ELECTRIC POWER RESEARCH INSTITUTE

Wind Turbine Maintenance Guide

2012 TECHNICAL REPORT

Wind Turbine Maintenance Guide

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1024891
Final Report, July 2012

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Sequoia Consulting Group, Inc.

NOTE

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Acknowledgments

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

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This report describes research sponsored by EPRI.

EPRI would like to acknowledge the members of the Technical Advisory Group for this report:

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EPRI would also like to acknowledge the Operations and Maintenance team of the Los Angeles Department of Water and Power, Pine Tree Wind Power Project, Bakersfield, California. These individuals were instrumental in sharing maintenance practices and lessons learned to facilitate the development of this report.

This publication is a corporate document that should be cited in the literature in the following manner:

Wind Turbine Maintenance Guide. EPRI, Palo Alto, CA: 2012. 1024891.

Product Description

This guideline provides component-level information regarding the maintenance of major components associated with a wind turbine. It combines recommendations offered by major equipment manufacturers with lessons learned from owner/operators of wind turbine facilities.

Background

With the rush to develop today's massive wind energy sites, little attention is being paid to the inevitable need to perform routine maintenance and develop practical means of assessing the condition of the components within the nacelles and other outside support equipment for the wind farms. Current operating models have not adequately established accurate assumptions or expectations on the unavailability of the windmills and the impact on lost generation. Contracts for purchase of their generation output are being affected by these losses, causing increased concern on overall reliability. The current business model is not adequately focused on equipment health and reliability as seen in more conventional power generation facilities.

There is a developing concern among the owners that generation revenues are being lost at much higher rates than expected due to unavailable machines. Machines that are offline for long periods due to equipment degradation and failures do not generate revenues to pay back the owners' investments. Even though these machines may have equipment warrantees or maintenance agreements, there are no warranties or liquidated damages for lost generation sales when a windmill is offline due to an unexpected outage.

Objectives

The primary objective of this technical report is to provide maintenance guidance that exceeds that typically provided by the original equipment manufacturers (OEMs) of wind turbines, thus allowing significant strategic improvements by:

- Reducing maintenance-related operation and maintenance (O&M) costs by ensuring complete understanding of the technology

- Improving equipment reliability through more detailed maintenance guidance on critical equipment

- Providing recommendations on preventive maintenance optimization to avoid unnecessary expenditures

- Preserving equipment knowledge for workers, necessitated by industry turnovers

Approach

The Electric Power Research Institute (EPRI) worked with a collaboration of owners, operators, OEMs, and vendors to develop tactical guidance on monitoring, predicting remaining life, condition-based maintenance, O&M program models, and supply chain programs including third-party supply and refurbishment services.

Results

This technical report provides comprehensive insights for managers of wind turbine facilities to effectively address on-going maintenance issues. The report provides an overview of system design parameters and familiarizes the user with the components that make up a typical wind turbine and their functions, but the focus of the report is on providing site personnel with both insight regarding various failure mechanisms and detailed guidance for performing preventive maintenance on the numerous system components of a wind turbine. The report also provides guidance regarding the repair and replacement of system components, the components that are typically repaired or refurbished on site, and troubleshooting guidance.

Applications, Value, and Use

This guideline can be used to develop in-house maintenance crews, provide training for contract maintenance travelers to overcome the loss of knowledge due to turnover, and provide a consistent maintenance program for components and parts on the wind farms and in the nacelles. By developing a reliability-based program using standard guidelines, owners can use it as a strength in bidding maintenance to a larger resource pool, or it can be used as a basis for specifying long-term maintenance contracts that can be relied upon and to assist in stabilizing projected maintenance costs.

Keywords

Gearbox
Maintenance
Turbine
Generator
Nacelle
Wind

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Section 1: Introduction

1.1 Background

With the rush to develop today's massive wind energy sites, little attention is being paid to the inevitable need to perform routine maintenance and develop practical ways to assess the condition of the components within the nacelles and other outside support equipment for the wind farms. Current operating models have not adequately established accurate assumptions or expectations on the unavailability of the windmills and the impact on lost generation. Contracts for purchase of their generation output are being affected by these losses, causing increased concern regarding overall reliability. The current business model is not adequately focused on equipment health and reliability as seen in more conventional power generation facilities.

There is a developing concern among the owners that generation revenues are being lost at much higher rates than expected due to unavailable machines. Machines that are offline for long periods due to equipment degradation and failures do not generate revenues to pay back the owners' investments. Even though these machines may have equipment warrantees or maintenance agreements, there are no warranties or liquidated damages for lost generation sales when a windmill is offline due to an unexpected outage.

1.2 Objectives

The Electric Power Research Institute (EPRI) worked with a collaboration of owners, operators, original equipment manufacturers (OEMs), and vendors to develop tactical guidance on monitoring, predicting remaining life, condition-based maintenance, operation and maintenance (O&M) program models, and supply chain programs including third-party supply and refurbishment services. This guideline can be used to develop in-house maintenance crews, provide training for contract maintenance travelers to overcome the loss of knowledge due to turnover, and provide a consistent maintenance program for components and parts on the wind farms and in the nacelles. By developing a reliability-based program using standard guidelines, owners can use it as a strength in bidding maintenance to a larger resource pool, or it can be used as a basis for specifying long-term maintenance contracts that can be relied upon and assist in stabilizing projected maintenance costs.

This guideline provides component-level information whose functional details will exceed most that is provided by the OEMs, thus allowing significant strategic improvements by:

- Reducing maintenance-related O&M costs by ensuring complete understanding of the technology
- Improving equipment reliability through more detailed maintenance guidance on critical equipment
- Providing recommendations on preventive maintenance optimization to avoid unnecessary expenditures
- Preserving equipment knowledge for workers, caused by industry turnovers

1.3 Contents of the Report

Figure 1-1 illustrates the general structure and content of this technical report. The figure identifies key sections in the report that provide guidance to owners to effectively address wind turbine system component maintenance issues.

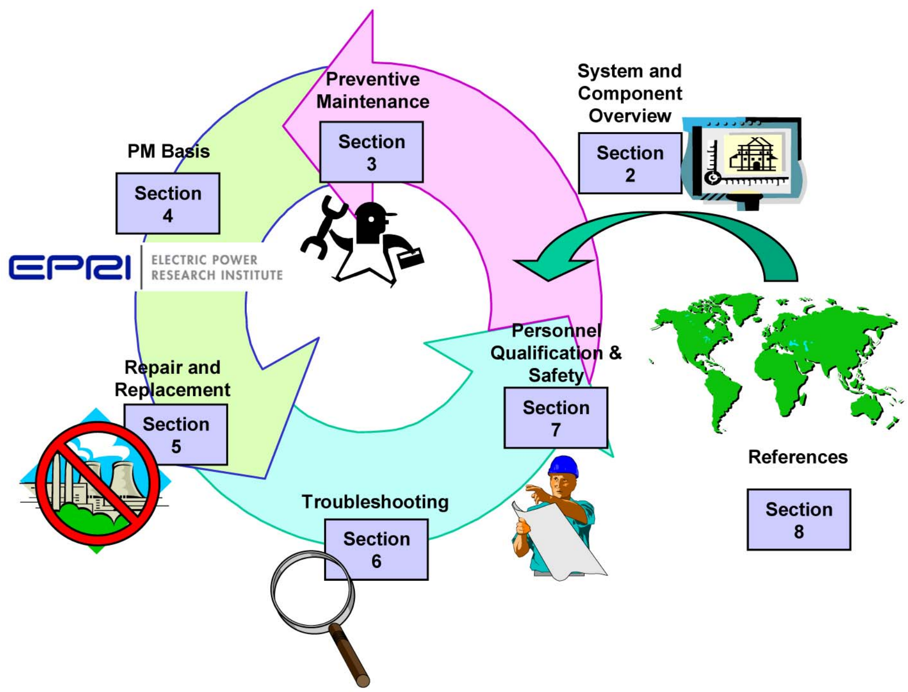

Figure 1-1
Scope and content of this EPRI report (original PowerPoint drawing)

This section provides an introduction to the report, and Section 2 provides an overview of system design parameters and familiarizes the user with the components that make up a typical wind turbine and their functions. The focus of the report is Sections 3 and 4, which provide insight to various failure mechanisms and detailed guidance for performing preventive maintenance on the numerous system components. Section 5 provides guidance regarding the repair and/or replacement of system components, and which components are typically repaired or refurbished on site. Section 6 provides the owner with troubleshooting guidance. Personnel safety guidelines are provided in Section 7, and Section 8 provides the user with a complete listing of references that were used during the development of this report.

1.4 Definitions of Key Terms and Acronyms

1.4.1 Industry Definitions and Nomenclature

corrective maintenance	Maintenance tasks that are generated as a result of equipment failure. Corrective tasks are generated when equipment is purposely operated to failure and also when equipment failure is not wanted or planned. It is the most basic form of maintenance and also the most expensive. Most plants are moving away from corrective maintenance, but there will always be a portion of maintenance being performed as a result of equipment failure.
elective maintenance	The classification of any work on power block equipment in which the identified potential or actual degradation is minor and does not threaten the component's design function or performance criteria.
facilities	Structures, systems, and components not associated with power generation. Structures may include training facilities, warehouses, maintenance shops, and administrative offices. Systems may include fire protection, plumbing, lighting, sewer, and drainage.
monopile	A single totally enclosed structure that supports the nacelle and is mounted on a deep-buried reinforced concrete pad using hydraulically tensioned bolted fasteners.
periodic maintenance	"Time-based" preventive maintenance actions taken to maintain a piece of equipment within design operating conditions and to extend its life.
predictive maintenance	Maintenance tasks that are performed based on equipment condition. Predictive maintenance relies on technologies to determine the current condition of the equipment so that only the required maintenance is performed before equipment failure.

preventive maintenance	Maintenance tasks that are performed based on a time or interval basis to avoid catastrophic equipment failure. Preventive maintenance performs maintenance tasks on a planned rather than reactive basis and avoids the losses associated with unplanned downtime. The penalty of preventive maintenance is that some tasks are performed that are unnecessary and costly.
proactive maintenance	Maintenance tasks that determine the root cause of an equipment problem. Chronic problems require advanced technologies, additional resources, and time to provide a final solution for an equipment problem. The problem can be the result of poor design, inadequate maintenance practices, or incorrect operating. procedures.
qualified individual	For the purposes of concurrent verification and independent verification, a person who has been determined by station management to be qualified to perform verification activities. As a minimum, this individual shall be trained in human performance verification techniques.
work instruction	Instructions for performance of the work to be accomplished, the level of detail of which is dependent on the assigned planning level. When applicable, approved procedures may be referenced and may suffice as work instructions.
work order	A document used to control work and/or testing activities.

