter are in the same compartment, the temperature of the tap changer compartment must be compared to the main tank.

Many LTC overheating problems have been detected with infrared scanning and on-line monitors. The on-line monitors use temperature sensors located on the walls of the tap changer compartments and the main tank. The output is connected to recording and analysis equipment. Alarms can be activated if the temperature of the diverter compartment reaches a level indicating that the contacts should be inspected or changed. Other monitors that are available for load tap changers include:

- Timing circuits to determine if there has been a change in the operating time of the mechanical system.
- Measurement of the motor current including the starting current. Broken shafts or changes in the mechanical system might be detected.

Load tap changer monitors under emerging technologies include:

- Use of ethylene gas analysis to determine contact wear. It has been found that the change in the ethylene is different when contact heating occurs compared to the other gases generated when the tap changer operates. Some utilities are already experimenting with ethylene detection using chromatograph data.
- Acoustic analysis is being used in much the same manner as is being applied to circuit breaker monitoring.

5.4.9.8 Infrared Thermography

Infrared thermography can be used on bushings and other connections to help detect problems. Pumps and load tap changers running hot can also be identified. It is less effective on the overall transformer tank due to the volume of oil and thickness of the steel. However, some hot spots near the tank wall have been detected using this technique. It can also be used to verify correct operation of the cooling radiators. A consistent thermal gradient from top to bottom of all radiators should be observed. Internal blockages and valves in the wrong position have been detected in this way. It is recommended that thermography be performed on the following transformer components:

- Control cabinet internals and terminal blocks
- Tank
- Bushings and connections
- Surge arresters
- Load tap changers
- Coolers, pumps and motors

5.4.9.9 Water-In-Oil Sensors

The operation of water-in-oil sensors is based on thin-film capacitive element technology. The capacitance measured will change proportionally to the change in the relative saturation of water in the oil. The output of these devices is the percent relative saturation of the water in the oil, which is dependent on the temperature of the oil and the amount of water in the oil. If the temperature of the oil is known, the parts-per-million (ppm) of water can be determined. The best sensors incorporate a temperature measurement device at the tip of the sensor, ensuring that the correct ppm can be determined.

5.4.9.10 Partial Discharge Detection

Partial discharge detection is of great interest. If detected early, damaging conditions can be remedied, thereby reducing repair costs and preventing catastrophic failures. Partial discharge detection has been used in transformer manufacturing since the 1960s to determine the presence of damaging discharges during factory tests. It is recognized that such detection has reduced the number of field failures by detecting incipient problems and taking corrective action in the factory.

5.4.9.11 Acoustic Emission Devices

Acoustic partial-discharge detection is used in factories for location of discharges, and this technology has been developed for field detection. Acoustic signals are generated in the oil by partial discharges so that this method involves sensing of the acoustic signals that are transmitted through the oil. Acoustic signals are also generated by the formation of gas bubbles and can be used to locate sources of overheating.

Piezoelectric devices are used to detect acoustic emissions from the transformer internals and have been installed on the transformer to obtain more data or as on-line monitors.

5.4.9.12 Acoustic Sensors

A number of acoustic sensors are attached at different locations on the wall of the transformer. The output from the sensors can be taken to read out devices or recorders. Data may be recorded and diagnosed using a computer system. If the signals appear in a transformer that has had no signal or if there is an increase such that there is an upward trend, an alarm is initiated.

5.4.9.13 Internal Sensors

The piezoelectric sensor is attached to the end of a fiberglass rod and the rod installed in the oil. The output of these sensors is transmitted to a computer system for recording and analysis. Alarms are initiated when a signal originates in a transformer with no previous discharge history or if there is an upward trend. EPRI is currently developing a fiber optic acoustic sensor for mounting inside the transformer. Report number 1001943, "Development of a Prototype Fiber-Optic Acoustic PD Sensor: For Inside Transformer Installation," is available [26].

6
GENERIC AGING AND OBSOLESCENCE ASSESSMENT

This section addresses the steps numbered 11B and 11C in the LCM planning flowchart (Figure 2-1b). The intent is to help characterize the aging of passive SSCs, the wear of active components, and the obsolescence of SSCs. This characterization will serve to address the need for and timing of the replacement of large transformer equipment in the LCM planning process and to identify potential environmental conditions that affect the rate of degradation or require special plant-specific attention.

6.1 Aging Mechanism Review

An aging management review is an integral factor to LCM maintenance planning. The aging management program (AMP) for large transformers was reviewed and two documents were identified in the NRC NUREG-1801, Vol. II, Generic Aging Lessons Learned (GALL) Report [16].

- VI.A, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- VI.B, Equipment Subject to 10 CFR 50.49 Environmental Qualification Requirements

Sandia report SAND93-7068-UC-523 [19], "Aging Management Guidelines," provides important information on maintenance and surveillance of power transformers and specific information to investigate for each transformer component. It also provides signs to look for during inspection and analysis/interpretation of monitoring results. Visual inspection can be performed during routine walkdowns or during scheduled maintenance. In addition to the Sandia report, EPRI document TR106857, "Preventive Maintenance Basis Volume 38: Transformers (Station-Type, Oil-Immersed)" [3] and EPRI 186-401 "User Guide - Long Term Reliability Prediction of Nuclear Power Plant Systems, Structures and Components" [18] contain a wealth of information on large transformer aging. Information contained in these documents can be used to identify the effects of aging on various components of large transformers and appropriate aging management programs.

The recommendations for aging management programs are derived from these three documents and are presented here. This approach ensures that the results of the aging management review can be readily used, and allows the plant staff to become familiar with and adopt the terminology that has evolved in the industry with respect to aging management activities. The recommendations from the above three documents are extracted and presented in Table 6.1.

