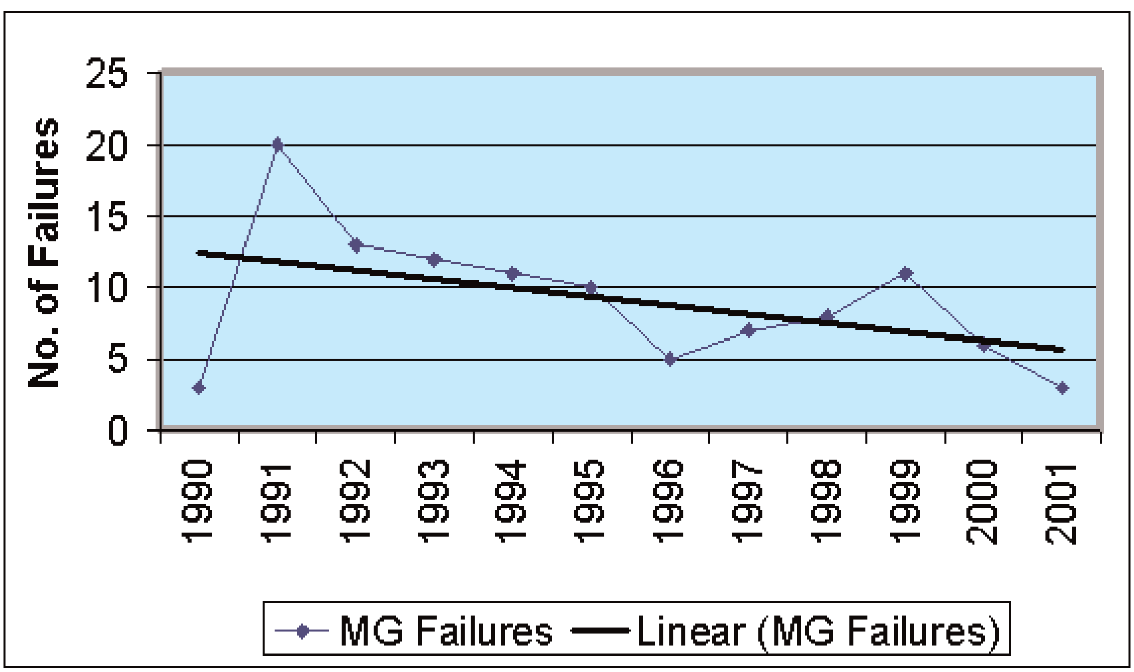
Life Cycle Management Planning Sourcebooks

Volume 5: Main Generator

Technical Report



Life Cycle Management Planning Sourcebooks

Volume 5: Main Generator

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Final Report, July 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 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 main generators.

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 a long-term equipment reliability plan for their plant-specific SSC (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 generic information, data, and guidance typically needed to produce a plant-specific LCM plan for main generators.

Approach
Experts in the maintenance and aging management of generator systems followed the LCM process developed in EPRI’s *LCM Implementation Demonstration Project* (1000806). The scope of the physical system and types of components in the study was defined. Information and data on historical industry performance of selected types of main generators within this scope were compiled; technical guidance for using this information is presented as a starting point for preparing plant-specific main generator LCM plans. EPRI LCM utility advisors reviewed this sourcebook prior to its publication.

Results

This sourcebook contains information on main generators, including their exciters and voltage regulators. It also contains information on accessories and monitoring devices for turbine generator protection and performance. Information includes performance monitoring issues, component aging mechanisms, aging management maintenance activities, equipment upgrades, and replacements. The sourcebook includes an extensive list of references, many of which are EPRI reports related to the maintenance and reliability of main generators.

EPRI Perspective

This report should enable preparation of plant-specific plans for main generators 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 author. Using this sourcebook, system engineers need only add plant-specific data and information to complete an economic evaluation and LCM plan for the plant's main generator. 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 sourcebook revisions.

Keywords

Life cycle management
Nuclear asset management
System reliability
Component reliability
Main generator
Turbine generator

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MANAGEMENT SUMMARY

This Life Cycle Management (LCM) Planning Sourcebook for a Main Generator (MG), including its Exciter and Voltage Regulator, will help guide your plant engineers or expert consultant in preparing a life cycle management plan (long-term reliability plan) for your plant-specific generator and exciter components. The generic information and guidance presented in the sourcebook is expected to help plant engineers focus on areas where there may be significant opportunities for cost-effective improvements in long-term plans. Also, it may reduce the cost of preparing your plant-specific LCM plan for generator and exciter by about a third compared to starting from scratch.

Guidance consists mainly of

- generic information, data, and references,
- industry-wide MG issues and ways to ensure that they are addressed at your plant,
- MG component aging mechanisms together with the maintenance activities to manage them,
- generator, exciter and voltage regulator obsolescence issues and available management options, and
- alternative LCM plans that can be considered during long-term planning for the MG critical components.

This sourcebook provides a hypothetical LCM plan to illustrate plant-specific application. 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 long-term planning for emerging obsolescence issues can be developed.

Important reasons for covering MG components in a sourcebook are that (1) high reliability of the main generator systems is important to economic plant operation, (2) at many plants, significant MG reliability gains are available through optimized maintenance processes, and (3) some of the critical components within the MG exciter controls and voltage regulators will become obsolete within the next ten years and will be no longer supported by original equipment manufacturers' (OEMs) or aftermarket suppliers. MGs will require replacement, substitution or technological upgrades of some obsolete components, particularly for plants contemplating license renewal.

The industry reliability issues for MGs identified by this study are:

- Failures are significant contributors to lost power generation and plant trips. The MG failure rate causing unit outages is about one failure per 10 years per generator, as calculated from failures reported to NPRDS/EPIX.
- Most MG problems emanate from generic design problems, assembly errors, and lack of recognition of gradually developing aging degradation.
- Failures of major MG components require long repair times. Availability of major spares reduces unit outages to component change-out times instead of repair or purchase order times.

The main technical obsolescence issue for MG components is:

- The analog technology used in exciter and voltage regulator circuits is obsolete and many replacement parts are no longer available. Some OEMs no longer support the originally supplied components.

The candidate approaches for formulating MG LCM plans as alternatives to the current ("baseline") plan include:

- Implementation of on-line monitoring and diagnostic systems (such as temperature and vibration monitoring, partial discharge testing of generator winding, and detection of rotor shorted turns) and fine-tuning of preventive maintenance (PM) procedures.
- Optimizing the major and minor inspection and testing procedures for assessment of the condition of main MG components.
- Various replacement options, such as replacement of generator stator and rotor windings, new rotors, new or upgraded exciters, and transition to digital controls with redundant circuits.

2 LCM SOURCEBOOK INTRODUCTION

2.1 Purpose of LCM Sourcebook

This Main Generator LCM Sourcebook is a compilation of the generic information, data, and guidance an engineer typically needs to produce a plant-specific LCM plan for a generator and its principal components, such as stator, rotor, exciter and voltage regulator. It must be recognized that not all generic information in a sourcebook applies to every plant. However, its applicability may be determined by benchmarking the generic data against plant-specific experience. The data may also show indicators or precursors to problems not yet experienced at a given plant. Caution and guidance is therefore provided in the plant-specific guidance sections (Sections 5, 8, and 9) 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 [1] and six plant-specific Main Generator LCM plans for the STARS alliance plants (Callaway, Comanche Peak, Diablo Canyon, Palo Verde, South Texas Project and Wolf Creek). LCM planning reports for the STARS plants are available in CD form [2].

2.2 Relationship of Sourcebook to LCM Process

The process steps for LCM planning are described in detail in the EPRI LCM report [1]. The LCM planning flowchart in Figures 2-1 to 2-3 of this Sourcebook are essentially the same as Figure 1-1 to 1-3 of [1]. The flowchart was modified only to improve clarity with respect to aging management and technical obsolescence (e.g. Step 11 has been subdivided into three distinct tasks). The chart is segmented into the four elements of the LCM planning process: System, Structure, Component (SSC) Categorization/Selection, Technical Evaluation, Economic Evaluation, and Implementation.

2.3 Basis for Selection of Turbine Generator for LCM Sourcebook

The Main Generator was selected for preparation of a sourcebook by the EPRI LCM Advisory Committee members. The main reasons for its selection were

- It is applicable to all plants, BWRs and PWRs
- It is important to power production
- It is subject to significant degradation and obsolescence of components
- It requires significant and costly maintenance

Using an initial listing of important systems, structures, and components (SSCs), the sourcebook candidates were ranked in accordance with the average priority given by LCM Advisory Committee members and considering generic applicability, SSC importance for power production and safety, potential for degradation and obsolescence, and concern for maintenance.

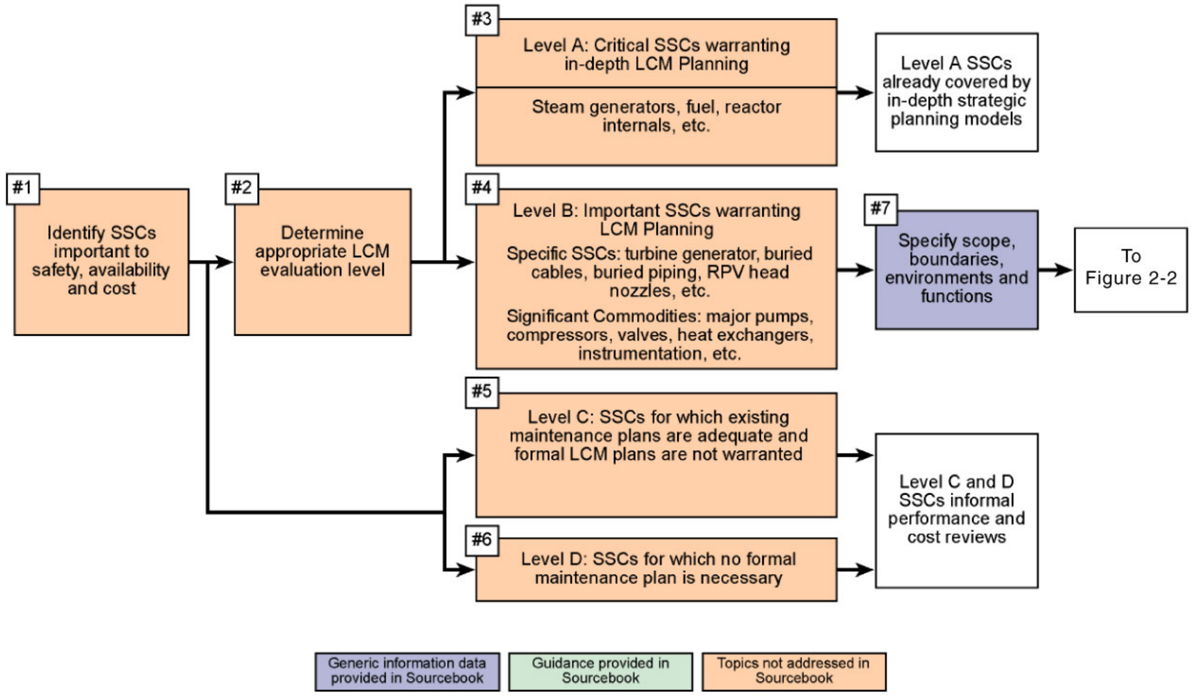

Figure 2-1
LCM Planning Flowchart – SSC Categorization and Selection

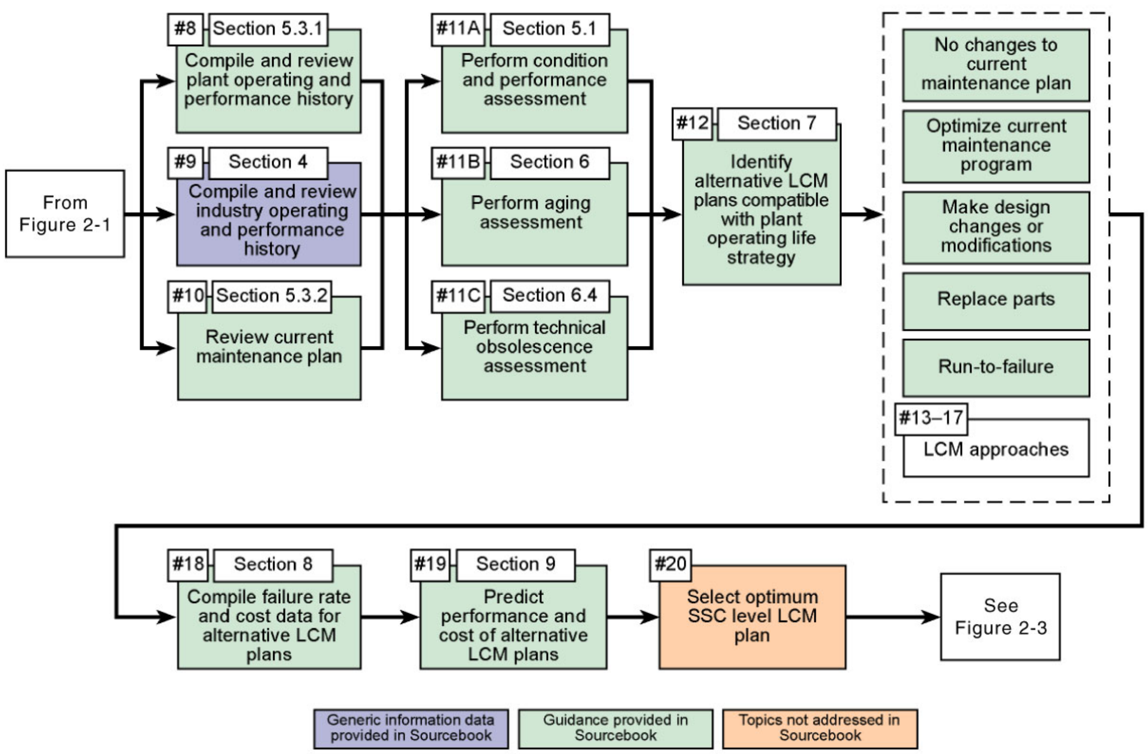

Figure 2-2
LCM Planning Flowchart – Technical and Economic Evaluation

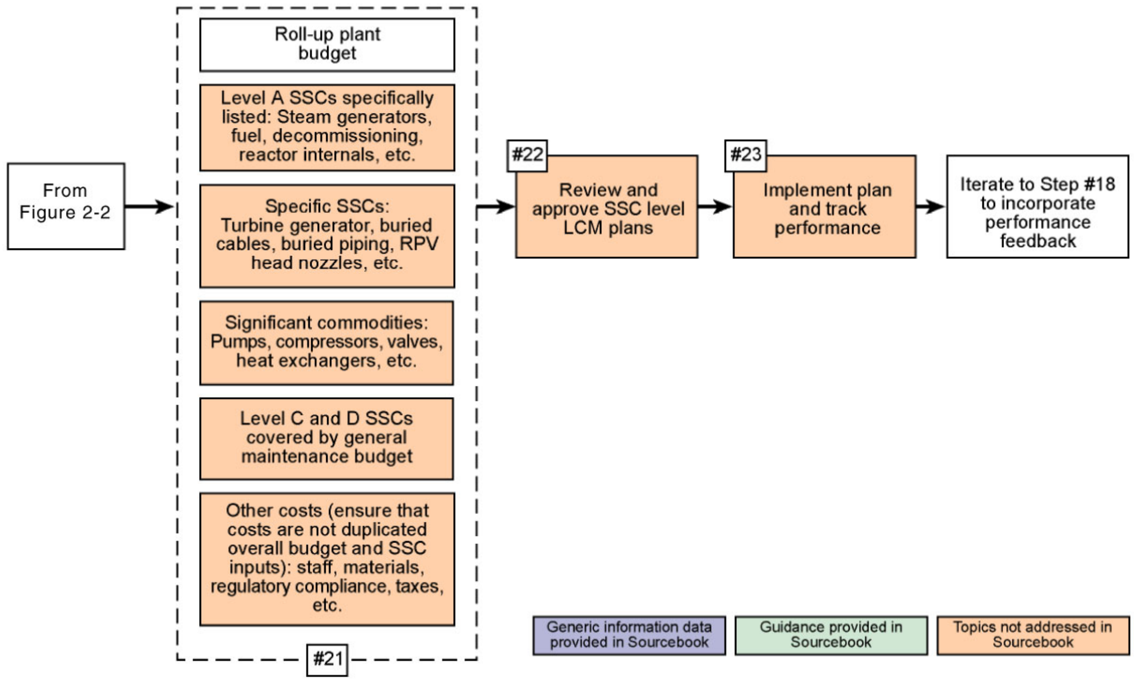

Figure 2-3
LCM Planning Flowchart – Implementation

3 BACKGROUND INFORMATION

This section addresses step number 7 in Figure 2-1.