1.4.2 Acronyms

AGMA	American Gear Manufacturers Association
AWEA	American Wind Energy Association
CCO	certified crane operator
CFRP	carbon filament-reinforced-plastic
DC	direct current
DIN	Deutsches Institute für Normung
EPRI	Electric Power Research Institute

ESR	electrostatic re-melt
ET	eddy current test (also ECT)
FAA	Federal Aviation Administration
GRP	glass-reinforced plastic
GW	gigawatt
HAWT	horizontal-axis wind turbine
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IGBT	insulated gate bipolar transistor
ISO	International Standards Organization
kW	kilowatt
LCF	low cycle fatigue
MPT	magnetic particle test
MW	megawatt
NASA	National Aeronautics and Space Administration
NDE	nondestructive examination
O&M	operation and maintenance
OEM	original equipment manufacturer
OSHA	Occupational Safety and Health Administration
PBT	polybutylene terephthalate
PC	printed circuit
PFAS	personal fall arrest system
PI	polarization index
PLC	programmable logic controller
PM	preventive maintenance
REPP	Renewable Energy Policy Project

RSO	recurrent surge oscillography
RTD	resistance temperature detector
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCR	silicon controller rectifier
TDR	time domain reflectometry
TVP	turbine verification program
UPS	uninterruptable power supply
VAR	vacuum arc re-melt
VAWT	vertical-axis wind turbine
WTG	wind turbine generator

1.5 Listing of Key Points

Throughout this report, key information is summarized in Key Points. *Key Points* succinctly restate information covered in detail in the surrounding text, making the key point easier to locate.

The primary intent of a Key Point is to emphasize information that will allow individuals to act for the benefit of their plant. Electric Power Research Institute (EPRI) personnel who reviewed this report assisted in the selection of the information included in these Key Points.

The Key Points are organized into three categories: Human Performance, O&M Cost, and Technical. Each category has an identifying icon to draw attention to it for the benefit of readers who are quickly reviewing the report. The Key Points are shown in the following way:

Key Human Performance Point
Denotes information that requires personnel action or consideration in order to prevent personal injury, prevent equipment damage, and/or improve the efficiency and effectiveness of the task.

Key O&M Cost Point
Emphasizes information that will result in overall reduced costs and/or an increase in revenue through additional or restored energy production.

Key Technical Point
Targets information that will lead to improved equipment reliability.

Key Supervisory Observation Point
Identifies tasks or series of tasks that can or should be observed by maintenance first line supervisors to improve the performance of the maintenance staff and improve the reliability of the component.

Appendix A of this report contains a listing of all Key Points in each category. The listing restates each Key Point and provides a reference to its location in the body of the report. By reviewing this listing, users of this report can determine if they have taken advantage of key information that the writers of this report believe would benefit their plants.

1.6 Advantages and Challenges of Wind Energy

Wind energy offers many advantages, which explains why it is the fastest-growing energy source in the world. Research efforts are aimed at addressing the challenges to greater use of wind energy.

1.6.1 Advantages

Wind energy is fueled by the wind, so it is a clean fuel source. It does not pollute the air like power plants that rely on combustion of fossil fuels, such as coal or natural gas. Wind turbines do not produce atmospheric emissions that cause acid rain or greenhouse gases.

It is a domestic source of energy, produced in the United States. The nation's wind supply is abundant.

Wind energy relies on the renewable power of the wind, which cannot be used up. Wind is actually a form of solar energy; winds are caused by the heating of the atmosphere by the sun, the rotation of the earth, and the earth's surface irregularities.

It is one of the lowest-priced renewable energy technologies available today, costing between 4¢ and 6¢ per kilowatt-hour, depending upon the wind resource and financing of the particular project.

Wind turbines can be built on farms or ranches, thus benefiting the economy in rural areas, where most of the best wind sites are found. Farmers and ranchers can continue to work the land because the wind turbines use only a fraction of the land. Wind power plant owners make rent payments to the farmer or rancher for the use of the land.

Key Human Performance Point
Owners of wind turbine facilities should estimate having approximately one full-time technician for every seven to eight wind turbines in their fleet.

1.6.2 Challenges

Wind power must compete with conventional generation sources on a cost basis. Depending on how energetic a wind site is, the wind farm may or may not be cost competitive. Even though the cost of wind power has decreased dramatically in the past 10 years, the technology requires a higher initial investment than fossil-fueled generators.

Good wind sites are often located in remote locations, far from cities where the electricity is needed. Transmission lines must be built to bring the electricity from the wind farm to the city.

Key Technical Point
Off-site power is needed in order to start generation of electricity. A wind turbine cannot start generating electricity as soon as the wind starts blowing.

Wind resource development may compete with other uses for the land, and those alternative uses may be more highly valued than electricity generation.

Although wind power plants have relatively little impact on the environment compared to other conventional power plants, there is some concern over the noise produced by the rotor blades, aesthetic (visual) impacts, and sometimes birds and bats have been killed by flying into the rotors. Most of these problems have been resolved or greatly reduced through technological development or by locating wind plants on appropriate sites.

Key Technical Point
Extreme care should be taken when de-energizing a wind turbine because computer hard drive failures may occur.

Key O&M Cost Point
When purchasing a fleet of wind turbines, it is not uncommon that a given subcomponent (for example, pitch drive, gear drive, bearings, generator bearings, etc.) will be furnished by different manufacturers. Consequently, it is possible that no two wind turbines will be identical. This can directly affect the scope and frequency of maintenance activities (for example, different gearboxes may use different types of grease).

Key O&M Cost Point
When purchasing a fleet of wind turbines that do not all have the same exact subcomponents, it is beneficial to request a subcomponent list (bill of material) for each wind turbine in order to optimize maintenance activities.

1.6.3 Commissioning a Wind Power Turbine

There are many different contractual arrangements under which an owner can procure, construct, and commission a wind turbine power plant. Although this subject is primarily outside the scope of this report, the following Key Points were learned while visiting wind turbine facilities during the development of this report and should be considered by prospective wind farm owners/operators.

Key Supervisory Observation Point

During the commissioning of a fleet of wind turbines, care should be taken to ensure that the commission teams are performing activities consistently and accurately and that quality control personnel are providing oversight **in** the towers as the teams are performing commissioning activities.

Key O&M Cost Point

Turnover of wind turbines during commissioning should be staggered so that the entire fleet is not turned over at the same time. Individual wind turbine commissioning turnover causes the owner to do 30-day maintenance activities all at once in order to remain in warranty, which puts unnecessary scheduling and staffing demands on the owner when scheduling/optimizing planned maintenance activities.

Key Technical Point

Brake adjustment is a critical activity that should be integral to and performed during commissioning.

Key O&M Cost Point

Care should be taken when procuring maintenance kits from the original wind turbine manufacture because not everything typically included in a kit will be needed (for example, brake pads).

Key Technical Point

Specialty tools used for greasing and torquing typically have long lead times for delivery. This should be considered during initial procurement and maintenance planning and might need to be factored in to the site's tool calibration and rotational use program.

Key Technical Point

Portable electric generators might be needed when there is a loss of on-site power to perform regularly scheduled maintenance activities.

Section 2: System Description

The purpose of this section is to provide owner maintenance and engineering personnel with an overview of wind turbine design, failure mechanisms, and construction.

2.1 Types of Wind Turbines

Today's utility-scale wind turbines are predominately based on a horizontal-axis wind turbine (HAWT) design. In this type of design, the axis of rotation is parallel to the ground. A competing class of wind turbines is based on the use of the axis of rotation perpendicular to the ground, the vertical-axis wind turbine (VAWT). As will be discussed later, the utility-scale VAWT has disappeared from the current commercial market.

HAWT rotors are usually classified according to the rotor orientation to the tower (upwind or downwind), hub design (rigid or teetering), rotor control (pitch or stall), number of blades (usually three or sometimes two blades), and how they are aligned with the wind (free yaw or active yaw).

The principal subsystems of a typical HAWT include the following:

- The rotor – This consists of the blades and supporting hub.
- The drive train – This includes the rotating parts of the wind turbine (except the rotor); it usually consists of shafts, a gearbox, couplings, a mechanical brake, and a generator.
- The nacelle and main frame – This includes the wind turbine housing, bedplate, and the yaw system.
- The tower and the foundation.
- Machine controls.
- Balance of the electrical system – This includes cables, switchgear, transformers, and power electronics.

Design variations in these components form various wind turbine layouts or "topologies." In general, these include the following choices:

- Number of blades (usually 2 or 3).
- Power control – This includes stall, variable pitch, controllable aerodynamic surfaces, and yaw control.
- Rotor position – Upwind or downwind of tower.

- Rotor speed – Constant or variable.
- Yaw control – Driven yaw, free yaw, or fixed.
- Design tip speed and blade solidity.
- Type of hub – Rigid, teetering, hinged blade, or gimbaled.
- Number of brakes.

2.2 Sizes of Wind Turbines

Utility-scale turbines range in size from 100 kilowatts (kW) to as large as several megawatts (MW). Larger turbines are grouped together into wind farms, which provide bulk power to the electrical grid.

Single small turbines, less than 100 kW, are used for homes, telecommunications dishes, or water pumping. Small turbines are sometimes used in connection with diesel generators, batteries, and photovoltaic systems. These systems are called hybrid wind systems and are typically used in remote, off-grid locations, where a connection to the utility grid is not available.

The majority of wind turbine capacity presently installed or under construction are HAWTs with rotor diameters between 60 and 90 meters (m) (197 and 295 feet) with rated capacities ranging from 1 to 3 MW.

Figure 2-1 illustrates the major components of a typical wind turbine.