Table 6-1
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Aging Effect	Maintenance and Surveillance Techniques
Metal Enclosure (Tank) and Cover(s)	Rust, corrosion	Loss of wall thickness, metal cracks	Visual inspection of enclosure components and hardware; cleaning of exterior and interior enclosure surfaces (where accessible); painting of rusted or corroded portions of structure.
	Deterioration of seals or organic components (gaskets, seals)	Oil leakage, moisture intrusion	Visual inspection for embrittlement, cracking, or signs of fluid leakage; replacement as necessary.
	Metal fatigue	Structural integrity degradation	Visual inspection for missing screws, nuts, washers, and other fastening components; replacement as necessary.
Primary and Secondary Windings	Degradation of organic supports and spacers	Loss of separation between windings, clogging, impurities	Visual inspection of spacers, supports, and other insulating materials; insulation resistance testing; power factor testing; gas and oil evaluation.
	Formation of localized high temperature areas (hot spots)	Premature degradation of surrounding materials	Monitoring of hot spot, top oil, and other temperature indications; sampling and analysis of transformer insulating fluid for indication of decomposition byproducts and gases.
	Vibration, insulation degradation	Loosening of winding mounting systems, movement of windings in relation to one another	Frequency Response Analysis (FRA) test Visual inspection of winding mounting system for loose or damaged components; measurement of critical winding tolerances.
Magnetic Core	Core material embrittlement	Weakening or failure of lamination, increased eddy currents and core losses, insulation damage	Visual inspection for overheating or breaks in insulation/conductor; resistance and continuity testing.
	Loosening of core mounting system from design defects	Core dislocation, impact on fault current withstand, deterioration of insulation	Visual inspection of core mounting; core-to-ground test; measurement of critical core/winding tolerances.

Table 6-1 (continued)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Aging Effect	Maintenance and Surveillance Techniques
Insulation System	Dielectric breakdown of insulating fluid	Loss of dielectric strength, localized high temperatures in windings, combustible and non-combustible gases	Sampling and analysis for dielectric strength, power factor, water/impurity content, and combustible/non-combustible gases, as well as other analyses as applicable.
	Particulate and/or moisture contamination	Blockages, reduction in localized heat dissipation, reduction in dielectric strength	Visual inspection of insulating fluid for signs of impurities or water; dielectric strength and power factor testing; laboratory analysis for water content.
	High acidity	Deterioration and decomposition of solid insulating materials, insulation degradation	Sampling and laboratory analysis (neutralization number)
	Oxidation and sludge formation	Reduced efficiency of cooling system, increased acidity of insulating fluid	Visual inspection of insulating fluid; laboratory analysis for sludge and inhibitor content; maintenance of seals and airtight integrity of tank and oil preservation system components.
Bushings	Degradation of organic materials	Paper, gasket, and seal degradation	Power factor and capacitance testing.
	Contamination or deterioration of porcelain exterior surfaces	Formation of conductive path (tracking) along surface of rain shields, flashover	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning, coating, or replacement as necessary.
	Dielectric breakdown, bushing insulating fluid exposure to ambient conditions	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required.
	Improper strain on connection or mechanical stress, flashover	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain (outage). Thermography

Table 6-1 (continued)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Aging Effect	Maintenance and Surveillance Techniques
Cooling System	Motor, cooler fan, and pump wear	Bearing wear depends on type, frequency of lubrication, and service conditions. Undue vibration, friction, noise, loss of shaft tolerances.	Visual inspection of motors, fans, pumps. Periodic maintenance. Winding insulation resistance testing; replacement of motors and/or leads as required.
	Radiator, fins, tubes clogging	Reduction of heat dissipation	Visual inspection and cleaning of radiators, fins, tubes; verification of adequate air flow. Thermography
Load Tap Changers	Wear of mechanical components	Increased friction and accelerated wear	Visual inspection. Periodic adjustment and parts replacement as necessary based on inspection and maintenance.
	Wear of electrical components	Friction and accelerated wear of surface contacts	
	Thermal aging of insulating materials	Reduction of dielectric strength	
	Wear of main contacts		
	Deterioration of contacts	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level.
Sudden Pressure Relay (liquid only)	Thermal aging	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation; functional testing.
Bushing Current Transformers	Thermal aging	Degradation of organic insulating materials	Insulation inspection; insulation resistance testing.
Pressure Relief Devices	Thermal aging	Degradation of seals	Periodic testing for functionality; visual inspection for seal degradation
Temperature Indicators	Thermal aging	Failure of hot spot heating oil element	Periodic verification of temperature sensor functionality and accuracy.

6.1.1 Other Sources of Generic Failure Data

Failure data for components used in large transformers is presented in Table 3.1 of EPRI TR-106857-V38 [3], and is reproduced in Table 6.2. The data indicates specific transformer components, the degradation mechanisms, failure timing, and PM required to prevent such an event.

Table 6-2
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Transformer Oil (mineral)	Loss of dielectric strength	▪ Heat from normal operation	Continuous	Expect to be failure free for ~20 years Expect to be failure free for at least several years	Temperature monitoring DGA Partial DGA Oil dielectric test Oil screening Oil power factor testing	Oil screening DGA Operator rounds
		▪ Moisture ▪ Contamination (particulate)		Expect to be failure free for at least several years		
		▪ Low energy electrical discharge		Expect to be failure free for ~20 years		
		▪ Arcing	Random	Random on a scale of months		
Windings	Insulation breakdown	▪ Abnormal temperature rise	Random	Random, on a scale of 8 years at 90 C oil temperature or 110 C winding hot-spot temperature	Electrical tests: Power factor Turns ratio test Insulation resistance Oil analysis Thermography Vibration analysis Acoustic monitoring Gas blanket monitoring Oil testing for furfural Degree of polymerization of cellulose sample Partial discharge testing	Calibration and testing * Oil screening DGA Thermography Vibration/acoustic/ sound testing