The main unit generator converts the mechanical energy received in the form of torque and speed at the turbine generator coupling into electrical energy in the form of MVA, delivered at the generator terminals. This generator sourcebook is applicable to BWR and PWR nuclear power plants, as the generator design is not a function of the primary heat energy parameters.

3.1 Safety and Operational Significance

A generator, in itself, is not directly related to plant and personnel safety. However, generator trips due to sudden faults may have some effect on plant safety by causing unscheduled reactor scrams and associated challenges to the safety systems.

Generation of electric power is the primary mission of electric power plants. Therefore, plant economics are largely and directly affected by the generator availability, forced outage rates, repair rates, planned maintenance outage requirements and maintenance costs.

Generator rotors, typically with a mass of 100 to 200 tons rotating at 1800 rpm, have great kinetic energy. A disintegration of a generator rotor could produce flying debris, since it is not likely that all rotor mass could be contained within the generator casing and the debris could be a risk to plant personnel safety. A disintegration would almost always destroy the generator. Such events have been recorded. Generators contain hydrogen gas under pressure for cooling of rotor windings and stator core. Hydrogen purity is normally maintained at levels above 98% to prevent formation of explosive mixtures with air. However, in-service events of hydrogen explosions and hydrogen fires have been recorded. The risk of such events is higher during gas purging operations, should strict procedures for filling/purging not be observed or equipment failures occur.

3.2 Generator Function

The function of a generator is to generate electric power, at rated voltage and frequency, to be delivered to the electrical power grid and consumers. This is accomplished by conversion of mechanical energy, delivered to the generator rotor from the steam turbine, into electrical energy by means of electro-magnetic induction. This energy is delivered in MVA, or in MWe at the appropriate power factor, as measured at the main generator terminals, and allowing for the plant power requirements.

The main objectives of generator maintenance and aging management are:

- Maintain high generator reliability and availability for power generation.
- Ensure generator life expectancy to be comparable to other main unit components, such as turbine, steam generators and reactor.
- Ensure generator capability at optimized reactor and turbine outputs.

For proper functioning of the generator the following auxiliary systems are utilized: excitation system, hydrogen gas control system, seal oil system and cooling water system for direct cooling of stator winding (and rotor winding for a few plants).

The function of the excitation system is to provide controllable magnetizing current to the rotor winding. This control is obtained by fast acting automatic voltage regulators, which maintain the generator output voltage in step with the power system. The main generator components (stator winding, stator core and rotor winding) require enhanced cooling in order to maintain the temperature rises of electrical insulation within acceptable thermal limits and to prevent excessive thermal aging. Hydrogen gas under pressure is used for cooling of the stator core and rotor winding. To contain the hydrogen within the generator casing, hydrogen seals are required to prevent gas leakage along the rotating shaft. The hydrogen seals require continuous supply of clean degassed oil. This oil is supplied to the seals by a separate auxiliary, which includes oil pumps, filters, coolers, along with associated pressure and flow controllers. The supply and pressure control of the hydrogen gas is furnished by a separate gas control system. This system also contains a circuit for supply and control of inert gas, normally CO_2, used for purging of the generator casing during gas filling and purging operations. Purging is required for separating hydrogen gas from air and avoiding the formation of an explosive mixture of hydrogen and oxygen.

The stator windings contain hollow conductors, through which flows de-mineralized water. This water removes the thermal losses generated in the winding, thus maintaining the winding insulation temperature within design limits. A separate auxiliary system supplies the de-mineralized water to the winding in a closed recirculating loop. The system includes a tank, pumps, filters, coolers, strainers, flow and pressure controllers. A deionizer and a conductivity cell are normally also included.

3.3 Generator Critical Components and Component Boundaries

Generators with all their components, including exciters, hydrogen-cooling auxiliaries, winding water cooling auxiliaries, seal oil detraining and pumping unit, are normally supplied under an overall turbine and generator contract. Although the design details can vary significantly between manufacturers, the main generator components are readily recognizable and degradation and failure mechanisms are similar.

Steam turbines and turbo generators at nuclear power plants are in most cases 1500/1800 rpm for 50/60 Hz systems, respectively. In generators, this results in 4 pole rotors and multi-circuit layout of the stator winding. The phase-to-phase voltage ratings are in the range of 18 to 26 kV, selected by suppliers for balanced and economical machine design.

This sourcebook covers the generators supplied from the following manufacturers:

- General Electric (GE)
- Westinghouse (W)
- Allis Chalmers
- Siemens
- ABB (Brown Boveri)
- Alstom (English Electric, GEC)

Due to the design, function and operational similarity of main generators, the information presented here will be a useful reference for other main generators, not specifically addressed in this sourcebook.

The most critical components in each main generator are stator winding, stator core, rotor and exciter with voltage regulator. All generators addressed by this sourcebook contain these components. The detailed design and manufacturing processes differ from supplier to supplier and these variations often determine the specific generic sensitivities, which affect the in-service performance of generators. The operating practices, recognition of developing problems, and maintenance policies/practices have a decisive impact on generator performance. The critical components of the main generator are described below:

Stator winding. Stationary components, mechanically secured within the core slots and in the end winding support structure. The conductors are made from low resistance copper strands. A mix of solid and hollow strands are assembled in bars and insulated with polyester/epoxy-mica insulation, rated for 18 to 28 kV, depending on design layout. Critical parameters affecting winding life are: maintaining operating temperatures within the thermal limits of winding insulation and preventing insulation abrasion from relative vibration motions at winding supports. The stator windings are normally direct water-cooled, using de-mineralized water arranged in closed loop re-circulating flow through hollow strands in bars, using an external heat exchange and pumping auxiliary system. Many types of degradation can be detected and recognized with suitable on-line monitoring systems, such as temperature monitoring, water or hydrogen leak detection, and trending of partial discharges.

Stator core. Provides a low reluctance path for the magnetic flux required for induction of the voltage in the stator winding, minimizing eddy current losses and resultant heat. This flux is generated in the rotor by the rotor windings and passes through the air gap between the rotor and stator core and closes from pole to pole through the stator core. The core consists of thousands of magnetic steel laminations, a third to a half millimeter thick, electrically insulated from each other. The laminations are assembled in a steel rod/bolt cage at the core outer perimeter and axially clamped with suitable core clamping plates. Some designs also have steel bolts through holes in the core for additional clamping. Critical parameters affecting the core life are:

1. Maintaining the core temperature within the limits of core insulation class, and
2. Maintaining the core clamping pressure above the level at which lamination vibrations would lead to lamination cracking and breaking from the core.
3. Prevention of over-fluxing the core that would breakdown the insulation between the laminations resulting in high eddy current and stator core melting.

Monitoring of core temperatures by embedded sensors and detection of severe overheating by core monitors provide some information about core condition. Off-line tests are required to identify remedial actions.

Rotor. Consists of a solid forging made from magnetic alloyed steel, and copper windings assembled in slots machined in the forging and secured in slots by steel, bronze or aluminum wedges. At each end strong retaining rings to prevent copper breakage due to centrifugal forces must support the winding coils. The rotor winding, arranged in four-pole configuration, is supplied with DC excitation current, creating a strong magnet. The turbine drives this rotor magnet at 1800 rpm thereby inducing the voltage in the stator windings. The magnetic field density distribution on the rotor surface ensures a sinusoidal shape of the stator winding voltage at 60 Hz frequency. A common issue with rotors is the exposure of the winding copper and insulation to high centrifugal loads and thermal expansion forces, leading to breaks in the winding insulation and to copper cracking and dusting. Other problems affecting rotor life are crack formations in the stress concentration regions of the forging, winding wedges, and retaining rings. Although less common, the consequence and risk from such events can be serious. Some rotor winding problems are readily recognizable from on-line monitoring for shorted turns and from indication of winding ground faults. Interpretation of shaft vibration signatures can detect thermal instabilities, shaft rubs, shorted turns, and shaft crack propagation.

Exciter. Provides regulated DC current to the rotor winding. Fast response exciters are normally specified to provide stable unit response to power changes on the power grid. The main generator voltage is maintained within operating limits by the automatic voltage regulators (AVR) in the exciter circuit. Manual and automatic voltage regulation channels are normally supplied. An additional power stabilizer may be used to enhance the excitation response and improve system stability.

The generators covered in this sourcebook have several exciter designs:

- A generator shaft driven brushless exciter, with rotating diode rectifier; a permanent magnet generator (PMG) provides power to the AVR and exciter.
- A generator shaft driven exciter with static non-controlled rectifier and shaft-mounted sliprings.
- A generator shaft driven exciter with static controlled rectifier (SCR) and shaft-mounted sliprings.
- Transformer-fed (potential-source) SCR exciter and shaft-mounted sliprings.

The reliability record of excitation systems is generally good. The designs are robust, having spare capacity and redundancies to meet the high response and high ceiling, or field forcing voltages. However, the control circuits contain a large number of components and circuit cards that fail at some frequency and sometimes cause unit outages and/or deratings. Additionally, the rapid technological advances in solid-state devices, programmable controllers, and software driven data acquisition and control systems since the 1970s have rendered many exciter sections technologically dated or obsolete. The sources of replacement parts and support services are declining or no longer available for preventive or corrective maintenance. Wholesale replacement of exciters may be required in the future, if units are operated much beyond their initial design life.

For the above components the failure and repair rates can be evaluated from past performance data in the industry. The future performance can also be estimated from specific design data, specific machine operating experience, and past maintenance/repair records. It is estimated that they contribute 90-95% of the generator failure rates and associated repair and outage costs.

Since the remainder of the generator components contribute less than 10% to the generator outage and repair rate, they are bundled together for the purpose of evaluation of past and future cost streams. Should plant-specific circumstances warrant special consideration for a MG component (e.g. hydrogen seals, bearings, casing, etc.), then, given its extraordinary contribution to unreliability, its performance and costs need to be evaluated separately in LCM planning.

3.4 Scope of Equipment Covered by this Sourcebook

The scope of this sourcebook consists of the following generator components:

- Generator frame or casing
- Stator winding, including phase connections and winding support system
- Lead extensions and terminals
- Stator core, or magnetic core
- Rotor winding, including copper conductors and insulation system
- Rotor forging, gas-circulating fans
- Retaining rings
- Bearings
- Hydrogen coolers
- Hydrogen seals
- Slip rings
- Exciters; rotating exciters with rotating diode rectifiers; rotating exciters with static rectifiers; static exciters with controlled thyristor rectifiers, Generex (GE) exciters,

Boundaries of the generators in this sourcebook are:

- Generator rotor coupling flange at turbine end, excluding flange bolting
- Generator frame footing, excluding bolting
- Piping flanges to auxiliary packages (service water to hydrogen coolers, winding cooling water, bearing and seal oil piping, hydrogen and purging gas piping)
- Generator neutral and phase terminals, including neutral connections (but not phase flexible leads to Isolated Phase Bus)
- Electrical terminals in generator junction boxes
- Interface between bearing pedestal and base plates (for generators with pedestal bearings)

- Exciter, including rotating alternator, rectifier, gate pulse generator, AVR, and exciter breaker (if supplied), is included. Also included are generator current transformers (CT’s) and potential transformer (PT) cubicle. For static exciters, the termination point is at the high-voltage terminals of the excitation supply transformers.
- Local instrumentation and monitoring (sensors and functions only)

Excluded are turning gear, generator auxiliary packages (hydrogen supply system, stator winding cooling water system, seal oil system), rotor cooling water system, and exciter water cooling system. It is considered that these are lower-level SSCs for which existing maintenance is adequate so that no additional life-cycle planning is necessary.

4

INDUSTRY OPERATING EXPERIENCE AND PERFORMANCE HISTORY

This section addresses step number 9 in the LCM planning flow chart in Figure 2-2.

The information in this section will be used for comparison or benchmarking to plant-specific conditions and operating experience. It will also be used to identify potential plant-specific aging and failure mechanisms. The *qualitative* data is intended as a checklist of potential conditions affecting plant-specific performance, while the *quantitative* failure data will provide insight into the potential for plant enhancements and help to identify where improvements can be made. If plant-specific component failure rates are much less, say by a factor of three, than those indicated by the generic industry data, it can be concluded that the existing maintenance plan is very effective and further improvements difficult to achieve. On the other hand, reliability greater than the industry's may indicate excessive costly maintenance, which could be relaxed and still maintain high reliability. Similarly, equipment refurbishment/replacement or major changes to maintenance practices may be required if the plant-specific component failure rates are substantially higher than the generic rates presented here, or if the contribution of the generator/exciter system significantly exceeds that experienced at U.S. nuclear plants. In other words, if the reliability of an SSC falls below a certain level, replacement or major maintenance efforts will be required, if only to satisfy the Maintenance Rule performance criteria.

It should be noted that this section addresses failure rates 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 plant-specific Mean Time To Repair (MTTR) will have an impact on the system availability and plant productivity. MTTR may be a worthwhile subject for benchmarking by the industry.

4.1 Nuclear Industry Experience

An extensive review of the available industry experience with generator performance has been conducted. The review of failure mechanisms on generator components covers large generators and exciters rated above 450 MW that have been in service at both nuclear and fossil plants since about 1970. The failure data and forced outage data, however, have been evaluated only for generators at nuclear plants. No distinction is made for PWR or BWR plants, as these generator designs are not affected by the primary heat source. All nuclear plants in the United States have 1800 rpm turbine generators; this defines the basic design parameters of generators and provides a common base for comparison of their performance.

4.1.1 NPRDS/EPIX Data

The main source of generator and exciter failure data was records available through NPRDS and its successor EPIX. The NPRDS/EPIX data covered generator performance over the past 12 years; during this period most generators were in a mature state with respect to their reliability statistics (i.e. infant mortality failures were not observed). The NPRDS data available was dated from 1990 to 1996 and the EPIX data from 1997 to 2001. From the event descriptions it was possible to determine the generator and exciter components causing the failure and, in most instances, the outage duration or power loss values. The generator and exciter failure distribution over the 12-year period is shown in Figure 4-1.