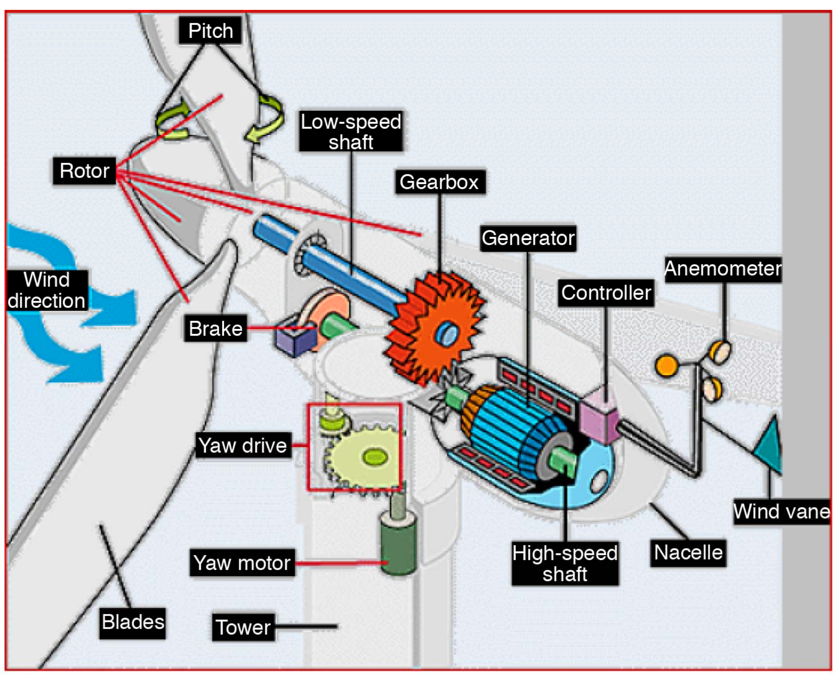

Figure 2-1
Wind turbine components
(U.S. Department of Interior, Bureau of Land Management)

The nacelle includes:

- An outer frame protecting the machinery from the external environment
- An internal frame supporting and distributing the weight of the machinery
- A power train to transmit energy and to increase shaft speeds
- A generator to convert mechanical energy into electricity
- A yaw drive to rotate (slew) the nacelle on the tower
- Electronics to control and monitor operation

Table 2-1
Description of nacelle components
(U.S. Department of Energy, Renewable Energy Policy Project [REPP], Wind Turbine Development)

Subcomponent	Description
Low-speed shaft and high-speed shaft	Transmits rotational work from the rotor hub to the gearbox and from the gearbox to the generator.
Gearbox	Converts low-speed rotation from the input shaft of the rotor to high-speed rotation, which drives the high-speed shaft of the generator assembly. Wind turbine gearboxes typically use a planetary gear system.
Coupling	Attaches the gearbox to the generator. Flexible couplings may be used to reduce oscillating loads that could otherwise cause component damage.
Bearings	A number of bearings are required for the shafts, gearbox, yaw mechanism, generator, and other rotating parts.
Mechanical brakes	A mechanical friction brake and its hydraulic system halt the turbine blades during maintenance and overhaul. A hydraulic disc brake on the yaw mechanism maintains the nacelle position when the nacelle is stationary.
Electrical generator	Converts high-speed shaft work into electrical energy
Power electronics	Couples the generator output to the step-up transformer input, typically with an insulated gate bipolar transistor (IGBT) bridge, allowing the generator to run at variable speed while still outputting 50–60 Hz ac to the grid. Also, makes reactive power possible.
Cooling unit	Drives air with a large fan to convectively cool the generator and gearbox, and exhausts waste heat from the nacelle assembly. Ducting directs cool air to the generator.

Table 2-1 (continued)
Description of nacelle components
(U.S. Department of Energy, Renewable Energy Policy Project [REPP], Wind Turbine Development)

Subcomponent	Description
Yaw mechanism and four-point bearing	Rotates the turbine directly into the wind in order to generate maximum power. Typically, four yaw sensors monitor the wind direction and activate the yaw motors to face the prevailing wind. A four-point bearing connects the nacelle to the tower. The yaw mechanism turns the blades 90 degrees from the prevailing winds under high wind conditions to reduce stress on the internal components and avoid over-speed conditions.
Electronic controllers	(a) A base controller, located at the base of the tower, utilizes printed circuits (PCs) and fiber optics to monitor and record performance data, as well as to facilitate communication between both subcontrollers and external parties. (b) A nacelle controller monitors activity within the nacelle assembly. (c) A hub controller, used in newer models, communicates directly with the nacelle controller to more precisely monitor rotor activity
Sensors	(a) An anemometer, located on the tower, measures wind velocity and relays data to the yaw mechanism. (b) A wind vane measures wind direction and relays data to the yaw mechanism. (c) A cable twist counter monitors cables within the tower to determine if the turbine has been yawing in one direction for an extended period of time. (d) A thermocouple senses temperature within the nacelle assembly.

The rotor includes:

- Blades, which are generally made of glass-reinforced fiber up to 50 m in length. Lighter and stronger carbon fibers are being used in the larger blades.
- Extenders attach the blades to the central hub.
- Pitch drives control the angle of the blades.

The rotor typically has three blades because that number provides the best balance of high rotation speed, load balancing, and simplicity.

Table 2-2
Description of rotor components
(U.S. Department of Energy, REPP Wind Turbine Development)

Subcomponent	Description
Rotor blades	Blades use the principles of lift to convert the energy of the wind into mechanical energy. Stall-regulated blades limit lift, or momentum, when wind speeds are too great in order to avoid damaging the machine. Variable-pitch blades rotate to minimize their surface area and, thereby, regulate rotational speed.
Pitch drive	This system controls the pitch of the blades to achieve the optimum angle for the wind speed and desired rotation speed. At lower wind speeds, a perpendicular pitch increases the energy harnessed by the blades, and at high wind speeds, a parallel pitch minimizes the blade surface area and slows the rotor. Typically, one motor is used to control each blade. Power is either electric or provided by hydraulics in the nacelle and is supplemented by a hydraulic accumulator in the event of system failure.
Extenders	These steel components support the rotor blades and secure them to the hub
Hub	The hub serves as a base for the rotor blades and extenders, as well as a place to house the control systems for the pitch drive. It rotates freely and attaches to the nacelle using a shaft and bearing assembly.

The tower includes:

- Rolled steel tubes connected in series
- Flanges and bolts joining each section
- A concrete base serving as a stable foundation for the turbine assembly

Concrete segmented towers and hybrid steel/concrete towers may also be used for large turbines in cases where steel tower section transportation is difficult.

Table 2-3
Description of tower components
(U.S. Department of Energy, REPP Wind Turbine Development)

Subcomponent	Description
Tower	This component is typically made of rolled tubular steel; it is built and shipped in sections because of its size and weight. Common tubular towers incorporate a ladder within the hollow structure to provide maintenance access. Utility-scale towers range in height from 60 to 100 m and weigh between 182–363 metric tons.
Base	The base supports the tower and transfers the loads to the foundation soil or bedrock. The foundation size and type depend on the foundation conditions, but it is typically constructed with steel-reinforced concrete.
Flanges and bolts	These items join the tower segments.

The balance of wind farm components includes:

- Electrical collection system – Transformer, switchgear, underground and overhead high-voltage cable, and interconnecting substation
- Control system – Control cable, data collection, and wind farm control station
- Roadway, parking, crane pads, and other civil works

Table 2-4
Description of the balance of system components
(U.S. Department of Energy, REPP Wind Turbine Development)

Subcomponent	Description
Electrical collection system	(a) Transformers step up voltage transmission in the collector line to convert energy generated by the turbine into usable electricity for the utility grid. (b) Underground cables are used to connect the power lines until a standard 25-kV overhead collector line can be used. (c) Reclosers and risers act as circuit breakers and isolate a section of the line if there is a power fault. (d) Power substations raise the voltage for standard long-distance transmission.
Communications system	The communications subsystem allows the wind turbines to monitor themselves and report performance to a control station. Data collection equipment and fiber optic cables allow the turbine to monitor and report performance. A control station consolidates data and routes information to the local utility.
Civil works	Crane pads enable the safe operation of cranes during the construction of the turbine, and roads provide access during construction and maintenance activities. Maintenance buildings house workers during construction and overhauls.

2.3 Drive Train Architecture

The wind turbine designs used by generating companies have evolved rapidly since the 1990s. The majority of machines installed in the mid-1990s were rated at 500 kW or less. In the late 1990s, several manufacturers introduced turbines rated at 660–850 kW, and through the year 2000, these dominated the new installations. At that time, the MW-class turbines were introduced, and these machines, rated up to 2 MW, now dominate the industry. Escalation in capacity continues with several manufacturers offering turbines rated at 2.55 MW, primarily aimed at the offshore market, but most of these are still in the development stage, and the installed base is very small.

Despite the rapid increase in rated capacity, the general drive train arrangement of the vast majority of wind turbines installed in the United States since the mid-1990s has remained remarkably consistent. The conventional configuration, shown in Figure 2-1, consists of a main shaft and bearing, gearbox and generator, all mounted on a common bedplate made from ductile iron or fabricated steel. The main shaft is supported by a main bearing on the rotor end and is rigidly connected to the gearbox input stage. This figure depicts a ”three-point” design, where the gearbox case reacts to torque and rotor over-turning moments through arms that are pinned to the mainframe structure. An alternative arrangement uses a second main bearing on the gearbox end of the main shaft to react to over-turning moments; in this case, the gearbox reacts only to main shaft torque through the torque arms.

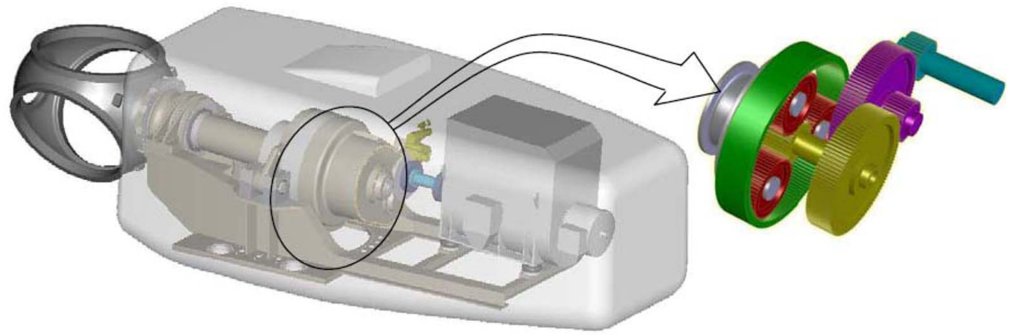

Figure 2-2
Typical wind turbine drive train with three-stage planetary/helical gear arrangement [2]

A flexible coupling, which can be a Cardan shaft in smaller machines, connects the generator shaft to the high-speed output of the gearbox. The brake disc is installed on this shaft. The generator is located on compliant isolation mounts to minimize shock loading and noise transmission into the bedplate. The gearbox torque arms are also usually connected to the mainframe with some sort of compliant bushing.