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Windings (cont.)		▪ Moisture	Continuous	Expect to be failure free for several years		
		▪ Arcing	Random	Random on a scale of a month, can be rapid		
		▪ Aging: ▪ Heat of operation ▪ Corona	Continuous	Expect to be failure free for 40 years		
		▪ Partial discharge	Random	Random on a scale of several years		
		▪ Voltage surge		Random, depending on degree and number of events		
		▪ Oil quality	Continuous	Expect to be failure free for 5-7 years		
		▪ Mechanical losses	Random	Random		
Core	Loose	▪ Assembly of shipping error ▪ Vibration	Random and continuous Continuous	Expect to be failure free for 40 years, assuming oil is degassed as needed	DGA Vibration Sound level	DGA Vibration/acoustic/ sound Testing
	Loss of core ground	▪ Assembly or shipping error ▪ Vibration	Random and continuous Continuous	Expect to be failure free for 40 years, assuming oil is degassed as needed	Core ground testing	Calibration and testing
	Multiple core grounds	▪ Assembly or shipping error ▪ Vibration	Random and continuous Continuous	Expect to be failure free for 40 years, assuming oil is degassed as needed	DGA	DGA

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Core (cont.)	Shorted laminations	▪ Heat from over excitation or arcing ▪ Poor manufacturing ▪ Shipping or handling error	Random	Random, on a scale of years Random	DGA Turns ratio Single phase excitation current	DGA Calibration and testing
Gaskets	Leakage	▪ Aging from thermal cycling and stray eddy currents	Continuous	Expect to be failure free for about 20 years	Inspection	Operator rounds Engineering walkdown
		▪ Improper assembly ▪ Overpressure	Random	Random		
Tank	Corrosion	▪ Sulfur contamination	Random	Random on a scale of ~5 years, if tank is contaminated	Oil screening Sulfur test	No task
Oil Filled Bushings	Leakage	▪ O-ring failure	Continuous	Expect to be error free for at least 15 years	Inspection	Operator rounds Engineering walkdown
		▪ Over-temperature chipped or cracked porcelain ▪ Improper maintenance techniques	Random	Random		Bushing cleaning Maintenance inspection
	External contamination	▪ Environmental conditions	Continuous	Expect to be failure free for 2 to 5 years, depending on severity of conditions	Monitor a spare bushing Thermography Ultrasonic testing Audible noise Inspection	Thermography Operator rounds Engineering walkdown Vibration/acoustic/ sound testing Bushing cleaning Maintenance inspection

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Oil Filled Bushings (cont.)	Loss of BIL	▪ Internal contamination ▪ Operation above rating ▪ Low oil level ▪ Voltage surges (e.g. lightning strikes) ▪ Manufacturing techniques ▪ Improper maintenance ▪ Chipped or cracked porcelain	Random Continuous Random	Random	Electrical testing: Power factor Capacitance Inspection	Calibration and testing Maintenance inspection
Solid Bushings	Loss of BIL	▪ Chipped or cracked porcelain ▪ External contamination	Random	Random	Inspection Electrical testing: Power factor Capacitance	Maintenance inspection Calibration and testing
Lightning Arresters: (metal oxide varistor type)	Thermal runaway	▪ Aging	Continuous	Random	Electrical testing: Power factor Leakage current	Calibration and testing Lightning arrester leakage monitoring
No-Load Tap Changer	Misalignment, Contact Coking, etc.	▪ Wear and binding of mechanism ▪ Number of operations	Continuous	Random	Electrical testing Turns ratio test DGA	Calibration and testing DGA
	Sheared gear pin	▪ Binding of mechanism	Continuous	Random	Operation	No task
Load Tap Changer	Misalignment, Contact Coking, etc.	▪ Wear and binding of mechanism ▪ Number of operations	Continuous	Random	Timing test Turns ratio test DGA Thermography	Tap changer maintenance Calibration and testing DGA Thermography
		▪ Improper maintenance	Random			

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Load Tap Changer (cont.)	Damaged contacts	▪ Normal wear	Continuous	Expect to be failure free for > 100,000 cycles	Timing test Turns ratio test DGA Thermography Acoustic monitoring	Tap changer maintenance Calibration and testing DGA Thermography Vibration/acoustic/ sound level
		▪ Lack of use		Random, but could be a small number of cycles		
		▪ Oil quality ▪ Misalignment ▪ Improper maintenance	Random	Random		
	Leaks: gasket, piping and valves	▪ Aging ▪ Wear	Continuous	Expect to be failure free for 20 years	Inspection DGA	Operator rounds Engineering walkdown Tap changer maintenance DGA
	Motor operator failure	▪ Overload: linkage binding ▪ Exceeding duty cycle	Continuous Random	Random Random, on a scale of years	Operator counter Inspection	Tap changer maintenance Engineering walkdown
Fins and Tube Coolers (Oil Coolers	Airside fouling	▪ Air quality ▪ Debris	Continuous Random	Random Random, can be months	Inspection Oil temperature monitoring	Operator rounds Cooler maintenance Engineering walkdown
	Loss of heat transfer	▪ Internal oil sludging	Continuous	Expect to be failure free for 40 years	Inspection Oil temperature monitoring Thermography	Cooler maintenance Operator rounds Thermography
		▪ External corrosion		Expect to be failure free for 15-20 years		

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Fins and Tube Coolers (cont.)	Leaks: tube to header	▪ Thermal expansion ▪ Vibration ▪ Dissimilar materials ▪ Manufacturing defect	Continuous	Expect to be failure free for 40 years	Inspection	Operator rounds Engineering walkdown Cooler maintenance
			Random	Random, on a scale of 20 years		
	Leaking gaskets	Aging from thermal cycling and stray eddy current Improper assembly	Continuous	Expect to be failure free for about 20 years	Inspection	Operator rounds Engineering walkdown Cooler maintenance
			Random	Random		
	Dresser coupling leaks	Improper installation Improper design	Random	Random, can be immediate	Inspection	Operator rounds Engineering walkdown Cooler maintenance
Radiators	Airside fouling	Debris	Random	Random	Inspection Oil temperature monitoring	Operator rounds Cooler maintenance Engineering walkdown
	Loss of heat transfer	Low oil level	Random	Random, could be rapid	Inspection Thermography Oil temperature monitoring Oil analysis Loss of oil flow	Operator rounds Oil screening Engineering walkdown Thermography
		Oil sludging	Continuous	Expect to be failure free for 40 years	Inspection Thermography Oil temperature monitoring Oil analysis	Operator rounds Oil screening Engineering walkdown Thermography
Fans and Motors	Bearing wear	Age Excessive lubrication Lack of lubrication	Continuous	Expect to be failure free for 7 to 10 years	Vibration monitoring Motor current Thermography Acoustics monitoring Lubrication	Thermography Vibration/acoustic/ sound testing Cooler maintenance Motor current monitoring