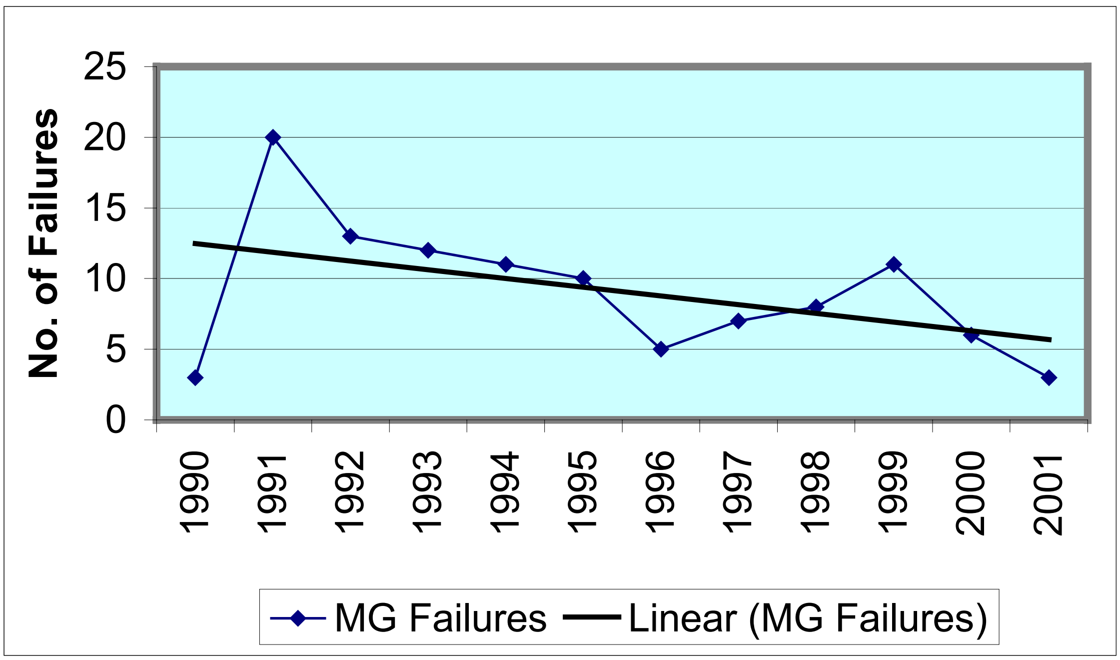

Figure 4-1
Generator and Exciter Failures 1990 – 2001 NPRDS/EPIX Data

The declining trend of failures illustrated in Figure 4-1 indicates that generator performance has been improving since the resolution or management of certain earlier problems; for example, water leaks and winding vibrations. The five-year EPIX data confirms that a stable failure rate can be expected within a population of mature machines. The average failure rate of a generator within the population is approximately 9.1 failures/year. This failure rate consists mainly of random events that are not preventable by maintenance. Normal aging and developing failure mechanisms would be detected and corrected by on-line and off-line testing, inspections, and repairs during minor and major generator and exciter outages. Therefore, we believe that the average rate will remain fairly constant in the future.

It should be noted that EPIX data also provided reliable data on failure modes, their descriptions, and planned generation loss in MWH, but did not provide outage durations. From the information on the generation losses and unit rating, the estimates of repair times were calculated, assuming unit operation at full power. The available generator and exciter failure data were analyzed as shown in Table 4-1.

These data are from 65 of 104 generators and exciters at 46 nuclear plants in the United States. Although much of generator PM and CM is completed during reactor fueling outages, the number of forced outages and forced extensions to planned outages is still considerable. The data indicates the dominant contribution of four main generator components to the unit downtimes and associated losses to power production; namely, stator winding, rotor winding, rotor forging and attachments, and the excitation system with voltage regulator.

Several runs of data from NPRDS/EPIX were reviewed, three by Comanche Peak staff and one by EPRI. As some differences were noticed between the run results, the above results are a consolidation of all the runs. In addition, it appears that some under-reporting, mislabeling, or loss of data may have occurred in databases (some known events did not appear in some of the outputs). Therefore, the calculated industry average failure rates may be somewhat lower than the average of actual U.S. industry-wide experience. Comparison of plant-specific data to the industry average may therefore appear more unfavorable than in actual fact.

There is a notable absence of stator core problems. Core failures are very infrequent. However, if and when they do occur, core failures can keep a unit out of service for a period of at least two years given that no spare or replacement stator is available.

The generator failure rate was calculated from 115 forced failure states on the 65 generators and exciters that reported failures over the 12-year operating period. The failures were distributed over the entire 104 operating nuclear units, presuming that the plants missing from the tally in Table 4-1 had no reportable failures. The failure states include forced outages (FO), forced extensions to planned outages or refueling outages (FEPO), and forced power de-ratings (FD) converted to equivalent forced outage days.

The failure rate is calculated from failure states divided by the number of generators and the operating period in years:

Failure Rate = Failure States/Number of Generators in Population/Operating Years

Failure Rate = 115/104/12 = **0.092 failures per year**

This calculated generator failure rate is valid for the whole generator system, including auxiliaries. In the NPRDS/EPIX data there were only a few reported generator outages from auxiliary cooling systems for the examined period of 12 years. Although these systems are not within the direct scope of this study, these failures have been included in the overall failure rate. This practice is consistent with failure rates from other databases, as will be shown in Sections 4.1.2 to 4.3.

Table 4-1
Generator and Exciter Failures from NPRDS and EPIX 1990 – 2001

Component	Aging	Design, Fabrication	Human Error	Foreign Object	Set Point Calibration	Vibration	Coolant Leak, Gas Leak	Maintenance	Total	Outage Days
Stator winding	3	2	1	1	3	3	7	0	20	458
Stator core									0	0
Rotor winding	2	1		1		1	2		7	143
Rotor forging, fans and RR's				1		1	2	1	5	170
Hydrogen coolers					1		2		3	21
Hydrogen seals					1		1	3	5	39
Bearings	2					2		5	9	26
Exciter	7		1	2	7	3	4	9	33	170
Voltage regulator	7	1		1	3				12	22
Terminals, bushings						1	3		4	21
Brush gear	1	1	1			2		2	7	13
CT, PT	1	1	1			4		3	10	38
Total	23	6	4	6	15	17	21	23	115	1120

The failure rates for generator components (Table 4-1) have been calculated and are shown in Table 4-2. These can be used for comparison to plant-specific data and for identifying components that may need individual attention during maintenance planning.

Table 4-2
Generator Component Failure Rates Calculated from NPRDS/EPIX Data

Component	Failure Rate (failures/year)
Stator winding	0.0160
Rotor winding	0.0056
Rotor forging, fans, RR	0.0040
Hydrogen coolers	0.0024
Hydrogen seals	0.0040
Bearings	0.0072
Exciter	0.0264
Voltage regulator	0.0096
Terminals, bushings	0.0032
Brush gear	0.0056
CT, PT	0.0080

The generator forced outage rate (FOR) has been calculated at 0.31% at a plant capacity factor of 0.8, or 0.27% at a plant capacity factor of 0.9. The generator forced outage frequency (FOF) is 0.24 regardless of capacity factor. The FOR is calculated from all forced outage hours divided by the sum of forced hours and service hours. The FOF is derived from all forced hours divided by period hours, e.g. 8760 for hours in a year. These parameters can be used as a benchmark against plant-specific performance data, as well as for comparison to other data sources.

Calculations:

Forced outage hours per unit per year = 24 hours/day x 1120 days/12 years/104 generators = 21.5 hours/year/generator

FOR = ([forced+ forced extensions + de-rating] hours)/ (all forced hours + service hours)x100

FOR = 21.5/(21.5+7000) = 0.31 %

FOF = ([forced+ forced extensions + de-rating] hours)/ hours per year)

= 21.5/8760 = 0.24 per year

The yearly service hours were estimated from Generation Availability Data System (GADS) data, which indicated a service factor for nuclear units of about 0.75, or 6570 hours, for the years 1991-95. The service factor has recently begun to improve increasing to 0.8, or 7000 service hours/year. Service factors of 0.9 have been achieved on some units. The value of 7000 hrs/year was used in the above calculations.

From Table 4-1, the average generator forced outage time due to a failure is 1120 outage days over 115 events, or 9.74 days (234 hours) per event. The average cost of Lost Power Generation at a power price ranging from $25 to $50 per MWH for unplanned capability loss ranges from 5.8 to 11.7 million dollars per event for a 1000 MWe plant. The annual risk therefore is the failure rate of 0.092 times the event cost, or about one half to one million dollars for a 1000 MWe plant.

It is suggested that the NPRDS/EPIX data be used as a reference in plant-specific failure rate evaluations. The data below for other populations of generators were not accounted for in forecasts for the U.S. nuclear power population. They are presented only for comparison to EPIX data as an indicator of the effectiveness. of the generator PM and CM practices implemented at U.S. nuclear power plants.

4.1.2 NERC/GADS Nuclear Units

The North American Electric Reliability Council and Generation Availability Data System Publications (NERC/GADS) Generating Availability Report provide data on 125 nuclear units (104 U.S. units and 21 Canadian units) and, as well, on most large fossil units in the U.S. Most of the information is based on the performance of a whole generating unit, rather than by components and systems. However, some of the reliability parameters, such as forced outage rate (FOR), forced extensions to planned outages (FEPO), and forced extensions to maintenance outages (FEMO) are calculated for the generator and other main components of a generating unit.

For nuclear units, the GADS Availability Report for a 5-year period, 1991 to 1995, gives the generator forced outage rates listed in Table 4-3 and Table 4-4. All generators in this group have 4 pole rotors rotating at 1800 rpm; most have direct water-cooled stator windings, direct hydrogen-cooled rotor windings; and hydrogen-cooled stator cores. Note that the rates are adjusted to include the forced extensions of planned and maintenance outages to make them comparable to those calculated from the NPRDS/EPIX data.

In Table 4-3 the generator forced outage rates are presented for different generator rating groups. There are significant variations in the generator FOR of the different groups. Such variances are attributed to differences in generic problems that develop on different designs and their effect on generator failure rates. Also, in smaller populations of machines any significant problem will dominate the whole group and skew the results. Comparison of generators at CANDU units to those at PWRs and BWRs provides interesting insight; since CANDU units do not have refueling outages, there is less opportunity to perform maintenance activities concurrently with scheduled outages. The generator contribution to unit outages thus becomes more frequent and causes longer downtime.

The results in Table 4-3 may be useful to users who would prefer to use data on generators that are rated closer to their specific machines rather than the more general averages calculated from the NRPDS/EPIX data.

Table 4-3
NERC/GADS Generator Forced Outage Rates by Generator Groups

Reactor Type	Number of Units	Unit-Years	NERC/GADS FOR by Generator Groups
PWR 400-799 MW	12	52	0.04 %
800-1000 MW	24	117	0.37 %
1000 MW +	35	173	1.11 %
BWR 400-799 MW	4	20	0.45 %
800-1000 MW	13	65	0.73 %
1000 MW +	15	75	0.42 %
CANDU 500-900 MW	21	100	1.03 %

Table 4-4
NERS/GADS Adjusted Forced Outage Rates for Nuclear Units

Units	Number of Units	NERC/GADS Adjusted Forced Outage Rate
All Units, all sizes	125 Nuclear Units	0.71 %
PWR Units	71 Units	0.67 %
BWR Units	33 Units	0.53 %

Table 4-4 summarizes the NERC/GADS Adjusted FOR on all nuclear power generators in the U.S. and Canada. There is a 25% difference in generator FOR between the PWR and BWR units. The reason for this 25% difference was not identified in this study. These generator forced outage rates are substantially higher than the 0.31% FOR calculated from NPRDS/EPIX reports. It is not clear what is causing the difference. Perhaps one cause is that some forced outages, as well as unit service hours, reported in GADS were not captured in the NPRDS reports.

4.1.3 Canadian Electrical Association (CEA)

The CEA Generation Equipment Status Annual Report covers commercial generating units from 15 public and private utilities in Canada. The 1995 report reflects the operating statistics of 854 generating units: 687 hydraulic, 95 fossil, 22 nuclear, 39 combustion turbine and 11 internal combustion (Diesel) units.

The five-year data analysis on 22 nuclear units is presented here for comparison to NPRDS/EPIX results.

The 22 units accumulated 103 unit-years over five years at an overall operating factor of 77.18. The generator failure rate of 0.38 and derating adjusted forced outage rate of 0.55% were calculated. This is significantly different from the GADS reported generator FOR of 1.03% shown above. This reflects the difficulty in dealing with different reporting systems and vetting of data used in the analyses. It is considered that the result obtained through the CEA is closer to reality and more comparable to the NPRDS/EPIX results than the GADS data. Comparing CEA results with NPRDS/EPIX results confirms that the generator reliability is comparable when similar maintenance programs and performance monitoring criteria are used.

4.1.4 Maintenance Rule Requirements

The Maintenance Rule requires identification, trending, and reporting to EPIX of Maintenance Preventable Functional Failures (MPFFs) and, more importantly, repetitive MPFFs. The review of Maintenance Rule events can provide much information and data to be used in plant-specific reliability assessments of generator systems, such as component identification, problem description, corrective action, unit outage and de-rating indication, and outage duration. Generator and exciter systems are not categorized as risk-significant systems and are normally monitored by plant-level criteria. The reason for this is that a generator or exciter system failure could cause a plant trip or de-rating, or trigger a safety system. Frequent and extended generator outages would exceed the plant-level criteria and move a generator/exciter system to A-1 status. This status would require goal setting and monitoring to demonstrate that the corrective actions were implemented and effective.

4.2 Generic Communications and Other Reports

4.2.1 NRC Generic Communications

The NRC Information Notices, O&M Reminders, and Licensee Event Reports, as well as INPO Operating Experience Reports and Serious Event Reports (SER's), have also been reviewed. These cover much the same events as reported in NPRDS/EPIX, but with a different emphasis. With respect to generator events, they provide significant detailed descriptions of failure modes. These reports do not identify any generator failures in addition to those captured in EPIX and thus do not add any data to the generator failure rates calculated in this study.

4.2.2 Vendor Communications

Most generator suppliers (OEMs) inform their clients of common problems with the generator that are experienced in-service and reported by customers. These problems are often related to specific models or groups of machines only and may not be experienced by all clients. Examples of such feedback systems are the Technical Information Letters by General Electric Co. or the Customer Information System by Siemens-Westinghouse. These reports contain proprietary information on the type of problem, inspection, and test procedures used to detect them and remedial action required to repair the problem(s). Changes to operating and maintenance procedures may also be recommended in instances where repairs are not feasible without wholesale replacement of major generator components. With respect to generators, problems are usually related to the premature aging of individual components and their effect on generator availability.

Plant system engineering records often contain a collection of these communications, which should be reviewed and compared to maintenance records. Future generator performance may depend on the implementation of the recommendations made via these communications.

4.2.3 European Data

The European Industry Reliability Data Bank, EIReDA 1998, Crete University Press reports generator failure rate based on the French EDF data and represents PWR plants. The main generator failure rate is $2.0E^{-5}$ per service hour. At 7000 average service hours per year this yields 0.14 failures/unit/year. This rate is somewhat higher, but still comparable to the NRPDS/EPIX generator failure rate of 0.092 calculated previously.

4.3 Experience in Fossil Units

Generator data from fossil units are presented here for general information purposes only. A direct comparison to generators at nuclear plants is not relevant, due to differences in design, operation and maintenance conditions of generators at fossil plants compared to nuclear plants. The generators at fossil plants are predominantly high-speed machines (3600 rpm), taking advantage of the higher available steam parameters and resulting in higher thermal efficiency. The design and construction is more challenging, resulting in higher sensitivity to dynamic responses (vibrations) in stators and rotors. They are often supplied in a more competitive market and have generally lower design margins. However, generators at fossil plants do have the same basic components as generators at nuclear plants. Users demand that generator availabilities be in similar ranges as those at nuclear plants.