The conventional gearbox design has three gear stages, with a planetary low-speed section coupled directly to helical, parallel-shaft, intermediate- and high-speed stages. Since the turbine rotor speed varies inversely with the rotor diameter and rated capacity, the gearbox speed ratio increases with turbine rated power, ranging from the high 60s for a 650-kW machine to the high 90s for a 1500-kW machine. Altogether, the gearbox contains 9 gears and between 11 and 16 rolling-element bearings. Lubrication is always provided by a filtered circulating system, with direct oil supply to the bearings and gears, although in some designs, the planet mesh and bearings are lubricated as they pass through an oil sump.

Two types of generators are used in commercial wind turbines, depending on the type of speed and/or power control employed. Turbines with constant rotor speed use standard induction (asynchronous) generators. Variable-speed turbines generally use doubly fed induction generators that feed only a part of the current through the power converter. Although this limits the overall speed range, the cost for the power converter with this scheme is significantly less than the cost for a converter that can handle the entire generator current. From a mechanical standpoint, both types of generator are much the same, with a straddle-mounted rotor supported by a bearing at either end. Lubrication is always with grease.

2.4 Materials Used in Wind Turbines

A wind turbine consists of the following:

- A rotor that has two or three wing-shaped aerodynamic blades that are attached to a hub
- A nacelle that houses a gear train consisting of a gearbox, connecting shafts, support bearings, the generator, plus other machinery
- A tower
- Ground-mounted electrical equipment

A 2001 report of the percentage of different materials used in large wind turbines is given in Table 2-5.

Table 2-5
Percentage of materials used in large wind turbines by weight

Component	Pre-Stressed Concrete	Steel	Aluminum	Copper	Fiberglass Reinforced Plastic
Rotor					
Hub	-	100	-	-	-
Blades	-	5	-	-	95
Nacelle					
Gearbox	-	98	<2	<2	-
Generator	-	65	-	35	-
Frame Machinery and Shell	-	85	8	4	3
Tower	2	98	-	-	-

Clearly, steel is the material of choice for all components except the blades, which are currently primarily glass-reinforced plastic (GRP). The fibers are usually E-glass (a calciumaluminosilicate glass), although some experiments have been performed with S-glass (a calcium-free aluminosilicate glass), which is significantly stronger but much more expensive. New glass fiber compositions such as Owens-Corning HiPer-tex, which claims the strength of S-glass with a cost near E-glass, seem promising. The matrix materials in the GRP composites are mainly thermosets: either polyesters, vinylesters, or epoxies, although polybutylene terephthalate (PBT) thermoplastic is being promoted by Cyclics Corporation. Thermoset polymers are crosslinked in place, usually giving greater strength and a larger elastic modulus than thermoplastics, although at the expense of recyclability. Thermoplastics return to a viscous liquid state above the glass transition temperature, while thermosets usually decompose first.

2.4.1 Rotors and Blades

As blades have grown to 50+ meters in length and weights of 17+ metric tons, they have come to be important both in the cost of the wind machines and in the total tower head mass, which ranges from 310 to about 500 metric tons for 5-MW turbines With these increases has come an increasing need to understand and address the problems experienced by the blades.

The issues involving rotors are many. Foremost, wind turbine rotors must survive more than 108 stress cycles in a 20-year lifetime, so fatigue is a critical issue. Additionally, for the service environment of wind turbines, both creep fatigue and corrosion fatigue are important. These combined phenomena are even less well quantified than ordinary fatigue. These effects show up as cracks and delamination in the composite blades.

Other issues include the following:

- Lightning can cause severe mechanical damage unless adequate protection is built into the blade.
- Rotor imbalance causes even larger stress amplitudes than normal operation, shortening rotor life.
- Aerodynamic asymmetry causes additional vibrations of the nacelle and tower and also causes variations in rotor speed, which may cause a mismatch in the output power waveform.
- Moisture uptake:
    - Causes additional imbalance when non-uniform
    - Enhances creep
    - May attack glass fiber-matrix interface, degrading the material properties of the composite
    - May increase the growth of existing cracks due to cyclical freezing
- Icing causes surface roughness and may increase the growth of existing cracks. Also, it may cause imbalance.
- Surface roughness causes early stall of the airfoil, reducing maximum power output.
- Impact damage during fabrication, transportation, construction, or in service may cause delamination.

2.4.2 Electronic Controls and Power Electronics

Electronic controls and power electronics make up only about 1% of the cost of a wind turbine, but they cause 13% of the failures. The cost fraction argues against doing any condition monitoring at all on the electronics; however, the failure distribution indicates that significant effort in increasing the reliability of the electronics may be warranted, even at significant cost. The problems in electronic controls have many causes, including vibration-induced fatigue of wires and printed circuits, corrosion, water ingress or condensation, and dust. The problems in the power electronics are more often due to thermal management issues due to overload, loss of cooling, or thermomechanical fatigue due to variations in load.

The current systems monitor output voltage, current, and phase, and some monitor temperatures inside the nacelle. Various authors have suggested thermography as a technique to detect overheating components, but no report of its application in service was found in the literature survey.

In 2004, Howard concluded that there was “no significant technology development effort in place” for prognostics in medium-power electronics nor for either diagnostics or prognostics for high-power electronics. He asserted that diagnostics for control electronics is “currently available and proven effective,” while diagnostics for medium-power electronics is “currently available, but verification and validation not completed.” Some early research in addressing the prognosis of electronics has been sponsored by NASA and two programs by the Joint Strike Fighter Program Office. The latter programs have met with limited success, while the former concluded that, particularly for power electronics, the timescales for degradation are too fast for corrective action before failure.

Perhaps redundant controls and power electronics, as used in aerospace applications, are called for in larger and offshore turbines. The electronic systems are unique in wind turbines in that redundancy is achievable within constraints of functionality, volume, and mass. The cost of redundant systems should be considered against the expected loss of revenue, which could be very important in future wind machines. For the hypothetical 12-MW offshore turbine, the cost of the electronic controls and power electronics would be about $100,000. A triply redundant system costing $300,000 would be justified if it could prevent a single day’s lost production in each of the 20 years of service, or a single outage of 20 days during the 20 years of service. Note that for offshore turbines, any unscheduled outage may require many more than 20 days of waiting for acceptable weather to service the turbine. Even for the current 1.7-MW turbine, where the electronics cost about $17,000, a triply-redundant system would be justified if it could prevent the loss of about 30 days’ production in 20 years. Even if triple redundancy is not deemed practical for any current wind turbines, the example above shows that significant resources can be spent on improving reliability by, for example, derating critical components such as power transistors in order to increase their life.

2.4.3 Tower and Foundation

The newest turbines with blades over 50 m long require towers that approach and even exceed 100 m in height. The cost of the tower is decreasing as a fraction of the total cost, reaching 12% for the 3-MW turbine. The fractional cost of the foundation is also decreasing, accounting for only 2% of the cost of the 3-MW turbine. Neither the tower nor the foundation accounted for any of the failures in 10,000 turbine-years of operation.

Nevertheless, with the growth of tower height beyond 100 m, tower head mass beyond 500 metric tons, and continued growth in bending load, some investigation of condition monitoring is warranted. The tower technology currently dominant in the market, the steel monopile, is reaching the limit of its capability. For example, Enercon offers steel towers of 64–98 m for its E-70 turbines, but only prefabricated concrete towers for greater heights.

One industry expert contends that the ideal solution for taller towers would be a steel lattice spaceframe (like the Eiffel Tower), but that this design is limited by fatigue of the joints. Nevertheless, towers employing a welded lattice substructure with a monopile tower are being examined for the Talisman project in the Beatrice wind turbine farm. Management of fatigue in welded and riveted joints is an issue of current research in condition monitoring in civil and aerospace engineering, so this problem may not be insurmountable.

2.4.4 Generators

Generator designs used in wind turbines continue to evolve to produce systems that are simpler, more efficient, and require less maintenance. Table 2-6 provides a compilation of types of generators provided by major wind turbine manufacturers.

Table 2-6
Wind-turbine manufacturers' generator designs

Manufacturer	Generator Features/Design
Coemi	Coemi-G3 turbines claim a very efficient design with a power conversion of 85% because they use an asynchronous generator that is directly connected to the grid with no need for an inverter.
GE Energy	Permanent magnet generator for higher efficiency at low wind speed. Brushless excitation for simplified maintenance.
Northern Power Systems	Permanent magnet (PM) generator.
ENERCON	Annular generator. Among other features, the annular generator is a key component in ENERCON's gearless wind generator design. Combined with the rotor hub, it provides an almost frictionless flow of energy, while a smaller number of moving components ensure minimal material wear. Unlike conventional fast-running generators, ENERCON's annular generator is subjected to little technical wear, making it ideal for particularly heavy loads and a long service life. ENERCON's annular generator is a low-speed synchronous generator with no direct grid coupling. Output voltage and frequency vary with speed and are converted for output to the grid via a dc link and an inverter, which allow for high-speed variability. Advantages of ENERCON's annular generator: •No gear •Low wear due to slow machine rotation •Low machine stress due to high level of speed variability •Yield-optimized control •High power quality According to ENERCON's service life requirements, the copper winding in the stator (the stationary part of the annular generator) known as *closed, single-layer basket winding* is produced in insulation class F (155°C). It consists of individual round wires gathered in bundles and varnish insulated. At ENERCON, the copper winding is done manually. In spite of increasing automation in other manufacturing areas, in this case preference has been given to manual labor for good reason. It ensures that all materials used are fully inspected. Furthermore, a special work process allows continuous windings to be produced. Each wire strand is continuous from start to end.

Table 2-6 (continued)
Wind-turbine manufacturers' generator designs

Manufacturer	Generator Features/Design
ENERCON (continued)	Advantages of continuous winding: • Errors eliminated when making electrical connections • High-quality copper wire insulating system maintained • No contact resistance No weak points susceptible to corrosion or material fatigue
Lagerwey Wind	Direct drive generators
Siemens	The gearbox tends to be the most complex component of a wind turbine; consequently, eliminating the gearbox reduces complexity and increases reliability. Siemens has opted for a permanent magnet generator for improved efficiency. Unlike an electrically excited machine with a gearbox, a permanent magnet-excited machine does not expend any energy on the excitation itself. The SWT-3.0-101 also has an outer rotor, where the rotor spins on the outside of the stator. This design feature allows the rotor to operate within narrower tolerances, which aids in keeping the dimensions of the nacelle compact.
ABB	Low-speed permanent magnet generator In a direct drive application, the turbine and the generator are integrated to form a compact and structurally integrated unit. The design gives free access to all parts for easy installation and maintenance. The simple and robust low-speed rotor design with no separate excitation or cooling system results in minimum wear, reduced maintenance requirements, lower life cycle costs, and a long lifetime.