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Fans and Motors (cont.)		Fan blade imbalance	Random	Random		
	Winding insulation failure	Age	Continuous	Expect to be failure free for 40 years	Insulation resistance	No task
		Water ingress at connections	Random	Random		
	Fan blade cracks	Fatigue Corrosion	Continuous	Expect to be failure free for 40 years	NDE Inspection	Cooler maintenance
		Imbalance Improper maintenance	Random	Random		
	Motor power cable deterioration	Age Heat Sunlight	Continuous	Expect to be failure free for 10-15 years	Inspection	Cooler maintenance
Pump and Motor	Bearing wear	Age	Continuous	Expect to be failure free for 40 years **	Vibration monitoring Motor current Bearing wear indicator Acoustics monitoring Ferrography	
	Impeller and volute wear	Age	Continuous	Expect to be failure free for 40 years	Vibration monitoring Motor current Acoustics monitoring Ferrography Flow indication	Vibration/acoustics/ sound testing Motor current monitoring Operator rounds Engineering walkdown
	Winding insulation failure	Age	Continuous	Expect to be failure free for 40 years	Insulation resistance	No task
		Water ingress connections	Random	Random		
	Motor power cable determination	Age Heat Sunlight	Continuous	Expect to be failure free for 10-15 years	Inspection	Cooler maintenance
Valves	Stem leaks	Aging Heat	Continuous	Expect to be failure free for 10 years	Inspection	Operator rounds Engineering walkdown

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Valves (cont.)	Disk detachment	Pin broken or dislodged	Random	Random	Operation	No task
	Bound or struck	Lack of use	Random	Random, on a scale of 10 years	Operation	No task
	Air In-leakage	Stem leak	Continuous	Expect to be failure free for 10 years	Oil pressure gauge Oil level DGA	Operator rounds DGA
Sudden Pressure Relay	Mis-operation	Age (switch, spring, and diaphragm)	Continuous	Expect to be failure free for 40 years	Functional test Replacement	Calibration and testing
		Vibrates loose Installation error	Random	Random		
Buckholtz Gas Volume Relay	Mis-operation	Installation error Maintenance error	Random	Random	Functional test	Calibration and testing
		Bound or broken linkage	Continuous			
Level Alarms	Mis-operation	Installation Maintenance error	Random	Random	Functional test	Calibration and testing
		Bound or broken linkage	Continuous			
Pressure Gauge	Drift	Age	Continuous	Expect to be failure free for 5-7 years	Calibration	Calibration and testing
Temperature Gauge	Draft	Drift	Continuous	Expect to be failure free for 4-6 years	Calibration	Calibration and testing
Conservator Tank	Bladder failure	Age	Continuous	Expect to be failure free for 40 years	DGA Inspection	DGA Maintenance inspection
	Fittings and connection leaks	Installation error Vibration	Random Continuous	Random Expect to be failure free for 40 years	Inspection	Operator rounds Maintenance inspection Engineering walkdown
		Stray eddy currents (at main tank connection)	Random	Random, on a scale of 2-3 years after occurrence		
Desiccant	Outlet breather valve fails to seal	Age Environment	Continuous	Expect to be failure free for 40 years	DGA	DGA
	Depletion	Moisture	Continuous	Expect to be failure free for a few years	Inspection	Operator rounds

Table 6-2 (continued)
Degradation Mechanisms

Failure Location	Degradation Mechanism	Degradation Influence	Degradation Progression	Failure Timing	Discovery/ Prevention Opportunity	PM Strategy
Gas Blanket Systems	Regulator failure	Drift Elastomer failure	Continuous	Expect to be failure free for 10 years	Inspection Alarm	Operator rounds Engineering walkdown
	Leaking: pipes, tubing, fittings, gaskets and valves	Age Vibration	Continuous	Random	Inspection Alarm	Operator rounds Engineering walkdown
Relief Valve	Improper operation	Age Corrosion	Continuous	Random	Inspection Alarm	Operator rounds Engineering walkdown
Electrical Connections	Loose	Vibration Thermal cycling	Continuous	Random	Inspection Thermography	Maintenance inspection Thermography
Control Relay	See EPRI Report TR 106857, Volume 30, Relays-Control					See EPRI Report TR 106857, Volume 30, Relays-Control
Timing Relay	See EPRI Report TR 106857, Volume 31, Relays-Timing					See EPRI Report TR 106857, Volume 31, Relays-Timing
Motor Starters, Breakers, and Transfer Contactors: Wiring, Fuses, and Lights	See EPRI Report TR 106857, Volume 8, Low Voltage Electric Motors (600V and below)					See EPRI Report TR 106857, Volume 8, Low Voltage Electric Motors (600V and below)

Note: The above Table 6.2 (Ref. 3) is reproduced from EPRI's TR-100806 report. The following comments are offered to clarify items not clearly listed.

* Calibration refers to testing equipment.

** Pumps and motors are not expected to be failure free for 40 years. (See Section 5.2.2.1.)

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6.2 Expected Lifetimes of Major Components

In addition to long-term aging of passive components, active components of large transformers are susceptible to wear or degradation. This degradation must be addressed by routine preventive maintenance, including overhaul and component replacement. Typical failure timing for active transformer components is presented in Table 6.2, together with information on degradation influence and cause. It should also be noted that the maintenance (corrective or preventive) entailed in replacing worn out components can be addressed through the maintenance programs identified in Section 5.4, considering the failure rates discussed in Section 4.1.2.1 (Table 4.1).