For the purposes of this sourcebook only generators rated above 400 MW are used for data comparison. This is because these units are closer in age, availability requirements, and yearly service hours to nuclear units, and thus provide relevant similarities.

Table 4-5
NERC/GADS Adjusted Forced Outage Rates for Fossil Units, All Fuels

Units	Number of Units	Unit-Years	NERC/GADS Adjusted Forced Outage Rate
400-599 MW	257	1229	1.40 %
600-799 MW	127	604	1.30 %
800-999 MW	34	167	1.15 %
1000 MW +	14	64	3.46 %

The significant jump in FOR rates on the largest two-pole generators may indicate design extrapolation that was not supported by developments in material technologies. From failure statistics it is not clear whether this is the early breaking-in rate or the expected normal operating failure rate for this class of machines.

Comparison of Tables 4-3 and 4-5 indicates significantly greater fossil generator FOR rates at comparable nuclear generator ratings. The reasons are related to operating conditions, such as frequent starting and load cycling, higher specific loading of generator active components (stator winding, rotor), and less opportunity for regular preventive maintenance. Although much of the generator maintenance on fossil generators is completed concurrently with other major plant equipment (boilers, turbines), it is less frequent and of a shorter duration. The well-optimized generator PM and CM at nuclear plants during refueling outages enhances generator availability between outages and in most instances avoids extensions of planned outages.

5
GUIDANCE FOR PLANT-SPECIFIC SSC CONDITION & PERFORMANCE ASSESSMENT

This section addresses steps number 8, 10 and 11A in the LCM planning flow chart (Figure 2-2) as follows:

- Step 8: the plant-specific operating and performance history is compiled in Section 5.1.
- Step 10: a compilation and review of the plant-specific maintenance program for generators, leading to the establishment of a complete inventory of the current maintenance tasks and providing a basis for determining if enhancements or changes are desirable. Details on compiling a maintenance history are discussed in Section 5.2.
- Step 11A: characterize the current physical condition and performance of the generator(s) and the implementation of effective preventive maintenance procedures, diagnostics, and component condition monitoring. Details of the condition and performance assessments are discussed in Section 5.3.

In addition, this section provides guidance for plant-specific LCM planning for the generator. Also included (section 5.4) is a compilation and description of available and useful condition or performance monitoring programs.

5.1 Compiling SSC Operating and Performance History

The operating and performance history as well as the age of a generator and exciter has a major bearing on the LCM plan. A review of the past performance and a thorough assessment of the current condition of the existing equipment are of great importance in making realistic decisions for future operating plans and reliability expectations [15]. Past performance reviews are an important part of the condition assessment of specific generators components.

The following steps are recommended in assembling the operating and performance history for the generators and exciters:

1. Assemble the maintenance history of the generator and exciter components], and in particular, the corrective maintenance actions taken over the last 5 years. The maintenance history may indicate evidence of generic problems on individual generator components and the potential for their repetitive failures [12].

2. Review all unit outages assigned to generator and exciter failures, including outage durations and/or evaluated cost of loss of unit production. Trending of historic failure rates will identify generator components that may require special attention in future LCM plans.

3. Collect information on replacements and upgrades already completed or planned for the near future.

4. Gather design changes and performance enhancements that have been implemented over the last years.

5. Collect information on maintenance improvements made for early detection of, and/or correction of, developing failure mechanisms, particularly in stator and rotor insulation systems.

6. Compare records of past inspections and tests to recent results to identify possible areas of degradation in generator components.

7. Review present on-line monitoring systems and their results, to detect deviations from normal values, which may indicate the need for corrective action [22].

8. Review the Maintenance Rule performance parameters and trends, the system health reports, MR periodic assessments, and the number of MPPFs and repetitive MPFFs for any performance weaknesses or trends; include the past and present monitoring status (A-1 and A-2), goal setting and goal monitoring, and the effectiveness of the corrective actions implemented.

9. Review the available spare parts inventory for an indication of potential to improve generator availability by component replacement rather than repair.

5.2 Review of Current Maintenance Activities

5.2.1 Compiling Maintenance History

A review of current and past maintenance work provides data for economic evaluation and a record of generator PM and CM activities, including design changes, enhancements and replacements. All these tasks are covered by Work Orders (WO), which can be extracted from plant records. They normally contain descriptions of problems, how they were detected, root cause analyses, repetitive occurrence of similar problems, man-hours, and parts for corrective actions.

The Work Orders provide information about component failures, their duration to repair, costs, and consequences on other plant equipment or reactor scrams. The data can be used for assessment of generator reliability and for comparison to the generic performance data. The calculated failure rates are used in the economic evaluation of current maintenance costs and for comparison to alternative LCM maintenance plans.

The Work Order review can also be used to trend the annual corrective and preventive maintenance activities over the past several years. This will determine if the rate of occurrence of problems is increasing or decreasing, and if the ratio of corrective to preventive WOs and the associated costs are changing. An effective PM program should show a gradual decrease of corrective Work Orders and costs. The data can lead to the identification of additional corrective or preventive actions that may be justified in order to effect a positive change.

The most important Work Orders are those implementing corrective actions as a result of problems, replacements due to obsolescence, and design changes. They often contain information concerning the root cause of a problem, whether repetitive problems were involved, the cost and man-hours spent in the corrective action, and the reason why the problem was not detected in its initial 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 performance can only be improved by detecting and preventing problems and therefore it is important to identify the causes of these problems and to determine the actions that will prevent failure.

Many plants use external contractors to perform much of their outage maintenance work on generators and exciters. These contractors are often OEMs or their affiliated service organizations. The contract costs of these services may represent a significant proportion of all generator maintenance costs. Often such contracts include the turbine portion of the maintenance program; the cost of the generator portion must be extracted from the generator work program or may have to be estimated from the total contract price.

The distinction between which maintenance activities are PM and which are CM is often blurred. Each plant may have a somewhat different interpretation. For performing an LCM economic evaluation it is important to use a uniform definition. The EPRI LCM process uses the definitions from "Nuclear Power Plant Common Aging Terminology" [13]:

- Preventive Maintenance – actions that detect, preclude, or mitigate degradation of a functional system, structure, or component to sustain or extend its useful life by controlling degradation and failures to an acceptable level
- Corrective Maintenance – actions that restore, by repair, overhaul, or replacement, the capability of a failed system, structure, or component to function within acceptance criteria

PM is done on an *unfailed* component. CM is done on a *failed* component.

It should be recognized that in many cases these distinctions differ from plant practice. For example, in contrast to the above definitions, maintenance to refurbish a somewhat degraded but unfailed component is often categorized by plants as CM. Also, "planned maintenance" at a plant can, according to the definitions above, be either PM or CM, while "unplanned maintenance" at a plant is almost always CM.

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. The word "Maintenance" in LCM planning includes preventive, predictive and corrective actions on a system. These activities are included whether they were required by applicable Codes (IEEE, National Fire Protection Agency, State requirements, local requirements), by the insurance carrier, or by plant procedures, programs, policies, or reliability targets. Collecting the associated activity parameters will provide key input to developing a base case for LCM planning; for example, the annual frequency of a task. This base case is not only important for creating an inventory of current activities and total annual maintenance costs, but also for providing a benchmark for comparison to industry practice, and a basis from which the need for additional activities, enhancements, or task reduction opportunities in LCM alternatives can be judged. A convenient way to assemble this information is illustrated in the sample case laid out in Table 7-1.

5.3 Conducting the Condition and Performance Assessment

A condition assessment of a generator and exciter normally requires detailed visual inspection of internal components and a number of electrical tests. [21, 12, 9, 10, 31] This entails extensive dismantling of a machine, including removal of the generator rotor. A review of the most recent inspection and test report, including the record of any correction of defects, modifications, enhancements or parts replacements, will provide comprehensive information on the generator condition and performance. Table 5-1 provides a checklist of inspection areas for this purpose. Suggested elements of maintenance program surveys are listed in Table 5-2.

Other inspections, tests, diagnostics and monitoring may be conducted on the generator system. These reports provide data of daily trends and are intended for detection of developing problems. These include:

- Minor inspections of generator internals through manhole covers; these can be done occasionally during concurrent outages, or during refueling outages
- Vibration monitoring of bearings and hydrogen seals [22]
- Noise measurements around generators [22]
- Inspection for cooling water leaks at hydrogen coolers and exciter coolers [22]
- Temperature monitoring of internal components [22]
- Testing for partial discharges (PD) in stator winding [7, 21, 26]
- Monitoring for overheating of core insulation [16, 21, 22, 24]
- Monitoring for detection of shorted turns in rotors [8]

From the inspection and test data, the condition of generator components can be evaluated with respect to the observed degradation and aging. The need for future PM actions can be indicated.

All power reductions and unit trip events attributed to the generator and exciter since the plant in-service date should be tabulated. This review will provide plant-specific generator failure rates and forced outage rates, which can be compared to the generic industry data presented in Section 4.1. Significant discrepancies in the results will indicate whether PM enhancements are required. A range of options for the enhancements will be evaluated in LCM alternatives and the economic assessments will determine their ranking for possible implementation.

At the component level, the plant-specific failure rates should be evaluated and compared to industry data shown in Tables 4-1 and 4-2. Generic design or operating problems can be recognized or confirmed using the OEMs communications. Future plant-specific component failure rates can be estimated in LCM alternatives, depending on implemented PM and CM actions. Section 8 provides further guidance for estimating future failure rates.

A detailed review of current maintenance procedures and practices might identify deviations from the latest industry practices or OEM recommendations. Comparison of the plant inspection, test and maintenance tasks to industry practice and recommendations (Table 5-1) will illustrate where activity improvements or reductions can be made. If the inspection and test programs and frequency deviate significantly from the industry data, it presents an opportunity to enhance or delete activities, or adjust the duration between inspections. The condition of generator components should be the guide for such adjustments.

Some users have extended the periods between major generator inspections. Such extensions may be justified on the basis of past condition assessments, correction of any generic problems, and implementation of enhanced on-line monitoring for detection of developing failure mechanisms. It is expected that the generator reliability would not be compromised by adoption of such extensions

Identification of predictive maintenance tools and on-line monitoring of the condition of generator components may identify need for additional monitoring. Implementation of these PdM tools increases the effectiveness of PM and often justifies a decrease of PM frequency. It can also reduce the extent of damage to generator components from aging mechanisms, lower the cost of repairs, and extend the life of components. Insulation assessment software tools, on-line stator and rotor insulation monitoring, and end winding vibration monitoring mechanisms are some of the most effective PdM tools.

Also necessary is a critical review of the aging mechanisms summary (Table 6-1) to determine if relevant plant-specific aging management programs have been in use and are effective. Deficiencies may warrant program changes or enhancements.

Not all of the above information may be available. To the extent that it exists, it should be collected and analyzed.

Table 5-1
Condition Inspection List for Generator and Exciter

Generator Component	Inspection	Frequency	Tests	Condition at Plant
Stator Winding *End Winding*	General appearance: Cleanliness, oil deposits Condition of bracing, lashing Indication of insulation abrasion wear, dust, greasing Evidence of corona, discharges, surface tracking Insulation swelling, cracking Mechanical damage from loose pieces, vibration Evidence of water leaks	Minor inspection every 2 to 2 ½ years, or Every refuel outage	Visual inspection	
Slot Winding	Cleanliness in the bore, oil deposits Condition of slot wedges, wedge tightness mapping Evidence of bar vibration and insulation wear, insulation dust/greasing along wedges Wedge migration Wedge packing migration	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage	Visual inspection Insulation resistance (IR) Polarization Index (PI) Over-voltage (Hipot) Wedge tightness test *Optional, or as required:* Winding resistance D-C voltage step or ramp test; Power factor; Off-line partial discharge; Capacitance mapping; Pressure tests for winding water leaks	

Table 5-1
Condition Inspection List for Generator and Exciter (Continued)

Generator Component	Inspection	Frequency	Tests	Condition at Plant
Stator Core	Cleanliness, evidence of blockage in ventilation ducts Evidence of overheating of core finger surface, discoloration at hot spots Evidence of loose laminations, vibration, dust or greasing deposits on tooth surface or along wedges Evidence of broken laminations or foreign metallic objects Through-bolt tension check	Major inspection every 5 to 6 years, Every 3rd of 4th refueling outage	Visual inspection EL CID or core flux test Through-bolt insulation resistance *Optional, or as required:* Core pressure at fingers	
Rotor Winding	Condition of end winding, coil distortion or migration, insulation migration, coil blocks distortion/breakage, dirt in ventilating ducts Blockage of ventilation discharge ducts by wedges or from insulation migration Condition of lead studs and leads	Major inspection every 5 to 6 years, Every 3rd of 4th refueling outage	Visual inspection Insulation resistance Winding resistance Winding impedance Pressure test for leaks at lead studs and bore plugs	
Retaining Rings	Surface inspection for cracks Applies to 18-5 rings	Major inspection every 5 to 6 years, Every 3rd 4th refueling outage	Visual inspection *Optional, or as required:* Crack detection tests, fluorescent or red dye penetrant tests, Ultrasonic	

Table 5-1
Condition Inspection List for Generator and Exciter (Continued)

Generator Component	Inspection	Frequency	Tests	Condition at Plant
Rotor Body	Evidence of local surface overheating from negative sequence currents Evidence of tooth or wedge cracking Condition of wedges, loose wedges, wedge migration, signs of electrical pitting at wedge ends and from wedges to RR and rotor body	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage	Visual inspection Optional, or as required: Crack detection in suspected high stress regions	
Fans	Condition of fan attachments Inspection of blades for cracks	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage	Visual inspection Optional, or as required: Crack detection tests, dye tests, magnetic particle, ultrasonic	
Collector Rings	Surface condition, "patina" color, glazing, patterns from controlled rectifiers Grooving and uneven wear, Loss of ovality, brush bouncing Ring insulation condition, contamination	Weekly walkdowns Every outage Every 3rd or 4th refuel Every 3rd or 4th refuel	Visual Visual Visual, measurements Visual, resistance test	
Brushgear	Brush wear rate, Brush sparking, vibration, brush bouncing	Every brush change Weekly or daily	Visual Visual, Thermography	
Hydrogen Seals	Condition of seal ring surfaces and seal grooves Babbitt damage, electrical pitting Oil wipers/deflectors, rubs, oil leaks	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage	Visual inspection	
Hydrogen coolers	Water leaks in generator or hydrogen leaks in service water, crevice corrosion, fouling, tube sheet condition	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage	Visual, leak tests	

Table 5-1
Condition Inspection List for Generator and Exciter (Continued)

Generator Component	Inspection	Frequency	Tests	Condition at Plant
Exciters	Condition of stator and rotor winding insulation,	Major inspection every 5 to 6 years,	Visual inspection Insulation resistance (IR)	
Rotating exciters	Check of diode and fuse assemblies for current sharing, mechanical balance, bore lead insulation, PMG mechanical damage, General condition in exciter enclosure, contamination, oil/water leaks, air filters Inspection of brush gear and brush assembly, for signs of brush wear, glazing, brush chatter and breaking, Inspection of slip rings for signs of wear, grooving, surface glaze, carbon deposits, ovality Bearing & Journal Wear Bearing Insulation Megger TCs & RTDs check	Every 3rd or 4th refueling outage	Polarization Index (PI) Over voltage (Hipot)	
Stationary Rectifiers and Static Exciters	Condition of controlled rectifier cubicles: contamination, overheating, water leaks, blown thyristors, air filters, operation of air fans	**Every refuel outage**	**Visual** **Thermography**	
	Teflon Rectifier Cooling Tube Contamination Stationary rectifier water coolant leaks Troubleshooting for circuit integrity at all test points	Every 3rd or 4th refueling outage		

Table 5-1
Condition Inspection List for Generator and Exciter (Continued)

Generator Component	Inspection	Frequency	Tests	Condition at Plant
Automatic Voltage Regulator (AVR), **Voltage Regulator**	Troubleshooting for circuit integrity at all test points Loop testing/calibration	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage Minor inspection every 2 to 2 ½ years, or Every refuel outage	Visual inspection Specialized tests as per applicable manual	
Bearings	Condition of bearing surfaces, dirt and particles Indication of oil contamination Babbitt wipe, wear, electrical pitting, overheating Loss of babbitt bond	Major inspection every 5 to 6 years, Every 4th refueling outage	Visual inspection Insulation resistance test Ultrasonic	
Main Terminal Bushings and Extensions	Evidence of cracks, loss of seal, oil or water leak, loose bolts Hydrogen gas leak Condition of flexible connectors (internal and external), condition of standoff insulators at phase lead extensions, indication of vibration at lead box,	Major inspection every 5 to 6 years, Every 3rd or 4th refueling outage	Visual inspection Leak test	
Terminal CTs	Signs of vibrations Signs of relaxation at bolted connections	Minor inspection every 2 to 2 ½ years, or Every refuel outage		
PT cubicle	Signs of overheating Loss/reduction of electrical clearances	Every refuel outage		

5.4 Condition Monitoring Technologies

Generator condition and status monitoring systems broadly fall into one of two categories: on-line monitoring and off-line testing.