Section 3: Overview of Wind Turbine Failure Mechanisms

3.1 Component Failure Cost Impact

The turbine drive train components account for between 20% and 25% of initial turbine costs. The expense associated with a failure is compounded by the difficulty of removing and replacing these components. In almost all cases, a crane is required to remove the component, and for some turbines, the entire rotor must be removed in order to access the gearbox. Assuming that a spare unit is available, replacement may take two or three days with a crew of three, plus a crane operator and an oiler. High-wind days, when the wind conditions are too severe to operate the crane, can add to the swap-out time.

The availability of a crane itself can be a major factor in scheduling a gearbox or generator replacement. Sites with smaller turbines on towers less than 65 m in height may be able to use a truck-mounted hydraulic crane to remove the generator and perhaps the gearbox. Since the required crane size is driven for the most part by the lift height, turbines on towers over 70 m will usually require a conventional crane, consisting of perhaps a dozen trailer-truck loads, a helper crane to erect the boom, and two days on either side of the actual lift to assemble and dismantle the main crane. Including the time to travel to and from the site, crane mobilization cost alone can exceed the rebuild cost of the component.

Table 3-1 presents representative costs for replacing generators, main bearings, and gearboxes of conventional turbine configurations. A crane is not required for some repairs, designated by the term “up-tower” in the crane-cost column.

Table 3-1
Representative costs for replacing drive train components

Wind Turbine Size	Tower Height Range (M)	Example Component Failure	Repair cost ($1000)	Crane Cost ($1000)
Kw Class	60 – 70	Gearbox rebuild	$30 - $70	$10 - $40
Kw Class	-	Generator Bearing replacement	$2 - $4	In situ
Kw Class	60 – 70	Generator Rebuild	$10 - $20	$10 - $20
Mw Class	70 – 80	Gearbox rebuild	$60 - $160	$40 - $80
Mw Class	70 – 80	Generator Bearing replacement	$4 - $8	In situ
Mw Class	70 – 80	Generator Rebuild	$30 - $50	$30 - $60

3.2 Component Reliability and Common Failure Mechanisms

The reliability of drive train components for the most recent generation of large kW- and MW- sized machines has not met expectations. Although the components are designed for the 20-year life of the turbine, there are numerous examples in industry of component failures even in the first few years of operation. Some of these failures have been attributed to design or manufacturing faults and have occurred in the first year or two of operation. These have resulted in fleet-wide, or at least project-wide, retrofits or replacements. Other failures have not been as obvious, but are starting to affect projects that are leaving or have left the warranty period.

In this section, degradation of materials used in large horizontal-axis turbines is reviewed. Several mechanisms have been identified: fatigue, creep, creep fatigue, corrosion, corrosion fatigue, wear, fretting, and particle erosion, depending on whether the turbines are largely land-based or offshore.

The most prevalent degradation mechanism is fatigue, due in part to the very large number of cycles, the complex triaxial and variable-amplitude loadings involved, and the large number and types of internal interfaces in the composite material components that are potential weak links. Fatigue degradation of wind turbine materials, with special emphasis on blades, is presented in detail, and attempts to develop predictive methodologies for fatigue life assessment are also reviewed. Offshore turbines with their greater exposure to higher levels of moisture and salt can suffer from degradation of the blades as well as the metallic components of the drive train through such degradation mechanisms as corrosion, corrosion fatigue, creep, and creep fatigue (the creep associated with moisture-induced softening).

First, the various wind turbine materials and their properties are presented with a view to materials selection for turbine blades. Next, degradation mechanisms and actual degradation behavior of candidate materials are reviewed.

The economies of scale are pushing the size of wind turbines beyond 3-MW capacities with rotor diameters on the order of 100 m. This is because power generated is proportional to the rotor's swept area, and the larger power generated per turbine offsets the installation costs associated with tower, foundations, erection, and power collection. These large rotor sizes and the correspondingly large tower heights needed to accommodate such large blades have put severe material demands on turbine components in terms of their allowable weights and the static and dynamic loads that these components will be required to withstand for periods up to 20–30 years (their design life). In 2005, worldwide installed wind capacity was passing 40 GW with an annual growth rate of about 15%. Furthermore, offshore installations are growing exponentially, especially in Europe, with an installed capacity currently approaching about 1 GW. Because installation costs are much higher for offshore structures, even larger rotors are favored for economic reasons. Clearly there is a question as to what the limits are with respect to current materials systems and what the future materials challenges are, if indeed the sizes have to be pushed even further. This section will explore current turbine structural materials, their properties, and the limits to which they can be pushed for large, high-power wind turbine applications.

3.2.1 Overview of Gearbox and Generator Failure Mechanisms

The gearbox and generator together make up both the most costly and the least reliable system in wind turbines. German insurers require on-line monitoring of these systems or else a complete overhaul after five years or 40,000 hours of service, whichever comes first. The issues with the cost and reliability of the gearbox have led to the development of many research turbines and one family of production turbines (Enercon) that does not use a gearbox, but instead drives the generator directly from the rotor. This approach also reduces the number of bearings in the wind machine to two low-speed bearings, at the cost of a large, multipole generator (84 poles in the 4.8-m diameter generator in the E-40) and sophisticated power electronics.

The most important issue in the reliability of the drive train is wear of the gear teeth and bearings. The causes of this wear include the following:

- Particulates in the oil due to contamination during assembly, corrosion, and wear
- Variations in rotor speed due to imbalance, variations in wind speed, etc., which may cause the gear teeth to chatter, causing fretting and generating particles
- Stress concentrations in gear teeth, due to wear or machining

- Mechanical interference or other manufacturing problems such as heat treatments or surface finish out of specification
- Loss of oil or oil circulation

The symptoms of these problems are changes in the vibration signatures of the gears and bearings, and changes in the size, number, and total mass of particulates generated in the gearbox oil.

For generators in wind turbines, approximately 40% of the failures were related to bearings, 38% were related to the stator, and 10% to the rotor. The stator and rotor problems included phase imbalances and turn-to-turn short circuits. These problems are easily detected and diagnosed by monitoring the stator and rotor currents or, alternatively, by identifying the generation of harmonics in the output power signal. Some other problems with the generator cause a loss of efficiency that can be detected by monitoring the power characteristic.

One study addressed failures of the transmission housing on a certain series of wind turbines. These failures appeared as cracks that allowed the oil to drain from the gearbox, causing shutdown of the turbines. The faults were determined to be caused by fatigue in the housing, and revisions to the manufacturing technique (grinding and shot-peening critical locations) extended the predicted fatigue life to the point that further monitoring was not required.

3.2.2 Gear Failures

Tables 3-2 and 3-3 list common failure modes for gears and bearings, respectively.

Table 3-2
Gear failure modes common to wind turbines

Tooth Cracking	May result from poor gear steel cleanliness (inclusions), improper tooth hardening, or overload during operation. Severe spalling and debris from other failed components can contribute to tooth stresses and lead to tooth breakage.
Micro-pitting	Very fine pits that develop over the contact area of the teeth; may not be visible to the naked eye at the start. The cause is not always clear, but improper tooth grinding and poor lubricant cleanliness are likely candidates.
Abrasion	Can result from poor tooth profile control or a manufacturing error, exacerbated by poor or dirty lubricant.
Spalling	Aside from tooth breakage, Hertzian fatigue is the eventual failure mode for gear teeth. Poor or dirty lubrication, over-rolling of debris or contaminant in the mesh, and localized stress due to misalignment will accelerate spalling fatigue.

Micropitting and some cases of macropitting have been observed on gears for many years. Both of these result in surface pits of differing scale that reduce the effective load-carrying area for contact stress. This increases the local contact stress, thereby exacerbating the problem, and as a consequence, both can reduce the life of the parts affected.

Micropitting is a surface fatigue phenomenon that manifests itself as extremely fine pitting on the gear surface. It has been identified as a function of load, gear design, tooth finish, and lubricant. It is not a purely a material-specific phenomenon. One of the problems is that there is not a good, well-accepted rating method for micropitting risk/resistance. Super finishes (mechanical and chemical polishing, etc.) and super materials (for example, Caterpillar claims that they have custom steels that can handle 5 times higher Hertzian or contact stress than current commercial steels) have been shown to reduce the risk of micropitting, but so has proper gear design and correct selection of lubricants.

Macropitting and sub-case fatigue can be materials problems that are a result of improper heat treatment. Alternatively, macropitting can be from a manufacturing problem where the final grinding of a gear can compromise the hardened region of the sub-surface (for example, by grinding down through it).

3.2.3 Bearing Failures

Each wind turbine model may use gearboxes and generators from several manufacturers. There are six major gearbox manufacturers, and at least as many generator manufacturers. Although components from different suppliers are designed and built to the same interface and performance specifications, they are not identical. There are some commonalities between the failures seen in the various manufacturers' gearbox or generator designs, but in many cases, the failure modes are different from design to design, even for the same size component. Despite extensive research and development efforts directed toward drive train component failures, the root cause for some failure modes has not been defined or at least not publicly revealed.

Table 3-3
Bearing failure modes common to wind turbines

Ring or roller cracking	May result from poor gear steel cleanliness (inclusions) or overload during operation. Severe spalling and debris from other failed components will eventually lead to cracking. Can also result from improper fits on shafts or in housings or from excessive misalignment or force at assembly.
Wear	Generally caused by abrasive contaminant in lubricant, but inadequate lubricant film can promote wear at sliding surfaces (for example, between rollers and cages).
Spalling	Hertzian fatigue is the eventual failure mode for rolling contacts. Poor or dirty lubrication, over-rolling of debris or contaminant in the mesh, and localized stress due to misalignment will accelerate spalling fatigue.
Brinelling	Indentations in the raceways can occur from overload during assembly or transport, especially cyclic loading that occurs with components that are not rotating. Fluting ridges and troughs can occur along the roller-raceway contact length when electrical current passes through the bearing; common with poorly grounded generator rotors.

3.2.3.1 Bearing Materials

Large bearings have shown an increase in failures due to materials. Some of this is due to nonmetallic inclusions in the materials used to fabricate bearing races or rings. Also, some problems have been documented with heat treatment consistency throughout large rings. The observed problem from this is sub-case fatigue due to subsurface stresses due to variations in the hardened case depth (see the discussion below on gear material cleanliness).