6.3 Technical Obsolescence

Guidance is provided using the evaluation method provided in Table 2.2 of the Life Cycle Management Sourcebook Overview Report [1].

Many systems in a nuclear power plant (and in particular those with electronic instrumentation) are susceptible to technical obsolescence. Components may have to be replaced because of the unavailability of spare parts. In these cases, the likelihood and timing of the need to perform replacement of the system or components will be determined by the failure (or degradation) rate of the part, and availability of spares from other sources. The feasibility and cost of reverse engineering the obsolete components should also be considered.

To ascertain whether a given system is susceptible to technical obsolescence, the evaluation method provided in the Life Cycle Management Sourcebook Overview report [1] (shown as Table 6.3) can be applied as a first step. Using the criteria from this table emphasizes the seriousness of technical obsolescence for the following reasons:

- There are very few transformer manufacturers left in the voltage class of 138 kV and higher.
- Tertiary winding loading demands a new design.
- UATs and RATs/SATs are two, three, and in some cases four winding type transformers which require special design to accommodate the physical configuration of the windings in the same tank. Some transformer manufacturers decline to build multiple winding transformers and utilities often have no choice but to find overseas manufacturers and pay the added shipping cost.
- The bushing arrangements for GSUs and UATs are unique because of isophase bus connections.
- Bushings are long lead components and replacing them requires an outage. Therefore, planning and scheduling is essential to avoid unnecessary plant shutdowns and loss of revenue. In some cases, older bushings may not be available and additional engineering tasks may be required.
- Special design is required to account for generator characteristics and sudden load drop during a turbine trip.

- Special insulation design is required for a delta connection on the HV side.

These characteristics do not lend themselves to an immediate delivery when required. It may be worthwhile to quote SOER 02-3 (19) as follows:

- Many original equipment manufacturers are no longer in business and many stations are depending on other transformer vendors for service and technical support.
- The unique design of each transformer contributes to difficulty in sharing and learning from industry experience.

This aspect of obsolescence should be addressed in developing LCM alternatives. Table 6.3 identifies an example of the application of obsolescence evaluation for a cooling fan.

Table 6-3
Application of Obsolescence Evaluation Criteria for a Cooling Fan

	Technical Obsolescence Evaluation Criteria	Score	Yes
1.	Is the SSC still being manufactured and will it be available for at least the next five years?	5.0	
2.	Is there more than one supplier for the SSC for the foreseeable future?	3.0	
3.	Can the plant or outside suppliers manufacture the SSC in a reasonable time (within a refueling outage)?	3.0	
4.	Are there other sources or contingencies (from other plants, shared inventory, stock-piled parts, refurbishments, secondary suppliers, imitation parts, commercial dedications, etc.) available in case of emergency?	3.0	3.0
5.	Is the SSC frequency of failure/year times the number of the SSCs in the plant time the remaining operating life (in years) equal or lower than the number of stocked SSCs in the warehouse?	3.0	
6.	Can the spare part inventory be maintained for at least the next five years?	3.0	
7.	Is the SSC immune to significant aging degradation?	1.0	1.0
8.	Can new designs, technology, concepts be readily integrated with the existing configuration (hardware-software, digital-analog, solid-state, miniaturized electronics, smart components, etc.)?	3.0	3.0
9.	Is technical upgrading desirable, commensurate with safety and cost effective?	3.0	
	Total Obsolescence Score:		7.0

Ranking Guidance for Table 6.3

- Total score is < 6.0, RED and the SSC obsolescence is serious. Potential options to deal with obsolescence and contingency planning should be identified. Guidance on the modeling, timing and costs of these contingencies, and the associated risks should be provided.
- Total score is between 6.0 and 10.0 YELLOW, and the SSC may have longer term concerns for obsolescence. Contingency planning and options should be considered.
- Total score is > 10, GREEN and the SSC is not likely affected by obsolescence.

The score of 7.0 for the example component in Table 6-3 indicates that contingency planning and obsolescence mitigation options should be addressed in one or more alternative LCM plans.

7
GENERIC ALTERNATIVE LCM PLANS

This section addresses steps 12-17 in the LCM planning flowchart (Figure 2-1b) to provide guidance for developing alternative plans. The EPRI LCM Demonstration Program Report [2] summarizes alternative LCM plans as follows:

> *"Following the assessment of aging and reliability, potential alternative LCM plans should be identified. The objective here should be to explore whether there are potentially better ways of addressing the aging management of the SSC. These inputs can come from plant staff but input should also be solicited from outside experts and industry benchmarking projects."*

The following guidance for these steps includes the identification of possible plant operating life strategies and the development of alternative LCM Plans that are compatible with or integral to the strategies identified. Also provided is a hypothetical illustration of alternative LCM plans (for large transformers) with the attendant discussions of the logic for building the alternatives and the derivation of assumptions.

7.1 Plant Operating Strategies and Types of LCM Planning Alternatives

The determination of LCM planning alternatives will be driven mainly by the plant operating strategies that, implicitly or explicitly, are being followed or evaluated and the current reliability performance of large transformers and component parts. Accordingly, the LCM planning alternatives that will be evaluated are very plant-specific. The typical plant operating strategies and standard approaches to LCM planning alternatives are discussed below.

7.1.1 Plant Strategy 1: Operate the plant for the currently licensed period of 40 years.

This strategy requires minimizing risk during the remaining operating period until the plant's license expires and identifying limiting SSCs which could result in premature power reduction or replacements forcing an economic decision regarding early decommissioning. LCM plan alternatives that might be developed under this strategy include:

- **LCM Plan Alternative 1A:** A base case to determine the cost of the activities performed under the current maintenance plan, and assuming that the activities will continue as-is until the end of the licensed plant life. This case also assumes the ***continuation of the existing maintenance program*** without any major capital investments, unless absolutely necessary.