The on-line monitoring systems generally provide real-time status of some generator component states [22]. Their main roles are:

- To detect long-term trends for aging mechanisms: insulation temperature, winding vibration, PD testing and, rotor shorted-turn detection are all examples of possible trends. The normal expected values of monitored parameters are often laid out in national and international standards. A multistage alarm protection indicates the severity of a problem and provides the information necessary for PM and CM actions.
- Short-term events and transients such as frequent starting, load cycling and, reduction of coolant flow (flow restriction) produce rapid changes in operating temperatures or vibrations. High-level alarms, unit run-backs and trips/scrams may be expected. The generator is frequently still in good condition, requiring relatively short outage for CM work.
- Extreme and sudden fault conditions such as stator and rotor winding ground faults, phase to phase shorts, core faults and the like cannot be monitored. Generator and unit protections take the generating unit off-line in a forced outage. Extensive repairs and long outages are frequent under such conditions.

The main purpose of off-line testing is to diagnose, quantify, and locate a component's deterioration or its failure mode. These tests are often used for confirmation and assessment of an aging mechanisms already indicated by on-line monitoring. A battery of such tests is normally included in any major generator inspection plan.

A review of the available results from monitoring will aid the operating personnel in detecting developing failure mechanisms and to determine the effectiveness of immediate PM (or to plan for future PM). The review should indicate if current monitoring is effective in recognizing generator problems. It should also provide evidence for the possible necessity of implementing additional monitoring systems.

Some generator monitoring systems require installation of dedicated detection sensors within components at the time of manufacture, such as thermocouples (TC) or resistance temperature detectors (RTD) in stator windings and cores. These cannot be retrofitted, unless the winding or core is being replaced. Others may be implemented as monitoring enhancements, but may require significant dismantling of the generator components for installation.

5.4.1 On-Line Monitoring of Generators [22]

5.4.1.1 Temperature Monitoring

Monitoring of stator winding temperatures from RTDs and TCs in winding slots is effective in detecting sustained overload conditions and problems in cooling systems. In direct water- or direct hydrogen-cooled windings, this monitoring is less effective than direct measurement of coolant outlet temperatures from each bar.

The water outlet temperatures are the most direct indication of bar copper temperatures and peak temperatures of winding insulation. They respond quickly and accurately to changes in stator winding losses (I^2R losses) or changes in cooling water flow. They can identify sustained overload conditions and transient over-current heating excursions. Reduction or loss of water flow from the cooling water supply system is annunciated with minimum delay and a load runback initiated. Gradual or rapid plugging of hollow strands from debris in water system or from erosion/corrosion of strands can be identified.

5.4.1.1.1 Average Rotor Winding Temperature

Average rotor winding temperature can be monitored by reading average winding resistance. High accuracy of this reading is often difficult to achieve with normal station instrumentation. This monitoring does not sense the hot spots in the winding or rotor surface temperatures.

The average winding temperatures may be significantly below the hot spots at which the risk to insulation damage is the highest. It may thus provide false security at times when corrective action may be required. Some users prefer monitoring of excitation current for indication of winding heating, although this may not be valid in cases of gas flow blockage.

Monitoring of average winding temperatures is normally not available on windings connected to rotating diode rectifiers of rotating exciters.

5.4.1.1.2 Temperature of Rotor Winding Hot Spot

Temperature profiles in rotor windings vary significantly from design to design. These profiles are a compromise between winding fabrication, insulation thermal and mechanical properties, and ventilation arrangements. In the design and prototype testing of a new rotor's winding layout, a ratio between average winding temperature and the hot spot is usually established. A typical ratio of average to hot spot temperature may be in the order of 1.1 to 1.3, high ratios may be in the range of 1.6 to 2.0 . This ratio can be used to calculate and monitor the winding hot spot rather than the average rotor winding temperature. The calculation algorithms can be incorporated in local programmable processors or as subroutines at higher levels of unit control systems.

Such monitors are normally available on request from generator or exciter OEMs. Some users develop their own monitoring programs that include rotor hot spot calculations.

Although a corrective action is essential when temperature limits are exceeded, unit control remains with the operator, rather than automatic unit trip or runback protection.

5.4.1.2 Condition Monitors

Condition Monitors, sometimes called core monitors or generator condition monitors (GCM), detect the particulates produced by severe insulation overheating or burning. They have initially been developed for detecting overheating of the core insulation. Through introduction of tagging or sacrificial compounds, the overheating detection has been expanded to include the stator winding and rotor winding insulations. In addition, general location of the overheating zones can be identified, e.g. which end of stator, which end of rotor. The main risks to core integrity created by overheating are:

- Deterioration of core lamination insulation, resulting in circulating electrical currents through core material, causing severe overheating and melting of core steel.
- Relaxation of core pressure, resulting in fatigue cracking of core laminations, particularly in the core teeth region; the result of such decay is again loss of lamination insulation and overheating.

GCMs are effective detectors of severe overheating of stator core insulation. The indication of such overheating does not avoid the core damage itself, but it can identify dangerous operating ranges. Suitable changes in operating procedures and voltage control can significantly extend the useful core service life. It can also identify the need for timely remedial action or core replacement.

Severe overheating or burning of rotor winding insulation will be detected by the condition monitor, but will be difficult to confirm, unless suitable tagging compounds are used in rotor insulation. General location of overheating may be identified by use of different compounds in selected regions.

Application of tagging compounds on rotor surface may be used to detect severe heating in wedges and rotor teeth at each end from negative sequence currents. These will generally occur during stator voltage imbalance, system faults, and accidental unit breaker operation at rotor standstill or low speed.

5.4.1.3 Core Noise

Generator cores produce typical electric machinery noise, very similar to transformer noise. The absolute noise level is a characteristic of a specific design or construction and is not useful for assessment of core condition. However, the changes in the core noise energy level or frequency range are usually reflections of changes in the core structure.

Changes in core noise can be detected by experienced and trained personnel. This is a subjective and not well quantifiable detection, but it has served many users in detecting core problems. More accurate acoustic tests are now available for noise surveys. These can detect changes in noise energy outputs (vibration magnitudes) and frequency spectrum changes, indicating possible resonant conditions.

5.4.1.4 Phase Voltage

High or low phase voltage operation may be the result of excitation AVR problems. However, operation at a high generator terminal voltage may also be a deliberate action for enhanced system stability or high load delivery. In the absence of on-load tap changers, the output transformer voltage regulating taps with fixed settings are often set permanently high. Such operating conditions will result in long term, or permanent, higher-than-design flux densities in the generator core. A generator with design margins may survive such service without noticeable consequences. In marginal cores, this operation will result in elevated average temperature and hot spot core temperatures. In overheated regions the core insulation aging will accelerate and may result in premature core failures.

A record of operation at high terminal voltage can be a good indicator of core problems or of observed core damage.

5.4.1.5 Negative Sequence Current (I_2) Heating

Definition:

Over-heating of rotor surfaces, wedges and retaining rings from currents induced in rotors due to unbalanced load currents in stator windings; also called I_2^2t heating

The normal load current in three phase stator winding is balanced in all three phases. A generator is designed for this current so that the temperatures in all components remain within acceptable limits. Although the generator design normally includes some margins for accidents and bad operation, it is not possible to build machines that would survive all types and levels of service faults, such as bad synchronization, severe line faults of all types, or internal generator winding faults.

Such faults produce large unbalances in stator phase currents and by induction of large negative sequence currents in the rotor circuit. The frequency of these currents is twice power frequency and therefore the penetration of these currents in a non-laminated rotor body is relatively shallow; the current path is limited to rotor wedges and rotor body surfaces, one to two inches deep. Because of a comparatively high resistance of the I_2 path, severe heating of the wedges and rotor surfaces can occur. In addition, significant current pitting erosion is likely at wedge ends, between wedges and rotor teeth, and at rotor to retaining ring interfaces.

The main risks to rotors from such damage are:

- thermal embrittlement of rotor steel and possible crack initiations and propagation to failure
- wedge cracking and failures
- crack initiations in retaining rings and ring bursts

5.4.1.6 Output MVA, MW, MX (MVAR)

The generator power output parameters are available from station instrumentation and computer outputs. These outputs are accurate as they are used in the measurement of station output for revenue purposes.

The power output data are used to confirm that the generator power output is within the normal rated design range or within the generator capability as confirmed by tests performed in the plant. The generator operating points, as defined by the geometric sum of MW and MX (MVAR) vectors, should always be maintained within the capability chart as defined in the generator manual. Operation outside the capability chart can result in insulation overheating and damage to the stator winding, rotor winding and/or stator core.

The power output parameters are also often used to confirm information garnered from other monitoring outputs, such as winding temperature sensors, partial discharge tests, and end winding vibration.

5.4.1.7 Vibration Monitoring

On-line vibration monitoring of stator windings in service is normally not provided as part of the original equipment supplied by the OEM. Some users implement such monitoring as a retrofit on generators with confirmed winding vibration problems. In the past, the limitation was availability of the non-metallic sensors for installation on sensitive insulation surfaces and in high magnetic fields of windings. Such sensors are now commercially available, along with the suitable monitoring instrumentation.

All bearings are normally provided with vibration detectors; these may be pedestal vibration sensors, shaft riding or shaft proximity probes. They permit monitoring and recording of vibration amplitudes or accelerations. Alarm and trip levels are normally provided to protect the turbine and generator shafts and blades form excessive damage. High vibrations are symptoms of many possible problems: imbalance, misalignment, thermal sensitivity, damaged bearings, oil whip, rubs on shaft (oil wipers, hydrogen seal rings), bent overhangs, uneven stiffness, shorted rotor winding turns of coils, developing shaft cracks, and others.

Rotor winding coils with shorted turns operate at lower temperature than coils without shorted-turns. This thermal gradient can transfer to rotor body and cause a change in local thermal expansion of the steel. This causes rotor bowing, imbalance, and change in rotor vibration. Bearing vibration analysis can identify the thermal response sensitivity and indicate winding shorted turns.

5.4.1.8 Partial Discharge Testing/Monitoring

Monitoring of stator winding partial discharges will detect mechanisms causing insulation deterioration such as insulation abrasion in winding slots, delaminating of the main wall insulation, end winding tracking, damage to semi-con or stress grading paint and end winding contamination. Delaminated insulation develops voids within the main wall of the winding-to-core insulation. In these voids, partial discharges occur under the operating voltages, which are proportional to the number of the voids and their size.

Measuring systems are now available for on-line monitoring of partial discharges from the windings of large turbine generators. The systems consist of permanently installed sensors, either in the winding itself or in the output busses, and the testing instrumentation. The measurements can be automated for continuous on-line PD detection or made by tests carried out periodically, with the results trended over time.

The automated on-line PD monitor and the periodic PD testing systems are available from independent suppliers. These systems permit the user's maintenance personnel and their engineering staff to conduct the tests and interpret results. Some generator suppliers and consultants offer on-line PD test services and interpretation of results by specialists on a contract basis.

5.4.1.9 Cooling Water Leaks, Hydrogen Leak In Coolant

5.4.1.9.1 Hydrogen

Hydrogen gas leaks in the coolant circuit is an indication of a breach in the cooling system within the generator casing. There are literally thousands of brazed and compression fitting joints separating the water circuit from hydrogen gas with a high probability that some of the gas will leak into water system. In addition, there is some continuous permeation of gas through the walls of the Teflon tubes. Significant gas leaks imply that water leaks into the winding and causes damage to the winding insulation.

Hydrogen gas must be detrained from the water system. The amount of the detrained gas can be monitored and the risk of water leaks in the insulation can be assessed. In totally closed systems hydrogen can be extracted from water through special detraining tanks with calibrated volumes. The number of releases from such tanks can be counted and the gas leaks calculated.

In open vented systems, such as the GE design, a special monitor is available for on-line measurement of hydrogen leaks in the water system. Collection of hydrogen gas from the vent line is also feasible and some plants use this test. Only relatively large gas leaks can be detected by this method; small crevice corrosion leaks may not be detectable.

Hydrogen gas leak measuring systems have traditionally not been provided as part of the original equipment supply. Recent concern with water leaks in winding insulation has encouraged the development of such systems. They are now available for retrofits on generators with a high risk of water leaks.

5.4.1.9.2 Copper Oxides

The amount of dissolved oxygen in stator cooling water has been found to be critical in the assessment of the risk of winding copper corrosion and plugging of water conducting strands. A number of users report an increasing number of incidents of corrosion and erosion of the hollow strands due to water chemistry control problems. The dissolved oxygen content in the range of 100 - 500 ppb promotes the formation of the type of copper oxide that does not adhere well to the inner surface of the strands and is continually eroded by water. The continually forming debris, which flows through the strands, has been reported to accumulate at strand transportations and gradually block the flow of the cooling water. Failures of overheated bars have been reported.

5.4.1.10 Hydrogen Dew Point

Hydrogen gas supplied for use in generator cooling systems is normally clean and free of moisture. In a generator casing, some water vapors will mix with hydrogen and form a gas mixture. At the dew point temperature, water will precipitate from this gas and may deposit on insulation surfaces. This is generally not desirable, as some insulations are sensitive to moisture related damage and will decay.

The main source of moisture in generator casings in normal service is from the hydrogen seal oil. Although the oil may be treated in water centrifuges and a vacuum plant before entering the hydrogen seal, it contains some moisture. This moisture is released in the dry hydrogen gas as a portion of the seal oil enters the generator during normal seal function. If unchecked, the moisture content would gradually increase to the saturation point at operating temperature in the casing.

The water sources in a generator can also be attributed to water leaks from hydrogen coolers or from stator winding cooling water. In such cases this would be an indication that these systems were defective and required repairs.

The dew point of the generator gas should be maintained well below normal operating temperature in the casing, preferably below 0°C. This can be achieved by regular purging of portions of the hydrogen gas from the machine or by application of effective hydrogen dryers.