Smearing or scuffing has also been observed in bearings. This is a surface wear phenomenon that occurs commonly within a few hours of operation during the run-in or initial beneficial wear of conformal surfaces. This can be a materials problem, but it is frequently the result of one of the following:

- Selecting larger bearings than required
- Using inappropriate bearing configurations
- A lack of appreciation for the system dynamics

3.2.3.2 Gear and Bearing Material Cleanliness

There are some field experiences with gear tooth bending failures due to non-metallic inclusions in the steel. As gears have gotten bigger for wind turbine applications and stress levels have increased (due to competitive pressures to reduce cost and improved gear tooth mesh modeling tools), the cleanliness of the original gear steel has become critical.

For high-performance industrial applications such as wind turbines, AGMA 2001-C95 grade 2 quality is normally specified. ISO 6336 – 5:2003 has an equivalent grade called MQ, which was, more or less, initially based on AGMA grade 2. When ISO 6336 Part 5 was translated into DIN 3990 Part 5, several very important requirements such as steel cleanliness were weakened, and many European gear manufacturers use the DIN and not the ISO standard.

Part of the reason that this shows up with larger parts may be due to the difficulty of applying more sophisticated re-melt techniques such as electrostatic re-melt (ESR) and vacuum arc re-melt (VAR) for parts as large as current wind turbine generator (WTG) gear elements. Application of such high-quality techniques (used widely in aerospace applications) on large parts requires extremely expensive retooling at foundries in Europe that are struggling to stay competitive with foundries in emerging economies.

This is a bit of a concern because some manufacturers have started eliminating planet bearing outer rings by fabricating the ring directly as the inner diameter of the planet gear. The hardness surface requirements can vary greatly between bearing rings and gears, so poor cleanliness could be especially critical at these locations.

3.2.4 Gearbox Bolt Failures

Bolts have sheared inside gearboxes. Though not only a recent phenomenon, its frequency of occurrence has not abated in the past few years. The cause is partially due to materials. But the reasons have been that the bolts supplied and used were improperly labeled "high-strength bolts." This practice has been identified before, but it is difficult to control. This is because bolts are sold as bulk items with quality grades stamped on them at the factory, and little or no paper trail exists to identify the source steel, heat treatment, and processing steps. Standards restrict the use of such bolts inside gearboxes. For instance, ISO/IEC 81400-4:2005 requires that all internal fasteners be metric grade 8.8 or better, but that grade 12.9 or better should not be used under dynamic loading. It further requires that high-strength hardware be source controlled and sample tested to identify mislabeled batches. This is more a quality control problem than a materials problem.

In some other cases, the bolts were of the correct quality but the shrink disk assembly that they were included in was undersized. Apparently, the shrink disk was loaded beyond its yield point, which loosened the clamp, and the resulting dynamic loads damaged the bolts. Standards demand that internal bolts be avoided, but if they are used, they should be wired securely as in aircraft applications.

3.2.5 Blades – Failures in the Field

Blade failures due to materials have not been observed in the field. Experience suggests that the strength is not limited by material properties. Instead, in this limited population (45 failures in a population exceeding 600 blades—type and size unspecified), the observed failures were due to design and manufacturing details.

These failures observed were due to improper lightning protection (easily identified by burned areas), insufficient stiffness (evidenced by tower strikes, etc), and manufacturing issues. The manufacturing issues are, of course, difficult to separate from those that are purely material specific.

Manufacturing problems may include the following:

- Improper curing (for example, final curing make take place in the field and result in unwanted twisting or distortion of the airfoil)
- Difficulties with joints and material transitions (for example, steel root attachment, skin to spar bonding, etc.)
- Ply drops or laminate discontinuities contributing to stress concentrations

3.2.6 Generator Failures

The purpose of this subsection is to present the results of research done by EPRI regarding the nature and types of generator failures throughout the power industry. The degree to which these failures may be relevant to generators installed in wind turbines should be studied further by wind farm owner/operators. Table 3-4 provides a collection of the reported failure mechanisms for various generator subcomponents.

Table 3-4
Generator failure mechanisms

Subcomponent	Failure Mechanisms
Cell slot liners	Migration, liner degradation
Winding copper	Copper dusting. copper distortion, copper foreshortening, moving conductors, spreading of top conductors, end strap elongation
Links and connections	Cracks in damper links, cracks in pole-to-pole connections, main lead fatigue and cracking, coil-to-coil jumpers distorted and partially broken, pole-to-pole jumper distortion
Retaining rings	Arcing damage to the retaining ring, retaining-ring stress-corrosion cracking, retaining-ring pitting, retaining-ring material removal from multiple inspections, retaining-ring seating cracks, top tooth cracking

Table 3-4 (continued)
Generator failure mechanisms

Subcomponent	Failure Mechanisms
Collectors and brushes	Collector flashover, carbon brush dust accumulation, collector ring footprint, and other surface problems
Winding insulation	Shorted field windings, partially shorted turns at speed, insulation deterioration, crushing of insulation, field grounds, rotor temperature monitoring loss of calibration
Contamination	Construction and manufacture debris, metal contamination
End-winding blocking	Missing blocking, loosened blocking, moved out of position
Rotor cooling	Poor design thermally, insulation blocking gas ducts, slot liners shifted or migrated and blocking cooling passages, general overheating
Forging symmetry issues	Asymmetrical stiffness of rotor forging, rotor forging issues
Rotor shaft	Cracked shafts, keyway cracking, stub shaft alignment
Rotor slot teeth	Dovetail cracking, galling of the slot dovetails during wedge installation
Rotor baffle assembly	Baffle assembly damage
Slot liners	Slot cells end cracking, slot liner cracks, slot liner migration
Rotor fan	Blade diffuser damage
Slot wedges	Packing clearance excessive, rotor slot wedge cracks

Table 3-5 shows the type and number of problems reported by the 118 power plant units that provided information to the EPRI research effort.

Table 3-5
Relative frequencies of generator failure mechanisms

Reported Failure Mechanism/Problem	Count
Shorted field turns	20
Retaining-ring stress-corrosion concerns	15
Liner issues	9
Movement of winding copper	8
Distortion of winding copper	6
Main lead cracking	6
Dovetail galling and cracking	6
Contamination issues	3
Radial stud issues	3
Tooth top cracking issue	3
Hydrogen seal problems	3
Bearing grounds	2
Brush rigging grounds	2
End turn blocks loose and missing	2
Forging concerns	2
Retaining ring arcing	2
Shaft cracking	2
Slot wedge cracking	2
Cooling problems	1
Fan cracking issues	1
Low IR reading	1
Generator motoring event	1
Winding connection cracking	1

3.3 Resulting Availability of Wind Turbines

There are a number of different ways to define and track availability for individual wind turbines and wind power plants. To ensure consistency throughout the industry, the turbine verification program (TVP) definition of availability takes into account all downtime experienced by the individual wind turbines in a generating site or wind farm facility and divides the available hours by the total hours in the period. For example, in a 100-hour period, a turbine may be shut down for 5 hours because a site tour is in progress, 5 hours to repair a component under warranty, and 5 hours due to a line outage. The TVP would count 15 hours of downtime in the 100-hour period and report an availability of 85%. This is a conservative approach, which generally results in greater stated downtime compared to other methods.

Key Technical Point
EPRI worked with the DOE and several EPRI members to help establish methods of tracking wind turbine performance:

1. Fort Davis; in Fort Davis, Texas, owned by American Electric Power (AEP)
2. Springview; Keya Paha County, Nebraska, owned by Nebraska Public Power District (NPPD)
3. Searsburg; Searsburg, Vermont, owned by Green Mountain Power (GMP)
4. Glenmore; Glenmore, Wisconsin, owned by Wisconsin Public Service (WPS)
5. Algona; Algona Municipal Utilities in Algona, Iowa
6. Kotzebue; Kotzebue, Alaska, owned by Kotzebue Electric Association, Inc.

The TVP availability method satisfies the needs of a utility that is interested in the total project downtime when the project is unable to produce power, regardless of the cause. Turbine vendors and operators are more interested in an availability definition that includes only turbine reliability downtime for which they are responsible. The vendors and operators have no responsibility or control over the downtime hours resulting from a utility line being down or *force majeure* events. As a result, the TVP definition of availability is not necessarily a measure of turbine reliability.

In general, the TVP availability is lower during the summer months, in part due to retrofit work and scheduled maintenance. At the Fort Davis project, aileron failures, inspections, and repairs have caused significant amounts of downtime since the project began operation. Enron no longer offers turbine models with ailerons, primarily due to the experience gained through this project. Response time to faults affected availability at Glenmore, and rotor lightning damage was a major cause of downtime at Springview. The next subsection provides a more detailed description of the downtime causes at each project.

Although downtime and availability are commonly used as performance measures in the wind energy industry, it is important to understand the time of occurrence and the cause of the downtime along with the actual number of downtime hours. Obviously, 10 hours of downtime during a low-wind period is less significant than 10 hours of downtime during a high-wind period because of the lost opportunity to produce energy during the higher-wind period. As discussed in the next section, the two highest wind-speed months at Fort Davis were April and May, and they had the lowest project availability, resulting in relatively greater lost energy. Also, the year's highest wind-speed month at Springview was May, which was one of the lowest project availability months, while the lowest-availability month, July, also had the lowest mean wind.

The cause of downtime and the cost to return a turbine to service are also important considerations. For example, 10 hours of downtime due to a fault that is reset without additional action has less impact on the project than 10 hours of downtime due to a repair that requires significant labor, equipment, and parts replacement, assuming that the winds are comparable during both periods. The downtime categories include the following:

- **O&M** – All troubleshooting, inspections, adjustments, retrofits, and repairs performed on the turbines and the downtime that accumulates while waiting for parts, instructions, or outside services not available on site but required to place a turbine back online. Downtime associated with the SCADA system is not included in this category if the turbine continues to operate. O&M downtime accounted for nearly 51% of the total 1999 downtime at the six projects, ranging from 17% at Glenmore to 63% at Fort Davis.
- **Faults** – Turbine faults that required a reset with no further action. If a maintenance activity immediately followed a fault, the downtime associated with the fault was combined with the repair hours, and the event was included in the O&M category. In some cases, faults are not cleared until personnel or parts are available or until after a repair is made. In these instances, the fault time was also reclassified as an O&M event if sufficient information was available to make that determination. When faults occur in the evening or on weekends, they are often reset in the morning of the next business day. The response time before the fault was reset is included in the fault category as long as the fault was not followed by repair work requiring tower climbing or other maintenance. High wind and certain cable twist "soft" faults are not counted as downtime because they are considered a normal part of turbine operation and are reset automatically. Faults accounted for 19% of the total downtime at the six projects during 1999, ranging from less than 2% at Kotzebue to more than 63% at Glenmore.
- **Line outages** – Time when the entire project was offline due to a utility line outage at the site. Although no line outages occurred at Glenmore and Springview, line outages accounted for nearly 7% of the downtime at Fort Davis and 5% of the total 1999 downtime for all six projects.
- **Other** – Routine maintenance, inspections, miscellaneous troubleshooting, site tours, and time associated with repairing and removing additional instrumentation and data acquisition systems to support testing activities. Although more than 7% of the downtime for Kotzebue's Phase 1 turbines was attributed to these activities, most of the TVP projects had little or no downtime in this category, which accounts for less than 1% of the total 1999 downtime at the six projects. Kotzebue's "other" downtime was due in part to the construction activities on the Phase 2 and 3 turbines, which caused some project-wide shutdowns.
- **Unknown** – Periods when no documentation related to downtime is available due to missing data or the periods were prior to SCADA installation. The cause is unknown for 12% of the total 1999 downtime at the six projects, ranging from 1% at Searsburg to 20% at Springview. Analysis of the downtime associated with O&M activities and faults is discussed below.