- **LCM Plan Alternative 1B:** An alternative plan in which the current maintenance plan is optimized and ***an aggressive PM program*** is implemented to reduce equipment failures, lost power production, and regulatory risk.
- **LCM Plan Alternative 1C:** An alternative in which the current maintenance plan is optimized and ***older transformers are refurbished/replaced*** with more reliable equipment. Variations to this alternative are schemes such as:
  - Transformers with larger temperature rise boundaries
  - Consideration of a three-phase unit in one tank against three-single-phase units in three separate tanks, or three-phase half size, in two tanks
  - Refurbishment of the transformer by retaining the core
  - Additional radiator cooler banks or chilled water system

7.1.2 Plant Strategy 2: Operate the plant for 60 years under a License Renewal Program

This strategy recognizes the potential for license renewal and extended operation of the plant. Major investments will be required to achieve extended operation. These investments can only be justified by additional revenue generated in the additional 20-year operating term. LCM planning alternatives that might be considered under this strategy include:

- **LCM Plan Alternative 2A**: A rigorous preparation for license renewal with an aggressive aging management program, system performance enhancements, and timely component replacements or upgrades. This LCM plan recommends timely replacement of like-for-like components such as pumps, fans, motors, level and temperature indicators, etc.
- **LCM Plan Alternative 2B:** Preparing for eventual license renewal with an aggressive PM and PdM program, but delaying plans for major capital improvements until the actual extended license is implemented (i.e., in year 35 of the plant life).

7.2 Development of Detailed Alternative LCM Plans

For each alternative LCM plan proposed, detailed maintenance activities and schedules need to be identified. Each plan will involve some mix of the LCM approaches in steps 13 to l7 in Figure 2-1b. This section will provide guidance in developing the alternative LCM plans. The following may be considered when developing the alternative LCM plans:

- Adjusting the frequency of time-directed maintenance activities to enhance the reliability of the large transformers or reduce maintenance costs.
- Considering diagnostics (PdM) to convert from time-directed to condition-directed maintenance.
- Performing preventive and non-invasive maintenance activities on-line, if feasible.
- Adding routine preventive and predictive maintenance activities that might enhance the reliability of large transformers. A number of these activities are listed in Section 4.1.5.

- Tasks that are specifically devoted to transformer aging. While many of the routine maintenance tasks performed on or proposed for large transformers might broadly be regarded as being intended to address aging, a number of tasks are identified in Table 6.1, "Common Maintenance Issues and Surveillance Techniques," of Section 6 that specifically address the aging of passive components. The addition (or deletion) of these tasks should be considered in alternative LCM plans.

- Tasks that address, facilitate or enable operating changes to minimize or equalize component wear. For example, the flow of oil into the bottom of the winding can be modified and optimized by changing the sequence of pump activation to avoid high flow into the bottom of any phase. This reduces static electrification and increases reliability. By staging the pumps as shown in Table 7.1, efficiency can be optimized. Installation of run-time meters and start counters can help ensure pumps are run equally, thus avoiding excessive wear on any one pump. Start counters also facilitate the scheduling of time-directed maintenance for active stand-by equipment.

Table 7-1
Guide for Staging of Pumps on Forced-Oil-Air (FOA) Transformers

No. of Pumps	Group 1	Group 2	Group 3
3	1	1	1
4	1	1	2
5	1	2	2
6	2	2	2
7	2	2	3
8	2	3	3

7.3 Hypothetical Illustration of Assembling LCM Planning Alternatives

This section illustrates the process of creating LCM planning alternatives. A hypothetical case is discussed with assumptions identified.

The recent improvements in the design of oil-filled transformers have been in the technology of better insulation characteristics. New insulation has allowed transformers to be built to operate at higher temperatures, voltages, and with larger tanks. The transformer life is guaranteed only if the insulation is preserved in conjunction with the mechanical components like bushings, LTC, accessories, and the cooling system. During the life of a transformer, all components undergo wear and aging due to operating conditions. If the unit is operated within its nameplate ratings with minimal tap change operations, transformers should operate for the design life.

Many of the components like LTCs, bushings, accessories, pumps, coolers, etc., can be replaced once a faulty condition is detected. These are reversible life components which, when replaced in a timely manner, will help to extend the life of the transformer. However, there is one major component of the transformer that, once subjected to abnormal condition, cannot be restored to its original condition -- it is the transformer solid insulation.

The transformer solid insulation degradation is an irreversible event. Once aging begins, it is an irreversible degradation process, which determines the life of the transformer. Therefore, the preservation of the transformer insulation is of paramount importance for preserving the life of the transformer. The oil that is used to remove the heat also serves as a part of the insulation scheme.

All transformers undergo some kind of aging, but the older large transformers need special attention. Replacement of these transformers is not easy because the original manufacturers may no longer be in business, particularly in the voltage class 138 kV and higher. Therefore, this case is not a hypothetical situation but a very real threat. Apart from requiring a higher voltage rating, the large utility transformer requires special terminal arrangement, matching transformer and generator characteristics, higher BIL, and customized reactance matching.

Based on this unique situation, alternatives must be in place for continuous plant operation. When preparing the alternative LCM plans the following may be considered:

- Review original design with an objective of "fit-for-service" status (items such as BIL and short circuit capability).
- Analyze the system disturbance, impact on the transformer (e.g. through-faults, lightning strikes, frequency and voltage swings).
- Consider monitoring the loading very closely.