5.4.1.11 Shorted Turn/Coil Detector in Rotor Winding (Air-Gap Flux Monitor)

Most rotor shorted turns occur in a rotor winding from high compressive loads on insulation at rated speed and from thermal differential expansions between the insulation and copper turns. Contamination of the rotor ventilation circuits with metallic particles is also a frequent cause of shorted turns and ground faults. A single shorted turn may be tolerated in-service for many years with little effect on generator performance. However, a larger percentage of shorted turns can cause the generator load reduction and in severe cases, forced outages, mostly from excessive shaft vibrations. Recently such vibrations developed on rotors at two nuclear plants.

Rotor winding coils with shorted turns operate at lower temperatures than coils without shorted turns. This thermal gradient can transfer to the rotor body and cause a change in local thermal expansion of the steel. This causes rotor bowing, imbalance, and change in rotor vibration. Bearing vibration analysis can identify the thermal response sensitivity and indicate winding shorted turns.

Shorted turns in four pole rotors cause imbalance in the main magnetic flux in the air gap and an imbalance in magnetic forces. The effect of this force imbalance results in shaft vibrations at a frequency of one per revolution.

The consequence of shorted turns on unit operation will depend on number of shorted turns and their distribution in the winding. The generator is forced out of service when the shaft vibrations exceed the vibration limits. Generators can normally operate at rated output with one or two shorted turns. Early detection of shorted turns provides information for planning corrective action before a unit is forced out of service.

5.4.1.12 Rotor Winding Ground Detector

The DC rotor winding is not normally grounded in service, except through a ground detection relay. Therefore, the first short of the field winding with rotor forging, or single ground, by itself does not produce further damage to the winding or shaft. The second ground, however, will produce a short circuit path between the two grounds. The resulting circulating fault current can result in the burning of the winding insulation and melting of winding copper as well as forging steel. The rotor normally cannot be repaired after such an event; the risk of shaft burst and of complete generator destruction cannot be ignored.

The operation of a generator after the indication of the first ground is a subject of risk assessment. Some OEMs recommend a unit trip and immediate correction of the winding ground fault. Others permit the operator to maintain unit control and follow the standing operating procedures. Often the unit remains in service for days or weeks, until a convenient maintenance outage can be arranged for the repair, thereby accepting the risk of a second ground and its consequences. Increasingly, users are adopting a practice whereby the generator is taken out of service within an hour or two, after the ground has been confirmed and the unit can be unloaded without affecting system stability. Rotor winding ground monitoring and protection relays are available from OEMs, either as part of the original equipment supply, or on a retrofit basis.

6 GENERIC AGING AND OBSOLESCENCE ASSESSMENT

6.1 Aging Mechanisms Review

This section addresses step 11b, Perform Aging Assessment, in the LCM planning flow chart in Figure 2-2.

Normal aging of generator components occurs when a generator operates within rated power, at rated voltage and frequency, within rated temperatures, and within normal system operating conditions over time. The limits of these parameters are defined in national standards; manufacturers may apply additional internal design standards in order to meet the user Performance Specifications for plant life expectancy [14].

Generator life expectancy implies that some preventive or condition-based maintenance will take place at defined intervals or as indicated by condition monitoring systems. In addition, the generator will be protected against system operating events that would result in non-repairable accelerated deterioration.

For this purpose the following conditions should be considered:

- Generator operating within the design rating parameters
- Monitoring and trending of generator condition
- Detection of accelerated deterioration
- Preventive and corrective actions taken to ensure generator integrity
- History of operating conditions

A comprehensive outline of winding insulation failure and aging mechanisms in generator stators and rotors can be found in EPRI Volume 16, Handbook to Assess Rotating Machine Insulation Condition [21], and in the Technical Help sections of MICAA [12] and GenLife [11] software programs developed for assessment of insulation condition and risk of failure in generator stator windings.

Table 6-1 provides a summary of the main aging mechanisms, their effect on generator components, and the current detection systems and remedial actions available to aid management of generator aging.

Table 6-1
List of Generator Component Aging Mechanisms

Component	Material/Sub-Component	Aging Mechanisms	Aging Effect	Aging Management
Stator winding	Insulation	Overheating	Embrittlement, delamination Ground faults Phase-phase faults	Temperature monitor PD monitor Condition monitor with tagging compounds Robotic or visual inspections Replace bars, replace winding
		Abrasion in slots	Insulation thinning Insulation breakdown Ground faults Phase-phase faults	5 year inspections PD monitor Re-wedge Replace bars, replace winding
		End winding vibration	Insulation wear, phase-phase faults	Stiffen winding supports Vibration monitor
		Contamination	Surface discharges Insulation wear Phase-phase faults	PD monitor Winding cleaning
		Cooling water leaks	Insulation decay Ground faults	Leak monitoring and tests Capacitance mapping Leak repair, clip replacement, epoxy injection Bar replacement, winding replacement
	Copper conductors	Strand erosion	Strand plugging Reduction/loss of cooling, overheating Insulation failure	Temperature monitoring Oxygen-in-coolant control Chemical cleaning Bar replacement, winding replacement

Table 6-1
List of Generator Component Aging Mechanisms (Continued)

Component	Material/Sub-Component	Aging Mechanisms	Aging Effect	Aging Management
Stator winding (continued)		Vibration	Fatigue cracking of conductor strands Cracking of winding series connections Electrical arcing, insulation breakdown Ground and phase-phase faults	Vibration monitoring Re-wedging and stiffening of end winding supports Bar replacement, winding replacement
	Voltage grading	Abrasion	Slot discharge, insulation failure	PD testing Rewedge Bar replacement, winding replacement
	Slot wedging system	Los of pressure Loss of winding support in slots	Bar vibration Insulation breakdown Ground faults Phase-phase faults	PD testing Robotic or visual inspections Rewedge Bar replacement, winding replacement
	End winding support	Relaxation Vibration	Bar vibration, insulation wear Phase-phase faults	Vibration monitor Visual inspections Stiffen support Bar replacement, winding replacement
	Winding extensions	Support relaxation Vibration Cracking of standoff insulators	Insulation wear Ground faults Phase-phase fault	Visual inspections
	Terminal bushings	Overheating Loss of seal	Cracking of insulation/porcelain Hydrogen leaks	Replace bushings Replace seals

Table 6-1
List of Generator Component Aging Mechanisms (Continued)

Component	Material/Sub-Component	Aging Mechanisms	Aging Effect	Aging Management
Stator core	Insulation	Overheating	Inter-laminar current heating Core burning and melting	5 year inspection, visual or robotic EL CID or ring flux test Temperature monitoring Core monitor
	Laminations, Ventilation spacers	Loss of core pressure Core bolt stretching Lamination vibration	Punching and spacer breaking Lamination shorting Core melting	Core monitor Visual or robotic inspection Core pressure tests Core repairs Use of penetrating epoxy
	Building bolts Core bolts	Strain elongation	Loss of core pressure	Inspections Bolt tightening
Rotor	Winding insulation	Overheating Breaking Migration Abrasion Contamination	Turn shorts Ground faults	Shorted turn monitoring Ground monitoring and protection Inspections for ventilation blocking Shaft vibration monitoring Shorted turn/ground repairs Rotor rewind
Rotor (continued)	Winding copper	Distortion Creep elongation Coil connection cracking Lead-in cracking Loss of seal at radial bolt Copper dusting	Turn or coil shorts Ground faults Gas leak along shaft lead Risk of second ground and forging damage	Shorted turn monitoring Ground monitoring and protection Gas leak monitoring Shaft vibration monitoring Inspection for copper dust Shorted turn/ground repairs Rotor rewind

Table 6-1
List of Generator Component Aging Mechanisms (Continued)

Component	Material/Sub-Component	Aging Mechanisms	Aging Effect	Aging Management
	Wedges	Cracking Migration Spark erosion	Breaking Blocking of ventilation High negative sequence current	Inspection, Replacement
	Forging	Top tooth cracking Crack initiations at stress risers, Journal damage at bearings and hydrogen seals	Low and high cycle crack propagation Shaft vibration	Vibration monitoring and modal analysis
	Fans, Blowers Balance weights	Blade cracking Weights separation	Missile damage to stator winding	Inspections, weights staking
	Retaining rings	Corrosion cracking	Disintegration	Inspections, replacement
	Hydrogen seals	Gas leaks Oil leaks in generator Seal ring damage	Hydrogen fire Winding contamination	Inspection, gas leak/makeup monitoring, seal installation procedures
Rotating Exciter	Alternator	Stator and rotor winding insulation overheating Mechanical integrity Contamination	Insulation breakdown Copper fatigue cracking	Inspections, repairs, replacement
	Rotating rectifier diodes, Fuses	Diode and fuse failures	Loss of excitation	Monitoring, replacement

Table 6-1
List of Generator Component Aging Mechanisms (Continued)

Component	Material/Sub-Component	Aging Mechanisms	Aging Effect	Aging Management
	PMG	Misalignment Vibration	Loss of excitation control power	Inspect, monitor
	Voltage regulator, Automatic voltage regulator (AVR)	Bad wiring connections Circuit card failures	Excitation transients Loss of excitation	Replacement of failed cards
Static Exciter	Controlled static rectifier	Thyristor failures	Loss of excitation of fault indication	Replace failed parts
	Automatic voltage regulator (AVR)	Bad wiring connections Circuit card failure	Loss of excitation of fault indication	Replace failed parts
	Gate pulse generator	Bad wiring connections Circuit card failure	Loss of excitation of fault indication	Replace failed parts
Current transformers	Generator terminal mounted	Overheating Vibration	Loss of protections Loss of current reference to exciter	Inspections, changes to ventilation and supports
Potential transformers	Separate PT cubicles	Overheating Vibrations Connection breaking	Loss of voltage metering Loss of reference to exciter	Inspections, changes to ventilation and supports
Hydrogen coolers	Finned copper, brass or copper-nickel alloy tubes, assembled in heat exchangers	Tube cracking Fouling on service water side Water leaks in generator Loss of service water	Hydrogen leak to SW Water leaks on winding Loss/reduction of cooling, overheating of core and rotor winding	Monitoring of gas temperatures Liquid-in-generator detection Plugging of leaking tubes Tube/cooler replacement

6.2 Expected Lifetimes of Major Components

There is an expectation that a generator will be designed and manufactured so that it will operate at average generator reliability for a period of 30 years, under normal operating conditions, without the need for any major component replacements or upgrades. All generator components are traditionally designed for a 30-year life expectancy. This time period related more to the period of plant amortization rather than to accurate technical design life. Most power generating plants, including nuclear plants, have extended the expected operating life to 40 years. This was obtained by extending the licensing permits and in consultation with their respective equipment OEMs.

Actual in-service experience of large generators indicates that the actual life of generator components may be significantly different from the expected design life of 30 years. All active generator components are subjected to wear and degradation. The rate of this degradation is affected by initial design and fabrication, operating conditions, and preventive and corrective maintenance practices. Recognition of the early stages of deterioration and timely repair intervention also play an important role in generator component life. Some typical ranges of life expectancies of generator components are shown in Table 6-2, along with failure mechanisms and failure causes.

Table 6-2
Ranges of Life Expectancies of Generator Components

Component	Failure Mechanisms	Causes of Failure	Life Expectancy
Stator Winding	Thermal degradation; mechanical wear and fatigue; voltage stress; chemical change; contamination	Ground failure; phase-to-phase short; cracking	20-60 years
Stator Core	Thermal degradation of insulation; loss of core pressure; fatigue of core parts	Core burning and melting; breaking of core teeth and core spacers	30-60 years
Rotor Winding	Thermal aging; insulation wear, cracking, migration; conductor deformation; conductive contamination	Shorted turns; ground faults; cracking	20-25 years
Rotor Forging	Low cycle fatigue crack initiation; high cycle fatigue crack propagation; negative sequence current overheating; torsional fatigue	Wedge cracking; tooth cracking; shaft cracking	30-60 years
Retaining Rings	Aqueous corrosion and stress corrosion cracking; fatigue crack initiations at stress risers	Crack propagation; ring burst	20-60 years
Exciters; AVRs	Aging of rotor and stator insulation; aging of electronic components	Loss of control or power circuits; loss of excitation; over-excitation	10-30 years

The above listed life expectancy periods can be used for long range planning of component replacement or major upgrade work. They reflect the actual field experience in the industry, but may not be applicable to all generators to the same extent. For instance, the life of a sound rotor forging is expected to be 60 years or more; however, a life of only five years was experienced on a few forgings that had design flaws, which were not recognized during the design and manufacturing stage.

The plant-specific life expectancy of any generator component should be evaluated from the condition assessment results and evaluation of generic problems known to exist for each component.

6.3 Technical Obsolescence

Some components in a generator system are sensitive to technical obsolescence. The electronic control, monitoring and protection components and circuit cards in exciters are examples of components sensitive to technical obsolescence. These components are used in most nuclear units and were designed and assembled in the early and mid-seventies. In LCM planning the replacement of components should be considered when the availability of spare parts becomes limited and the failure rates on the system are rising to unacceptable levels. The availability of parts from alternative sources and some reverse engineering of obsolete components can be considered, if they are cost effective.

The first step in the assessment of technical obsolescence of a system should follow the method provided in Table 2-2 of the Life Cycle Management Sourcebook Overview report [3]. This was done for all generator components discussed in this sourcebook and it became clear that the exciter control circuits, including voltage regulators, are subject to technical obsolescence and contingency planning and options should be considered.

The obsolescence criteria are as follows:

- 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 advancements in microprocessors and digital control systems of new excitation systems offer improved functionality, better reliability and better maintainability. The self-checking, automatic fault detection circuits and redundancy capabilities may support the replacement of existing exciters even in instances where the current operational maintenance is still manageable. The reliability of new equipment should to be addressed at the design level to obtain reasonable assurance for optimal operational performance. The potential maintenance costs of new designs, run-in reliability and lack of operating experience must be carefully evaluated. Table 6-3 provides an example of an obsolescence assessment for an outdated exciter.

No other generator components were identified as technically obsolete. Although, some material technology progress has been made in the past 10 years, the basic generator design remains unchanged, including the cooling methods and material utilization limits.

The “score” column represents the “value” of the obsolescence evaluation criteria for individual items. The “yes” column is used in the plant-specific evaluation. The Total Obsolescence Score is used for the assessment of the degree of the obsolescence, as shown above.

As can be seen from the example in Table 6-3, the exciters as originally supplied are no longer produced, but the availability of spare parts and feasibility of integrating new exciters in the generator system results in a total score of 6.0. This is considered a borderline yellow, just short of the red condition – the most serious obsolescence situation. This is an example of a component requiring near-term contingency action. While this process only provides a quick and quantitative method to assign the component an obsolescence priority, the yellow and red conditions should be targeted for a more in-depth obsolescence study that can help to determine what actions should be taken.

Within the next 5-10 years exciter obsolescence will be an industry-wide problem at nuclear power plants. In view of this, the LCM planning alternatives discussed in the following section will focus on the obsolescence issue and provide guidance in contingency planning.