3.3.1 Downtime Due to O&M Activities

Unscheduled maintenance involves responding to any unexpected event, ranging from minor activities, such as resetting sensors or circuit breakers, to major repairs, such as removing a nacelle from a tower to replace the yaw gear. These activities can involve any level of effort from two operators working for less than an hour to a large crew using a crane for a full day or more.

The majority of O&M downtime occurs in April and May. In general, the frequency of O&M events was high relative to their durations at most TVP sites. In other words, the downtime tended to be associated with events that did not require significant time to repair or troubleshoot. Some general observations are provided below:

- Rotor-related – Aileron components on the Z-40A turbines at Fort Davis continued to fail during 1999 in spite of a major retrofit to replace aileron hinges, bolts, and bell cranks during 1998. Bolt replacements and push tube repairs continued throughout the year. All turbines at Fort Davis were taken offline in late April 1999 after ailerons were thrown from two turbines due to the failure of blade-side inboard hinge bolts. Tip brakes on the AOC 15/50 turbines at Kotzebue also required considerable troubleshooting and accounted for 32% of the 1999 O&M downtime for the Phase 1 turbines. Blade damage from lightning strikes accounted for 24% of O&M downtime at Springview. While very little rotor-related downtime occurred at Searsburg, Glenmore, and Algona during 1999, rotor-related retrofit and repair work accounted for 68% of the O&M downtime at Fort Davis and nearly 54% of all O&M downtime at the six projects during the year.
- Controller – Control system events included troubleshooting and replacing damaged components, software upgrades, and modifications to control settings. Firing boards, silicon controller rectifiers (SCRs), and SCR cables required the most attention. Lightning damage to controller components contributed significant downtime to several of the TVP projects, although a retrofit developed with assistance from TVP has improved the lightning resistance of the controllers. Controller downtime accounts for 20% of all 1999 O&M downtime at the six projects, ranging from less than 0.1% at Glenmore to more than 45% at Searsburg.
- Hydraulic system – All projects except Kotzebue experienced some downtime for repairs and troubleshooting on hydraulic systems. Hydraulic system repairs and parts delays account for more than 58% of the 1999 O&M downtime at Glenmore, but only 7% of the total.

3.3.2 O&M Downtime for All Six Projects

The following discussion summarizes O&M downtime for all six of the projects included in the EPRI report *Wind Turbine Verification Project Experience* (1000961):

- **Generator** – Four generators failed at TVP projects during 1999, at Searsburg in March and December, at Algona in September, and at Fort Davis in October. No generator downtime occurred at Kotzebue or Glenmore during 1999. Generator repairs account for 9% and 7% of O&M downtime at Searsburg and Fort Davis, respectively, and averaged nearly 6% of all 1999 O&M downtime at the six projects.
- **Scheduled maintenance** – Scheduled maintenance consists of several basic tasks and includes inspecting the condition of components (for example, checking the wear on brake pads); servicing items that require some type of activity on a regular basis (for example, retorquing bolts); and replacing consumable items at or before a specified age (for example, replacing filters or changing the oil in the gearbox). All of the projects received routine inspections during the year, ranging from less than 2 hours per turbine at Fort Davis and Kotzebue to more than 38 hours per turbine at Glenmore. Scheduled maintenance activities account for more than 16% of Glenmore's 1999 O&M downtime, but only 2% of the total 1999 O&M downtime for all six projects.
- **Other** – The remaining downtime consists of miscellaneous hub bearing, blade pitch, tower cleaning, and brake repair events on various turbines. Occasionally, neighboring turbines are taken offline for safety reasons during O&M work to use components for troubleshooting activities. This category accounted for 7% of the total 1999 O&M downtime for the six projects.

Additional information on the types and timeframe of O&M downtime experienced at each project is included in TVP Program annual operational reports.

3.3.3 Downtime Due to Faults

Faults accounted for more than 19% of the total downtime at the six TVP projects during 1999. As previously noted, the faults in this category are only those "nuisance" faults for which the site operator takes no action other than to reset the turbines. The act of resetting a turbine takes only a small fraction of an hour; therefore, most of the hours in this category represent the time it took the operator to become aware of the fault condition and respond with a reset action.

The most common faults related to the hydraulic, generator, and electrical systems generally increase in frequency during periods of high winds and often occur at the same time, usually as over-line voltage and generator over-current, or over-line voltage and generator over-speed. Yaw system faults such as rotation errors occur during sudden wind direction changes when the turbine rotor begins to spin backward because the winds are blowing from behind the turbine due to gusty and turbulent conditions. On average, each turbine faulted approximately

3.6 times per month and was down for an average of 4.0 hours for each fault during 1999. Although Searsburg experienced nearly three times the number of faults, its average fault duration was half the average duration at the other sites, indicating exemplary response time.

3.3.4 Lightning Impacts and Mitigation Activities

As part of their technical support to the host utilities and turbine vendors, the TVP staff and consultants have engaged in a variety of lightning-related research activities. The need for this work became apparent following the installation and initial experience at the Fort Davis project where lightning caused repeated damage to turbine components during storms. The research has proven to be vital in improving the wind industry's understanding of lightning protection for wind turbines. At the time of the first TVP installations, there was limited experience in the United States with wind turbine operation in high-lightning areas, and wind industry experts had conflicting opinions about "good practices" for lightning protection measures and grounding designs, particularly within reasonable cost constraints.

Section 4: Preventive Maintenance Basis

4.1 General Guidance

The following sections provide an overview of the various types of maintenance activities that can be performed on a wind turbine and its system components.

4.1.1 Preventive Maintenance

Preventive maintenance (PM) tasks are performed based on a time or interval basis to avoid catastrophic equipment failure. PM performs maintenance tasks on a planned rather than reactive basis and avoids the losses associated with unplanned downtime. The penalty of PM is that some tasks are performed that are unnecessary and costly. The following subcategories of PM are based on scheduling of the actions:

- **Grace period preventive maintenance** – Any PM task that is to be performed beyond its original due date but prior to the late date for that activity. Normally, this time period (due date to late date) is an additional 25% of the original schedule interval for the PM task. No engineering evaluation is required. The grace period is provided as reasonable flexibility to allow for alignment with surveillance activities and functional equipment group bundling and to better manage the use of station resources.
- **Deferred preventive maintenance** – A PM task that exceeds its original late date with an approved engineering evaluation that determines the acceptability for the extension to a new due date, before the original late date is exceeded.
- **Delinquent (overdue) preventive maintenance** – A PM task that exceeds its late date (grace period) without an approved extension or deferral.

The distinction between predictive maintenance and periodic maintenance is presented below.

Key Technical Point
Predictive maintenance tasks are performed based on equipment condition. Predictive maintenance relies on technologies to determine the current condition of the equipment so that only the required maintenance is performed before equipment failure.

4.1.1.1 Predictive Maintenance

Examples of predictive maintenance are the following:

- Vibration analysis for all rotating equipment
- Thermography for temperature surveys on electrical equipment, leak detection, overheating, etc.
- Oil analysis (tribology) to determine the equipment condition and also the lubricant condition
- Electrical testing for motor and generators

Key Technical Point
Periodic maintenance consists of "time-based" preventive maintenance actions taken to maintain a piece of equipment within design operating conditions and to extend its life.

4.1.1.2 Periodic Maintenance

Periodic maintenance may be performed to prevent breakdown and can involve servicing such as lubrication, filter changes, cleaning, testing, adjustments, calibrations, and inspections. Periodic maintenance can also be initiated because of the results of predictive maintenance, vendor recommendation, or experience. Examples of periodic maintenance are the following:

- Scheduled valve repacking because of anticipated leakage based on previous experience
- Replacement of bearings or pump realignment as indicated from vibration analysis and/or lubrication oil analysis
- Major or minor overhauls based on experience factors or vendor recommendations
- Instrument calibrations use to meet plant specifications that are not part of a routine surveillance

Key Technical Point
Corrective maintenance tasks are generated as a result of equipment failure. Corrective tasks are generated when equipment is purposely operated to failure and also when equipment failure is not wanted or planned. It is the most basic form of maintenance and also the most expensive. Most plants are moving away from corrective maintenance, but there will always be a portion of maintenance that is performed as a result of equipment failure.

4.1.2 Corrective Maintenance

As a rule, if the specific component requiring maintenance is substantially degraded (for example, packing or bearing degradation) or failed, the action required to repair it is classified as corrective maintenance.

To be considered corrective maintenance, the component must have failed such that it cannot meet its intended functions, or for degradation identified during PM, the component will reach this state before the next scheduled PM interval. There may be cases where corrective maintenance could include standing PM orders/procedures specifically invoked to correct anticipated component degradation. If the degradation does not meet these criteria, it should be considered elective maintenance.

A component should be considered failed or significantly degraded if the deficiency is similar to any of the following examples:

- It is removed from service because of actual or incipient failure.
- It is significant component degradation that affects system operability. The component may be determined operable by engineering assessment, but the degradation is significant and requires immediate corrective action.
- It creates the potential for rapidly increasing component degradation.
- It releases fluids that create significant exposure or contamination concerns. Minor leaks that can be controlled and managed by simple drip catch containments would not be included here.
- It adversely affects controls or process indications that directly or indirectly impair the operator's ability to operate the plant or that reduce redundancy of important equipment.
- Significant component degradation is identified from conducting predictive, periodic, or preventive maintenance, which, if not resolved, could result in equipment failure or significant additional damage prior to its next scheduled PM period.