The following items may be considered as LCM planning progresses:

- A spare GSU, UAT or RAT/SAT is a prudent investment for plants that have one of each of these transformers. Maintaining a spare for half-size GSUs in large power plants may not be as critical since half of the generating load can be carried with one transformer. However, considering the revenue losses for the time to repair or receive a new transformer, the cost for maintaining a spare is small.
- Power plants with two auxiliary transformers per unit may have the flexibility to carry all the station auxiliary power loads with one transformer if the other UAT is out of service. Of course, the load carrying capacity depends on the size of the transformer. Some newer plants have GSUs, UATs, and RATs/SATs with additional excess capacity.
- Table 7.2 provides a sample cost analysis and the process of creating LCM planning alternatives. The inspection, maintenance, and repair frequencies as well as the cost associated with these tasks are approximate numbers. The effort here is to provide a hypothetical illustration that can be followed as an example when actual costs are known in order to choose the best alternative.
- Labor hours used in the hypothetical illustration are different for daily and monthly inspections. Monthly inspections involve more detailed tasks.
- Labor charges may be higher for outside contractors compared to in-house personnel. Outside contractors may not be as well informed as in-house personnel regarding plant-specific equipment.

Table 7-2
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
1.1	Inspection									
1.1.1	Daily	1	1	60		365	21,900	21,900	21,900	21,900
1.1.2	Monthly	1	2	60		12	1,440	1,440	1,440	1,440
1.1.3	Daily	1	1	60		365	21,900	21,900	21,900	21,900
1.1.4	Monthly	1	2	60		12	1,440	1,440	1,440	1,440
1.2	Calibration (every 18 months)									
1.2.1	Protective relays	10	8	60		0.5	2,400			
1.2.2	Sudden pressure	1	4	60		0.5	120			
1.2.3	Pressure relief	1	4	60		0.5	120			
1.2.4	Indicators (temp. & level)	6	16	60		0.5	2,880			
1.2.5	Gas accumulator	1	8	60		0.5	240			
1.2.6	Protective relays	10	8	60		0.75		3,600	3,600	3,600
1.2.7	Sudden pressure	1	4	60		0.75		180	180	180
1.2.8	Pressure relief	1	4	60		0.75		180	180	180
1.2.9	Indicators (temp. & level)	6	16	60		0.75		4,320	4,320	4,320
1.2.10	Gas accumulator	1	8	60		0.75		360	360	360
1.3	Oil sampling									
1.3.1	Oil sampling	1	4	60	200	1	440			
1.3.2	Oil sampling	1	4	60	200	2		880	880	880

Table 7-2 (continued)
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
1.4	Thermography									
1.4.1	Thermography	1	4	60	100	1	340			
1.4.2	Thermography	1	4	60	100	2		680	680	680
1.5	Maintenance									
1.5.1	Radiators/coolers	16	8	60	500	1	8,180			
1.5.2	Radiators/Coolers	16	8	60	500	2		16,360	16,360	16,360
1.5.3	Motor fans	24	8	60	500	1	12,020			
1.5.4	Motor fans	24	8	60	500	2		24,040	24,040	24,040
1.5.5	Oil pumps	4	16	60	1000	1	4,840			
1.5.6	Oil Pumps	4	16	60	1000	2		9,680	9,680	9,680
1.5.7	Conservator tank	1	16	60	1000	0.33	653			
1.5.8	Conservator tank	1	16	60	1000	1		1,960	1,960	1,960
1.6	Repairs									
1.6.1	Oil pumps	4	32	80	1000	1	11,240			
1.6.2	Oil pumps	4	32	80	1000	0.5		5,620		
1.6.3	Oil pumps	4	32	80	1000	0.25			2,810	2,810
1.6.4	Oil pump rebuild	4	40	80	10000	0.25	5,700			
1.6.5	Oil pump rebuild	4	40	80	10000	0.1		2,280		
1.6.6	Oil pump rebuild	4	40	80	10000	0.05			1,140	1,140
1.6.7	Fan motors	4	30	80	5000	0.25	3,650			
1.6.8	Fan motors	4	30	80	5000	.1		1,460		
1.6.9	Fan motors	4	30	80	5000	0.05			730	730

Table 7-2 (continued)
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
1.7										
1.7.1	Pump replacement w/ efficient with minimum 15 year bearing life (cost includes drain oil)	4	80	80		One time		90,000		
1.7.2	Fan motors	12	8	80		One time		8,000		
1.7.3	Bushings (cost includes drain oil)	6	160	80		One time		77,000		
1.8										
1.8.1	Repair old transformer on site	1	180	80		One time		95,000		
1.8.2	Remove old transformer (cost includes material & equipment)					One time			110,000	110,000
1.8.3	Repair old transformer at the factory (includes transportation)					One time			950,000	
1.8.4	Install old transformer					One time			1,500,000	
1.8.5	Install new transformer (cost includes transformer cost, material & equipment)	1	800	80		One time				5,300,000
2.1	Other									
2.1.1	Lost Power generation ($250,000 per day) (Note 1)					0.2	1,200,000			
2.1.2	Lost Power generation ($250,000 per day)					0.1		600,000		

Table 7-2 (continued)
Hypothetical Example for Single Tank, Single Unit, 3-Phase Transformer

Item #	Activity Description	No. of Comp.	Labor Hours	Labor Cost ($)	Mat. Cost ($)	Frequency/ Year	Alt. A Existing Maintenance Program	Alternative B Partial Upgrade & Aggressive PM Program	Alternative C Refurbishment & Aggressive PM Program	Alternative D New Transformer & Aggressive PM Program
2.1.3	Lost Power generation ($250,000 per day)					0.05			300,000	
2.1.4	Lost Power generation ($250,000 per day)					0.03				180,000
2.2	Regulatory Cost Per Year						25,000	10,000	4,000	2,000
	Total Recurring Cost						1,314,503	728,280	417,600	295,000
	Total One Time Cost						0.0	270,000	2,560,000	5,410,000

Note: A Lost Power Generation $250,000/day * 24 days (estimated replacement/repair time)*0.2=$1,200,000

8 GUIDANCE FOR ESTIMATING FUTURE FAILURE RATES

This section addresses a part of step number 18 of Figure 2-1b. Failure rates are a main driver of the LCM planning process.