Table 6-3
Example Obsolescence Assessment

	Technical Obsolescence Evaluation Criteria	Score	Yes
1	Is the exciter still being manufactured and will it be available for at least the next five years?	5	
2	Is there more than one supplier for the exciter for the foreseeable future?	3	
3	Can the plant or outside suppliers manufacture the exciter in a reasonable time (within a refueling outage)?	3	
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	3
5	Is the exciter frequency of failure/year times the remaining operating life (in years) equal or lower than the number of stocked SSCs in the warehouse?	3	
6	Can the spare part inventory be maintained for at least the next five years?	3	
7	Is the exciter immune to significant aging degradation?	1	
8	Can newer designs, technology, concepts be readily integrated with the existing configuration (hardware-software, digital-analog, solid-state, miniaturized electronics, smart components, etc)?	3	3
9	Is technical upgrading desirable, commensurate with safety and cost effective?	3	
	Total Obsolescence Score		6

7 GENERIC ALTERNATIVE LCM PLANS

This section addresses step numbers 12 through 17 in the LCM planning flowchart (Figure 2-2).

The EPRI LCM report [1] defines 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 guide 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 an example of a hypothetical alternative LCM plan including discussions on the logic and assumptions made during the process of building an alternative LCM plan.

7.1 Plant Operating Strategies and Types of LCM Planning Alternatives

The LCM planning alternatives at each plant will be determined largely on the basis of current reliability performance of its generators and exciters. Therefore, the LCM planning alternatives proposed for evaluation at each plant will be very much plant-specific.

Some typical plant operating strategies and approaches to LCM planning are outlined below:

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

This strategy requires minimizing risk during the remaining operating period until the plant's original 40-year license expires by identifying limiting SSCs, which could result in premature power reduction and force an economic decision regarding early decommissioning.

LCM plan alternatives under this strategy may be:

- **LCM Plan Alternative 1A**: A base case to determine the cost of the activities performed under the current maintenance plan, assuming that the current activities will continue to the end of the licensed plant life. This case assumes the ***continuation of the existing maintenance programs without any major capital investments*** unless they are necessary for continuation of plant operation.
- **LCM Plan Alternative 1B**: A plan where the current maintenance plan is optimized and an ***aggressive PM program*** is implemented to reduce equipment failures, lost power production and regulatory risk. The plan includes the purchase of additional generator component condition monitors to detect aging mechanisms in the early stages, enabling timely repairs

and limiting the risk of sudden failures. Replacement of major parts may also be required in order to secure a 40 year operating life at target performance levels, e.g. planned replacement of obsolete exciters, planned rewind of rotors.

- **LCM Plan Alternative 1C**: An alternative in which the current maintenance plan is optimized and degraded generator components are replaced with new and upgraded parts, e.g. stator winding replacement, rotor rewind and the purchase of a new rotor. The target of such a plan is to reduce the current level of the generator failure rate and lower unit production losses.

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

This strategy recognizes the potential for license renewal and extended plant life. Extended operation may require investment in major generator components, including possible generator replacement. This investment may only be justified by additional revenue generated in the additional 20 year operating term. LCM planning alternatives under these conditions may include:

- **LCM Plan Alternative 2A**: A base case to determine the cost of the activities performed under the current maintenance plan, assuming that the current activities will continue to the end of the licensed plant life. This case assumes the continuation of the existing maintenance programs without any major capital investments unless they are necessary for continuation of plant operation. Such plan may not be viable in the context of license renewal, but may be useful for economic comparison to other alternatives.
- **LCM Plan Alternative 2B**: A rigorous preparation for license renewal with aggressive aging management program and timely component replacements or upgrades. The plan includes adoption of condition-based maintenance, planned replacement of exciters, possible stator rewinds, and planned rotor rewinds.
- **LCM Plan Alternative 2C**: Preparing for license renewal with aggressive PM and PdM programs, but delaying plans for major capital investments until a decision for license extension is made and implemented. Extended license is implemented.

7.2 Development of Alternative LCM Plans

For each LCM Plan, alternative detailed maintenance activities and scheduled activities should be identified. These plans may include the need to:

- Adjust the frequency of maintenance activities on generator to enhance reliability or to reduce maintenance costs.
- Implement diagnostics for transition from time-based PM to condition based maintenance (PD monitoring, rotor shorted turn detector, rotor temperature).
- Add PM and CM maintenance activities to enhance the generator availability (core inspections and testing).
- Operate generator within capability limits; operation at balanced conditions away from extreme voltage, current and excitation conditions, even if they are still within capability limits.

- Upgrade or replace major generator components, rewind stator and rotor, and purchase spare rotor. The upgrading may be required due to premature component aging, which causes an increase in the generator failure rate. Purchase of major spares may be justified on the basis of limiting the unit outage to component replacement time instead of component repair or purchase order time.
- Examine the technical obsolescence of exciters.

In each LCM planning alternative, all costs and benefits should be considered.

7.3 Hypothetical Illustration of Formulating LCM Planning Alternatives

This section describes a hypothetical case to illustrate the process of formulating the information and data for economic evaluations of generator system LCM plan alternatives.

Consider a nuclear plant with 2 units. The generators at each unit have the same nominal rating of 1000 MW and are from the same manufacturer, employing the same design. The operating term of the units is expected to be 40 years.

The plant is 20 years old. Generator in-service dates are: Unit 1 Jan 1983, Unit 2 Jan 1984.

The average price of replacement power for these units is assumed to be 50 $/MWH and labor cost is $50 per hour.

7.3.1 Historical and Future Failure Rates

A review of plant outages identified eight records of forced outages attributed to the two generators and exciters (Table 7-1).

Table 7-1
Hypothetical Records of Generator Failures That Caused Forced Outage Time

No	Unit	Event Date	Generator/Exciter Component	Outage Duration Days/Hours	Outage Cost
1	1	1/1/87	Stator winding water leak	FEPO, 5 days, 120 Hrs	$ 6.0 M
2	2	5/5/90	Rotor winding shorted turn	FO, 20 days 480 Hrs	$ 24.0 M
3	1	1/3/92	Loss of Excitation, AVR fail	FO, 2 days 48 Hrs	$ 2.4 M
4	2	3/5/95	Loss of Excitation, blown fuses and Thyristors	FO, 3 days 72 Hrs	$ 3.6 M
5	1	6/1/98	Rotor ground fault	FO, 30 days 720 Hrs	$ 36.0 M
6	2	3/5/00	Stator winding water leak, replace top and bottom bars	FO, 35 days, 840 Hrs	$ 42.0 M
7	1	6/9/01	Loss of excitation, gate pulse generator card fail	FO, 3 days 72 Hrs	$ 3.6 M
8	1	2/2/02	Hydrogen cooler tube leak	FO, 2 days 48 Hrs	$ 2.4 M

In 2003 the combined generator and exciter time in service is 20 + 19 = 39 years. The failure rate is calculated at:

F = 8 failures in 39 operating years = 8/39 = 0.205 failures/unit year

The generator failures contributed on average of 120 forced outage hours per year, or a loss of 120,000 MWH per year at an average yearly cost of $6.0 million.

The forced outage rate (FOR), calculated on the basis of average yearly unit operating service factor of 0.8, or 7008 hours is:

FOR = forced outage hours divided by the sum of operating hours and forced outage hours

FOR = 120/7128 x 100% = 1.68 %

Table 7-2 compares the plant-specific generator performance data above to the industry data from Table 4-2. In this illustration, the components are selected and grouped on the basis of the plant-specific recorded failures in Table 7-1. This list may be different for each plant.

Table 7-2
Historical Generator Component Failure Rates Per Unit

Component	Industry Average Failure Rate	Plant-specific Failure Rate
Generator and Exciter	0.092	0.205
Stator Winding	0.016	0.051
Rotor Winding	0.0056	0.051
Exciter (including voltage regulator)	0.035	0.077
Other (hydrogen cooler)	0.0024	0.026

7.3.2 Current Maintenance Practices

The review of current maintenance practices notes that monitoring of the generator condition in-service is limited to power output parameters (output voltage, phase current, MW and MVA), stator winding temperatures, GCM, bearing temperatures, and bearing vibrations. Additional instrumentation has been provided as part of the original supply for monitoring such parameters as pressures, differential pressures, coolant temperatures, flows, and gross consumption (makeup rate) for cooling water and hydrogen gas.

Additional on-line monitors, such as stator end winding vibration, rotor shorted turn detector, and partial discharge testing of stator winding, have been considered in the past, but have not yet been implemented.

Periodic generator inspections, tests, and preventive and corrective maintenance work are currently completed during reactor refueling outages consistent with practice in the nuclear industry. However, major generator inspections with rotor removal are scheduled every 5th refuel outage, or every 7.5 to 8 years. This is greater than the OEM-recommended 5- to 6-year interval generally adopted by the industry. Some minor PM is done with the generator at power, such as operator walk downs; instrument and protection circuit calibration; brush replacements; monitoring; and adjustment to coolant pressures and flows. Maintenance activity details are shown in Tables 7-3 and 7-4, indicating the individual activity costs in terms of man-hours and material expenses, as well as yearly averages for PM and CM activities at power and during refueling outages.

Table 7-3
Current Maintenance Activity List, At-Power

Activity	PM CM	Interval Days	Labor Hrs/ Interval	Labor Hrs/ Year	Labor @ $50/H	Material $/Year
Hydrogen leaks from casing	PM	7	2	104	5,200	300
Inspect/Clean brushes Brush Maintain/Replace Collectors inspection	PM	7	3	150	7,500	3000
Generator Monthly Inspection	PM	30	2	24	1,200	
Exciter inspection, Shaft voltage measurement, Thermography monitoring	PM	30	3	36	1,800	500
Inspect Exciter House Filter	PM	90	4	16	800	500
Measure vibration of brush rigging	PM	90	4	16	800	
Measure vibration/analysis	PM	90	6	24	1,200	
Thermography on brush rigging and rectifier	PM	90	6	24	1,200	200
Hydrogen leaks in stator Cooling water	PM	180	4	8	400	
Remove/replace filters	PM	365	4	4	200	1,000
Post maintenance monitoring	PM	550	57	40	2,000	
Engineering/Planning	PM			50	2,500	
Total Cost/Year					24,800	5,500

Table 7-4
Current Maintenance Activity List, During Outages

Activity	PM CM	Interval Days	Labor Hrs/ Interval	Labor Hrs/ Year	Labor @ $50/H	Material $/Outage $/Year
Exciter Minor Inspection	PM	550	60	40	2,000	2,000 1,300
Generator Minor Inspection	PM	550	120	80	4,000	25,000 16,600
Test Rotor Ground Detector	PM	550	6	4	200	1,000 660
Liquid in Terminal Box	PM	550	6	4	200	
TVR Clean/Inspect	PM	550	16	12	600	1,000 660
HV Bushing Refurbishment	PM	2745	1000		6,700	15,000 2,000
Generator/Exciter Major Inspection with Fast-Gen	PM	5490	13000		43,400	50,000 3,300
Generator/Exciter Major Inspection with Rotor Pull	PM	5490	17000		56,600	100,000 6,600
Repair Leak	CM			10	500	5000
Bearing Vibration	CM			12	600	10,000
Generator Air Test	PM			40	2,000	2,000
Shaft Balance	CM			40	2,000	
Engineering/Planning	PM			50	2,500	
Total Cost/Year					121,300	48,120

7.3.3 LCM Planning Alternatives

The **base case 1A** assumes that the present maintenance program will continue without major upgrades or component replacements. The latest condition assessment concluded that the generator and exciter are capable of operating for 40 years under the current licensed term. Future failure rates are estimated based on engineering judgment of the merits of completed repairs after failures. It is expected that the future failure rates will improve as a result of the completed repairs, although they may remain above industry average. Table 7-5 shows both the historical plant-specific failure rates and the estimated future rates.

Table 7-5
Lost Power Generation and Repair Costs, Alternative 1A

Component	Plant-specific Failure Rate Per Year		Average Outage Duration H	Lost Power Generation $K	Repair Cost/Failure $K/Failure	Repair Cost $K/year
	Historic	Future				
Stator Winding	0.051	0.04	720	1,440	800	32.0
Rotor Winding	0.051	0.04	480	960	500	20.0
Exciter and AVR	0.077	0.07	48	168	20	1.4
Other (Hydrogen cooler)	0.026	0.026	24	31.2	10	0.3
Total				2,599		53.7

Table 7-5 indicates that the total yearly generator cost is dominated by the probable lost power generation cost derived from the estimated future failure rates. The same holds for the other alternatives discussed in the following paragraphs.

The **LCM alternative 1B** proposes to adopt elements of condition based maintenance by enhancing on-line monitoring for detection of early signs of aging in a major generator component, namely winding insulation in stators and rotors. The new monitors include: on-line detection of coolant leaks in stator winding, end winding vibration monitoring, partial discharge monitoring in stator winding, and detection for shorted turns in rotor winding. It is estimated that the failure rate of stator and rotor winding will drop by a factor of two, because the gradually developing problems will be detected and recognized before a failure. Due to early detection, there will be an opportunity to correct the problems during planned outages within refueling periods. Therefore there is a significant improvement in estimated future failure rates, as shown in Table 7-6. A capital expense for replacement of obsolete analog controls in the excitation system is also included to ensure reliable service until the end of the 40-year operating term. The major generator and exciter inspection periods will be adjusted to every 4th refueling outage (6 years) from the current every 5th refueling outage (7.5 years).

Table 7-6
Lost Power Generation and Repair Costs, Case 1B

Component	Plant-specific Failure Rate	Average Outage Duration H	Lost Power Generation Cost $K	Repair Cost/Failure $K	Repair Cost $K/Year
Stator Winding	0.02	720	720	800	16.0
Rotor Winding	0.02	480	480	500	10.0
Exciter and AVR	0.035	48	84	20	0.7
Other (Hydrogen cooler)	0.026	24	31	10	0.3
Total			1,315		27.0

The projected future failure rates are estimated from the benefit of on-line monitoring and early detection of developing problems in stator and rotor windings. It is estimated that there will be an opportunity to correct any identified degradation within the planned refueling outages, thus avoiding forced outages. The upgraded exciter will also perform at a reduced failure rate.

In alternative 1B, there are capital investment costs of implementing new monitors for stator and rotor winding and upgrading of the exciter to a digital design:

New monitors: $200K
Exciter upgrading: $1000K

The average yearly PM cost of major generator and exciter inspections every 7.5 years is $100,000. The frequency of the inspections will be increased to every 6 years. This will increase the yearly cost of the major inspections.

Increased yearly PM costs: 7.5/6 x $100,000 - $100,000 = $125,000 - $100,000 = $25,000.

The difference in the yearly loss of power generation between base case Alternative 1A and Alternative 1B is about $1.31M. Although the PM cost increases by $25,000 per year due to increased frequency of major inspections, the total yearly savings are about $1.285M. Because the lost power generation costs are based on the projected assessment of future failure rates at the plant level, they need to be well documented and supported by data from industry experience.

In **LCM alternative 1C** a more aggressive plan was considered, including stator winding replacements (rewinds) and the purchase of a new rotor, which would serve as a spare for both generators. The stator winding condition indicates generic problems of water leaks and insulation damage, the rotor winding insulation is aging and shorted turns are expected to occur at an increasing frequency. The replacement of the stator winding is a major effort requiring a 30 to 50 day unit outage, when scheduled well in advance and with all materials pre-ordered and delivered to the rewind site. The contract cost of a rewind can range from $10 to $15 million dollars, depending on generator size, winding layout, delivery priority and market conditions. For these reasons, the decision to implement a stator rewind is often made for a combination of reasons, rather than for a single type of aging degradation. In stator winding replacements there is frequently an opportunity to optimize the winding design by reducing the winding losses (increasing efficiency) and uprating the generator capability. These gains partially offset the cost of a rewind by increased unit power output, capitalized over the life of the plant.