General guidance for estimating SSC future failure rates can be found in Section 2.6 of the LCM Sourcebook Overview Report [1]. The following are some useful ideas for estimating failure rates in the large power transformer LCM planning studies.

- Table 6.2, Degradation Mechanisms, provides the estimated "Useful Life of Components." This data may be used to estimate the expected remaining life of the transformer components. If "in-kind" replacements are made, existing failure rates may be applied for the future.
- Plants that have a transformer performance trending program can extract transformer failure data and compute failure rates for the large transformers. Data can be plotted to determine the effects of aging and if the current PM programs are effective.
- Large transformer failures likely to result in a plant trip or a reduction in power are due to transmission system disturbances, LTC failure, transformer temperature escalation beyond design temperature limit, and transformer accessory failures.
- In addition to the above, more than 30% of the EPIX reported failures were due to human or maintenance errors. When evaluating and determining plant-specific failure rates, human errors and maintenance errors need to be included in the basis.
- Corrective work orders provide a means of reconstructing the transformer failures and to compute failure rates. The WO review should encompass at a minimum the last five years of data to generate meaningful results.
- Failure rate reductions can be achieved by replacing accessories such as oil pumps, motors, and fans that exhibit frequent breakdowns or failures. If the LCM plan considers such accessory replacements, future failure rate projections must consider the effect of replacement as discussed in the LCM Sourcebook Overview Report [1].
- When transformer accessories such as motors or pumps are replaced with a similar model from a different vendor, the failure rates may be different. A reasonable projection is to use the existing failure rate until a new failure rate can be determined (based on failure rate trending), unless the vendor has reliable data to support a different rate.
- The subject transformers although non-safety-related, provide power to safety-related equipment. Transformer failure may not trigger an immediate trip or scram, but will require entry into a Limited Condition of Operation (LCO). Various time limits are established from

a few hours to seven days based on the time estimated to repair the failed transformer or its accessories. Failure to repair or replace the failed equipment and return to operational status within the time limit requires steps for plant shutdown.

- Routine maintenance task tickets and corrective work orders provide failure cause information of transformer components and accessories. Such information can be used to establish the base case. Probabilistic Risk Assessment (PRA) based failure rates may be used in projecting future transformer failure rates and its components and accessories.
- The PRA based failure rates for transformers are likely expressed in demand failures (or reliability), if the transformer is in stand-by service. These values can be converted to failure rates, if the annual demands (actual and tests) are known. If the transformer is normally operating, its performance is likely modeled as availability or the inverse unavailability, expressed in hrs/hr of service. To convert this to a annual forced outage rate, multiply the value by 8760 (hours per year) to obtain the expected (probable) annual out-of-service rate to be used for lost power generation calculations.
- When the plant-specific PRA is used as a basis for the plant-specific system failure rates, verification of the basis for the PRA input should be considered.
- If plant-specific transformer failure rates are not readily available from plant databases, the plant-specific PRA may be a source of reliability values for use in LCM planning. See above method to convert reliability values (demand failures) to annual failure rate. Establishing a comprehensive transformer and accessory performance trending program is an important step in LCM planning.
- Transformer failure rates from Section 4.0 (Table 4.1) can be used in the absence of a performance trending program. If no plant specific failure data exists or is of questionable accuracy, it would be reasonable to assume an average industry failure rate (over the last 11 years) of about 0.10 per year as a starting point in the LCM analysis. The absence of transformer failures could be verified by reviewing the Trip/Scram reports for the plant. Transformers that are more than 20 years old (>50% of their design life) will experience a higher failure rate due to aging and the high end of the industry-wide failure rate would apply (0.15 per year).
- Table 6.2 provides the failure timing of the major components for transformers. This information can be used to project possible remaining life of a component or to plan for transformer replacement.

In summary, failure rate predictions for plant-specific transformer components are made using the above specific guidance and the generic guidance presented in Section 2.6 of the LCM sourcebook overview report. PRA and Maintenance Rule records may be an important source of information. The LCM planning process should be fairly complete with carefully defined specific activities for each of the LCM alternative plans. In this way, the influence of new or additional PM activities, implementation of replacements, and redesigns can be appropriately considered in estimating future failure rates for input to LCM economic evaluations.

9
PLANT-SPECIFIC GUIDANCE FOR ECONOMIC MODELING

This section addresses the cost prediction portion of step number 19 in the LCM planning flowchart (Figure 2-1b).

In this large transformer LCM sourcebook, generic cost data is presented below from the INPO data and should be corrected for the individual plants, given the variations in equipment types and sizes and plant-specific accounting practices.

Table 4.1 shows a total of 119 transformer failures in U.S. plants over a period of 10 years (1991 to 2001). With 104 operating plants, this averages to about 0.11 failures per year per plant, 40 of the events (or about 33.6%) caused a plant shutdown for an average of 9 days (for a 1000 MW plant this equates to 10 million dollars).

Therefore, for an individual plant, the potential annual cost in lost power production from a transformer failure based on the industry average (at $50 per megawatt hour) is:

0.11 x 0.336 x $ 10,000,000 = $ 400K

This value may be of use when considering implementation or corrective actions capable of reducing the failure probability.

When developing alternatives, it is best to formulate plans that are relatively simple and do not include massive changes at one time. A step-wise approach will provide simplicity and retain overview of the plan. For instance, a first step from the base case would be the conversion to a more effective preventive maintenance program for the transformers, including oil analysis, thermography, and failure trending. The additional costs and savings can then be determined for the remaining life of the plant and the impact on transformer failure reduction can be illustrated.

Although the initial cost for an aggressive PM program is high, reduction in failure rate of transformers and components will offset the cost as equipment and plant outages are reduced. Section 3.8 of the LCM Planning Sourcebooks Overview Report [1] contains a generic discussion and listing of the typical financial data to be collected and specified as input to the economic evaluations of alternative LCM plans.

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