The rotor winding insulation damage may be caused by these major stressors:

1. High compressive stresses due to centrifugal forces

2. Tensile stresses from thermal expansions during load transient

3. Start-stop cycling

4. Contamination of insulation between winding turns. (Conductive contaminants such as iron swarf or copper dust frequently bridge the insulation between copper turns at ventilation holes or in the end winding region.)

Rotor winding shorted turns and ground faults are the mechanisms for winding insulation degradation and aging. Although the repair of shorted turns and ground faults is possible in most situations, it requires rotor removal from the generator, removal of the retaining rings, testing for the fault location and partial or full removal of a winding coil, before the repair can be completed. Such repair would typically cost about $0.5 million and require a 20-day unit outage with advanced preparation, or up to 50 days under sudden forced outage conditions. When general insulation degradation is identified, then the risks of further shorted turns or ground faults drive the decision for a complete re-insulation of the rotor winding (rewind), purchase of a new rotor or purchase of a spare rotor in cases of multiple identical units at a plant.

In the financial evaluation of stator and rotor rewinds, replacements, or purchase of spare components, there are benefits from the expected enhanced reliability of the generating unit in future service. For this alternative LCM plan, the future failure rates of the stator winding and rotor winding shown in Table 7-7 have been estimated to be lower than in alternative 1B.

Table 7-7
Lost Power Generation and Repair Cost, Alternative 1C

Component	Plant Failure Rate Per Year	Average Outage Duration H	Lost Power Generation Cost $K	Repair Cost Per Failure $K	Repair Cost $K/Year
Stator Winding	0.01	720	360	800	8.0
Rotor Winding	0.01	480	240	500	5.0
Exciter and AVR	0.035	48	84	20	0.7
Other (Hydrogen cooler)	0.026	24	31	10	0.3
Total			715		14.0

In alternative 1C, there are capital investment costs of rewinding two stators and one rotor, and the purchase of a new rotor. The new and the rewound rotors are put in-service and the displaced rotor is to be used as a spare for both units. The costs of the new rotor and rotor rewind are averaged between the two units to keep the cost per unit at an equivalent level. These costs are calculated at:

Stator rewind: $8.0M

Purchase new rotor: $7.0M

Rotor rewind: $5.0M

Rotor cost per Unit: $6.0M

Increased yearly PM costs from increased outage costs are $25,000, as in alternative 1B.

The difference in the yearly cost of loss of power generation between base case 1A and Alternative 1C is about $1.92M. Although the PM cost increases by $25,000 per year, the total yearly savings are about $1.89M with an investment of $14.0M.

When performing the actual analyses using the Net Present Value (NPV) method, it is important to model the timing decisions of component rehabilitations or replacements correctly. The original maintenance activities and failure rates continue until the time of a component replacement, or until its reconditioning is implemented. Benefits, such as reductions in failure rates, reduced lost power generation and lower cost of alternative PM activities, are realized only after replacements or rehabilitations have been made.

The EPRI LCM planning tools (LcmPLATO [26] or LcmVALUE) [27] can be employed to determine the alternative costs on an NPV basis. The tools are capable of handling fairly complex models, including non-linear failure assumptions and phasing in and out of individual tasks over time.

These costs are based on one unit analysis. If the generator exciter outage data on another unit are the same, or similar, the above costs can be simply doubled to obtain the total plant cost information. If reliability data between units are significantly different, a separate cost analysis for each unit should be conducted. Different LCM Plans may be adopted for each unit.

It should be stressed that the data used in the above example are hypothetical and are intended for demonstration purposes only.

8
GUIDANCE FOR ESTIMATING FUTURE FAILURE RATES

This section addresses, in part, step number 18 of Figure 2-2. Failure rates are an important 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 [3]. Below are some useful ideas for estimating failure rates in generator LCM planning studies.

Table 6-2 provides the estimated "Useful Life of Generators and Exciters". These data may be used to estimate the expected remaining life of the main generator components and parts. If "in-kind" replacements are made, existing failure rates may be applied for the future. Components with significant design improvement may be assigned an improved failure rate, if data are available to support such assessment, e.g. a well-documented design review or statistical failure data of components incorporating the new design. Following is a general guide for estimating the future failure rates of rewinds/replacements:

- The replacements with "in kind" parts do not justify changes in the plant-specific failure rates. The average random failure rate of a component remains the same over the whole normal operating life under the same maintenance and operating conditions.
- The rewind of a rotor or stator winding is normally justified in order to correct identified generic design or assembly problems. The reconditioned or new components, such as new stator winding or re-insulated rotor winding, are deemed to incorporate the available design improvements and technological enhancements. The plant-specific future failure rate of such components would be expected to improve and perform in the range of industry average failure rate for the components.
- A decision to re-wind or replace a rotor with a new rotor will depend on the assessment of the condition of the rotor forging. Low or high cycle fatigue crack initiations in stress concentrated regions and their propagation in-service are the main risks to forging integrity. Although four pole nuclear generator rotors are mechanically stiffer than two pole rotors, fretting fatigue crack initiations has been recorded at radial stud retaining nuts, at lead wedges and at wedge ends on top of winding teeth. Westinghouse and GE have reported incidents of such cracking; although it is not yet clear how widely it is applicable to the whole fleet of rotors. The risk of such cracking increases in rotors that are subjected to incidents of high negative sequence currents, occurring during power system imbalances or during transformer, breaker and line faults close to generating plants. The negative sequence currents overheat the rotor surfaces and may reduce the strength properties of the rotor steel.

- The purchase of a new rotor instead of a rewind may also be justified in instances where rewinds cannot be completed within the planned outages, thus causing unit outage extensions and loss of production. The cost of a fully machined forging is on the order of 20% of the final rotor cost. The cost of a new rotor vs. rotor rewind can thus be justified against a few days of unit production loss.
- The design and technological enhancements of a new part that is clearly superior to the replaced part may justify a failure rate that is lower than the industry average. Such predictions can only be made as an engineering judgment, as it is not likely that the new component type would have a significant statistical record.
- Major spares, such as a spare rotor, stator, cooler, bearings, hydrogen seals, exciter, and AVR card, all have a strong effect on reliability improvements. The main advantage of spares is the reduction in outage duration from repair time to replacement time. In U.S. plants, the replacement of degraded, but not failed parts, can be completed within planned outages, thus entirely avoiding some on-line failures. Plants with major spares normally perform at better-than- average industry failure rates.

Corrective Work Orders (WOs) provide both information for root cause analysis and data for computing failure rates. Caution is needed when reviewing WOs, because some plants consider generator overhaul as corrective maintenance. In general, only failures causing forced unit outages or extensions to planned outages should be considered. The plant-specific generator failures should be readily available from the records of events of reactor scrams, trips and deratings. These records should be examined and generator outage contributions extracted. The PRA/PSA data normally do not cover generator forced outages and may not be a good source of generator outage data. The WO review should encompass at least the previous 5 years of data to generate meaningful results. The projection of the past plant-specific failure rates into the future may not be valid on components that have been modified and the root cause problems corrected. An engineering assessment of the modifications is in order for estimation of future failure rates.

Generator failure rates do not have a large statistical base and do not provide for clear and confident extension of past performance into the future. The evaluation of future failure rates should be based on strong engineering assessment of design features and their impact on future degradation. This can be done with the help of OEMs or experienced consultants.

Failure rate reduction can be achieved by implementation of redundant components in control and monitoring circuits in the exciter and in other auxiliary equipment. If the LCM plan considers such design changes, future failure rate projections must consider the effect of redundancy, as discussed in the LCM sourcebook overview report [3]. The excitation controls and voltage regulators may contain significant number of such redundant circuits. The new digital processors, multiple channel redundancy, self-checking circuits, and self-diagnostic fault features provide a strong incentive for modernizing the control and protection devices.

Design margins in main generator components, such as the stator winding, stator core, and rotor are powerful means of reliability improvements. Realization of increased margins may be difficult, because new components need to fit into the existing geometry. However, increasing design margins may be feasible with stator winding replacements and rotor rewinds. Such optimization requires detailed calculations of generator parameters, which are generally available only from the OEM.

The increase in unit output through higher steam supply and/or increase in turbine efficiency have generally negative effects on generator reliability. The effect of thermal aging can be largely mitigated by the adjustment of the generator power factor.

Changes in operating conditions may affect generator availability. Changes in starting and loading cycles increase the strain and thermal stress transients in windings, winding supports and core clamping pressures, thus accelerating degradation. Changes in the power system configuration will increase the line fault levels near the generators. During fault events, such as line single-phase faults, the fault currents through the generator winding will place increased stresses on the winding. This increased stress will cause insulation cracking and the relaxation of winding supports. Undetected damage from such events can significantly increase risk of unforeseen and sudden generator faults.

Purchase of major generator spares, such as spare rotor, stator, or exciter, does not improve the failure rates of the spares themselves, unless significant design enhancements have been incorporated in the spares. However, a significant reduction in the outage duration (and lost power generation) can be achieved when component replacement times are shorter than component repair times. These should be evaluated separately before being used in calculations of repair costs and unit production losses.

The generator systems in different plants may not include the same scope of equipment; in some cases the generator and exciter are not in the same systems, in others, the generator system may include exciters, a voltage regulator, protection and control circuits, relays, IPB, and all generator auxiliaries. LCM planning should clearly define the equipment systems covered. It may not be advantageous to include too many systems with the generator and exciter. If too many systems are included, the plant-specific generator reliability records may become too unique to a specific plant and therefore, no longer comparable to industry benchmark data or any other comparative index.

In summary, failure rate predictions for plant-specific generator and exciter components are made using the above guidance and the generic guidance presented in Section 2.6 of the LCM sourcebook overview report [3]. 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.

The following failure rates were developed in LCM Plans for Main Generators at STARS plants [2]. They are shown here for illustration. Each plant's generator was divided into four major components: Stator (including core, stator winding, winding insulation and terminal bushings), Rotor (including rotor winding, rotor forging and retaining rings), Exciter (including rotating exciter, static rectifier and voltage regulator) and Other (including hydrogen coolers and seals, bearings, slip rings and brush gear). The estimated failure rates for stators and rotors are presented in Table 8-1.

Table 8-1
Generator Stator and Rotor Failure Rates Applied in STARS LcmVALUE Inputs

Plant	Stator Failure Rates						Rotor Failure Rates					
			Alternatives						Alternatives			
	INFR	PSFR	1A	1B	1C	1D	INFR	PSFR	1A	1B	1C	1D
DC-1	0.016	0.120	0.060	0.030	0.015	0.030	0.010	0.060	0.030	0.020	0.015	0.015
DC-2	0.016	0.120	0.060	0.030	0.030	0.015	0.010	0.060	0.030	0.020	0.010	0.010
WC	0.016	0.120	0.100	0.060	0.030	0.016	0.010	0	0.030	0.030	0.030	0.030
STP	0.016	0.038	0.038	0.038	0.038	0.038	0.010	0	0.010	0.010	0.010	0.010
CP	0.016	0	0.015	0.010	0.010	0.010	0.010	0.048	0.040	0.025	0.010	0.010
CAL	0.016	0.110	0.060	0.020	0.016	NA	0.010	0	0.030	0.020	0.010	NA
APS	0.016	0.022	0.030	0.020	0.020	0.015	0.010	0	0.030	0.020	0.015	0.015

INFR= Industry Failure Rate

PSFR=Plant-specific Failure Rate

DC – Diablo Canyon, WC – Wolf Creek, STP – South Texas Project,

CP – Comanche Peak, CAL – Callaway, APS – Palo Verde

The Industry Failure Rates are from the analysis of NPRDS/EPIX data as shown in Section 4.1.1, Table 4-2.

The Plant-specific Failure Rates are from the forced outage failure data collected at each plant. The failure rates used in LcmVALUE analysis inputs in each Base Alternative (1A) were evaluated on the basis of already completed corrective maintenance actions and the current preventive maintenance program and plans. Based on these plans, a reduction of the future failure rates from past experience is justified in many instances. In cases where no failures were recorded on stator and rotor windings in the past, zero failure rates are shown in the plant-specific column. However, it was considered unlikely that such a record could be sustained to the end of the plant life. The future failure rates were estimated from the current winding condition assessment and from the operating experience on generators of similar design at other plants.

The failure rates in the examined alternatives (1B to 1D) were evaluated on the basis of the merits of the proposed preventive maintenance actions for future operating periods. Examples of such actions are:

- Implementation of enhanced on-line monitoring for early detection of developing problems, such as: increase in winding temperatures, winding vibration, cooling water leaks, rising trend in partial discharge activity, and indication of shorted turns in rotor winding. Although the mere detection of such degradation does not improve the generator condition, the improvements in failure rates are justified, where condition based PM is in place, which prevents forced outages and lost production. In some cases, refurbishment can be done during refueling outages so that the impact of maintenance is much less than for a forced outage.
- Major upgrades, global leak repairs, rewinds, upgrade to digital controls, and purchase of major spares significantly reduce the estimated future failure rates. Here a distinction can be made between repairs/replacements with in-kind design/materials and enhanced designs, where generic failure mechanisms have been eliminated. In some instances it is even justified to assume lower failure rates than the average industry failure rates.

In plant-specific analyses, components may be grouped differently than in the hypothetical case in this report, depending on plant experience with a particular component and the plan in place to remedy poor performance of that component. For instance, if hydrogen coolers, hydrogen seals or main bearings indicate significant contribution to unit forced outages, it may be useful to identify their past failure rates separately, evaluate the cost of their repairs/replacements and project their future improved failure rates. It is suggested that the components be selected and grouped on the basis of their significance and impact on the unit outage durations, loss of production, and cost of repairs.

9
INFORMATION SOURCES AND REFERENCES

9.1 Information Sources

The references provided below were found to be the most relevant origins of meaningful data. While most of the useful information from these sources has already been mined and summarized in this sourcebook, individual plants may find it useful to interrogate plant-specific data sorts or search for equipment failures under the same vendor, model or size.

1. Institute of Nuclear Power Operations INPO Website, SEE-IN, provides up-to-date information and listings of industry-wide component problems documented in:
   - Operating Experience Reports (OEs)
   - Operations and Maintenance Reminders (O&MRs)
   - Significant Event Reports (SERs)
   - Significant Event Notifications (SENs)
   - Significant Operating Experience Reports (SOERs)
2. Institute of Nuclear Power Operations NPRDS and EPIX Databases provide equipment failure reports and sorts by equipment code, system code, vendor, failure mode, plant, etc.
3. EPRI Workshop and Maintenance Conference Reports provide guidance for maintaining the integrity and reliability of large generators. These reports concentrate on specific generic issues of generator performance from a user perspective.

9.2 References

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22. Guide for On-Line Testing and Monitoring of Turbine Generators, EPRI Report 1006861, March 2002.

23. *Primer on Maintaining the Integrity of Water-Cooled Generator Stator Windings*, EPRI, September 1995. Report TR-105504.

24. Lowther, Gary R., ”Root Cause Investigation of Core Loosening Incident at South Texas 2, 84P0816 January, 1996”, Siemens-Westinghouse Report, February 8, 1996.

25. WORL-TR-91056: S-W Refueling and Warranty Inspection Report for Huston Lighting and Power Company, South Texas Project, Unit 1, April 1, 1991.

26. “Partial Discharge Test Results for South Texas Project Unit 2”, IRIS Power Engineering Report, August 2, 2000.

27. Lori Rux, “Ramped High-Voltage DC Testing: A Refined Method of Evaluating Stator Winding Insulation”, IEEE Power Engineering Society Panel Session on High Voltage Testing of Rotating Machines, 97TP119-0.

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Program:
Nuclear Power

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