Detailed guidance regarding the repair of system components is provided in Section 5 of this report.

4.2 Wind Turbine System PM Overview

4.2.1 Introduction

Preventive maintenance aims to increase the reliability and extend the lifetime of generators by providing appropriate servicing at the right time. It consists of annual system inspections and component replacements based on a generator-specific maintenance schedule. The formation of defects in wind turbine generators is normally a long process, so systematic PM can prevent unplanned shutdowns.

4.2.1.1 Comprehensive Maintenance

PM includes the labor and parts needed to perform on-site work as specified by the maintenance schedule:

- Visual inspection of the generator and its operating environment
- Inspection of the connections
- Checking of the generator mounting bolts and alignment
- Inspection, testing, and cleaning of the stator and rotor
- Condition monitoring of the bearings and lubrication
- Cleaning and checking the bearing shield insulation
- Inspection and cleaning of the slip ring assembly

- Cleaning of the cooling system
- Inspection and/or testing of the accessories
- Inventory of the generator spare parts

Once the maintenance work has been completed and the inspection data fully analyzed, a detailed service report should be provided. This includes recommendations for service actions, for spare parts, and for special tools for future actions.

4.2.1.2 Preparations for PM

The effectiveness of the PM work depends on the quality of the information provided by the system owner in service reports. In general, PM is more effective when the information provided is as comprehensive as possible. If the information available is not sufficient, it is recommended that a site survey be performed on the generator before the PM is carried out. During the shutdown, maintenance providers should have free access to the generator for maintenance purposes as agreed. PM must be planned well in advance in order to ensure that the required resources and service parts are available.

4.2.1.3 Maintenance Schedule

Experience indicates that generators become more likely to fail after a number of years in operation. The failing interval depends on the component and how punctually and duly the commissioning and scheduled maintenance have been done. Another determining factor is the life expectancy of the individual component. The main reason is aging of the components, but operating conditions also play a major role. Failure of a component may cause damage to other parts of the machine, including the stator and rotor.

The maintenance schedules should be based on extensive know-how, and they should provide an effective and systematic way to maintain a specific type of generator. The maintenance schedules should generally comply with any specifications issued by the component suppliers. Environmental and operating conditions should also be taken into account. Tough conditions—such as high ambient temperatures, high vibration levels, high operating altitude, humidity, dirt, or heavy loads—can significantly shorten component lifetime and reduce maintenance and component replacement intervals. In order to ensure optimum performance over the entire lifetime of a generator, most manufacturers typically recommend that annual inspections are carried out in addition to regular maintenance.

The following table is an example of proposed preventive maintenance activities for wind turbine generators recommended by a leading manufacturer.

Table 4-1
Turbine proposed PM activities

Inspection	I	Replacement or reconditioning	R
Performance of the Site Work	P	Cleaning	C

Recommended Maintenance Intervals	1/2 year	1 year	3-5 years	Overhaul
1. General construction	I, P	I, P	I, P	I, P
2. Low voltage connection	I	I, P	I, P	I, P
3. Stator & Stator windings	I	I, P	I, P, C	I, P, C
4. Rotor & Rotor windings	I	I, P	I, P, C	I, P, C
5. Slip ring assembly, control & protection	I, P, C	I, P, C, R	I, P, C, R	I, P, C, R
6. Bearings	I, P	I, P, C	I, P, C, R	I, P, C, R
7. Cooling system	I	I, C	I, P, C, R	I, C

Please note that the given recommendations are suggestions only.
Tailor made application may differ from the recommendations.

4.3 Gearboxes

4.3.1 Condition Monitoring of Gearbox Assemblies

Key Technical Point
Typically, after the initial warranty period is over, sound wave attenuation testing (vibration monitoring) and borescopic inspections should be considered to detect abnormal or accelerated wear of gearbox components.

Gearbox instrumentation may be furnished by the manufacturer to accommodate condition monitoring of certain performance parameters in the field. The following performance parameters may be monitored by plant personnel in accordance with the guidance discussed in this section:

- Temperature
- Oil pressure
- Noise and/or vibration
- Oil flow

Additionally, the condition monitoring of the lubricant furnished with the gearbox is critical to ensuring design performance.

4.3.1.1 Temperature Measurement

Temperature is an important indicator of the operation of any gear system. The actual point of measurement is determined by what performance characteristic the user is interested in monitoring.

On a splash-lubricated unit, housing temperature is a common area of concern for troublefree operation. In a pressure-lubricated system, inlet and outlet oil temperatures will give a good indication of both the lubrication system and gearbox health. In critical and high-speed applications, the ability to determine the actual operating temperatures of the individual bearings, in addition to the previously discussed monitoring, is beneficial in determining changes in component health and potential future failures.

- **Thermometers** – These are the simplest of all gearbox temperature monitoring devices. They are generally used to report oil temperature in the gearbox supply or drain lines. Thermometers are slow to respond to changes and require visual examination and human input to evaluate the operational health of the gearbox.
- **Temperature switches** – These are mechanical switches that open and close as temperatures reach predetermined set points. These devices can be used to automatically activate alarms or shutdowns when equipment exceeds predetermined acceptance levels.
- **Thermocouples** – These simple and rugged instruments are highly reliable and produce a voltage output, which requires additional equipment to read. This signal can be used to read actual temperature at remote locations and activate alarms or shutdowns when equipment exceeds predetermined acceptance levels. A thermocouple consists of two dissimilar metals that produce a known voltage as the temperature varies. There are seven metal combinations used in the gear industry; therefore, the type of thermocouple should be known to determine the temperature. Table 4-2 lists these metal combinations.

Table 4-2
Types of thermocouples
(Used with permission from Philadelphia Gear Corporation)

Thermocouple Type	Metal Combinations
T (most common)	Copper – Constantan
J	Iron – Constantan
E	Chromel – Constantan
K	Chromel – Alumel
B	Rhodium – Platinum (30%)
R	Rhodium – Platinum (13%)
S	Rhodium – Platinum (10%)

The most common problems encountered with thermocouples are using a different metal combination than those with which the reading equipment was set and using extension wires that are not the same metal combinations as the thermocouple to which they are connected.

- **Resistance temperature detectors (RTDs)** – These are devices that contain an electric circuit formed of solid conductors (usually a wire). The most common conductors are platinum, iron, and copper. The resistance varies with temperature, and this resistance change can be used to determine the temperature at the tip of the sensor. This signal can be used to activate alarms or shutdowns when equipment exceeds predetermined acceptance levels. RTDs are not as rugged as thermocouples, and care must be taken to ensure that the conductor is not damaged in operation due to handling or vibration. RTDs can be installed in the oil flow path to measure oil temperature, or they can be installed in fluid film bearings to read bearing babbitt temperature.
- **Infrared thermography** – Infrared thermography has gained favor in recent years in helping troubleshoot problem areas where high temperatures are present. The "thermal picture" typically gives indications of where excessive temperature is a problem.

4.3.1.2 Oil Pressure Measurement

Pressure is one of the most important indicators of the effectiveness of a pressure-lubricated system's capability to meet its design function. Pressure is typically measured on a gearbox with either a pressure gauge or pressure switch:

- **Pressure gauges** – Pressure gauges are visual devices that display the pressure at a particular monitoring point. They are usually used to observe oil pressure in the gearbox lubrication system. Pressure gauges require both visual examination and human input to evaluate the operational health of the lubricant supply system.
- **Pressure switches** – Pressure switches are mechanical devices that open and close as pressure reaches predetermined setpoints. These devices can be used to automatically activate alarms or shutdowns when equipment exceeds predetermined acceptance levels.

4.3.1.3 Noise/Vibration Measurement

Vibration measurement is an indication of the condition of the mechanical components of the gearbox. It is extremely useful in evaluating fitness for service for both new units and in predicting potential operating problems for installed equipment. Every mechanical system has a vibration signature. A change in a vibration signature over time is a useful preventive maintenance indicator; therefore, both the current signature and historical signature are often required to properly diagnose a problem.

The key vibration characteristics, which are useful in evaluating a gearbox's health, are the frequency of vibration and the magnitude of vibration. Magnitude is expressed as either movement (displacement), speed (velocity), or rate of acceleration. Examples of typically used devices are:

- **Proximity probes** – Proximity probes are electrical devices that sense the distance a metal body is from the tip of the probe. This type of displacement measurement device is used to determine the movement of a shaft within the bearings and housing. To accomplish this, two probes are needed per shaft at 90° apart. Proximity probes are best used for detecting balance, instability, and misalignment problems and require a probe driver and accompanying readout. They are also particularly useful for lower-frequency vibrations such as shaft rotation frequencies.
- **Velocity pickups** – Velocity pickups are transducers that detect the velocity (speed) of a surface (usually a gear case) to which it is attached. *Vibration* is the physical movement of an object during operation. The movement is usually so small that it is not obvious with the naked eye, but a velocity pickup can detect the actual speed of the surface movement. Because it is often difficult to determine the optimum location for placement of the transducer, the velocity should be measured in all three directions (horizontal, vertical, and axial) in order to ensure that complete and accurate data are obtained. Velocity pickups are also capable of identifying moderately high frequencies such as higher-frequency structural resonance and lower tooth-passing frequencies.
- **Accelerometers** – Accelerometers are similar to velocity transducers, except that in accelerometers the transducers output the acceleration of the monitored surface (usually the gear case), as opposed to the velocity. They are also similar in that it is often difficult to determine the optimum location for placement of the accelerometer. And, as is the case with velocity transducers, care should be taken to measure acceleration in all three directions in order to ensure that complete and accurate data are obtained. This equipment is capable of identifying high frequencies such as tooth-passing frequencies.
- **Noise measurement** – Abnormal noise can result from excessive vibration of the gearbox assembly or its internal subassemblies. Detecting the following types of abnormal sounds may be helpful in identifying problems prior to major failures of the gearbox components:
  - Roughness – possibly indicating poor meshing of the gear teeth
  - Grinding of gear teeth – possibly indicating a gear tooth failure
  - Clashing – possibly indicating misalignment or poor meshing of the gear teeth
  - Whining – possibly indicating partial seizure, high friction, or a partial loss of lubricant

4.3.1.4 Oil Flow Measurement

Flow measurement is used to verify and monitor gearbox lubrication system operation. Gearbox lubrication systems depend on proper oil flow and distribution to perform their function. During gearbox testing, flow is measured to ensure that the oil being supplied to the drive is in agreement with the design requirements. After gear drive installation, a flow monitor should be used to identify changes in the lubrication system performance. The changes can be due to anything from a pump failing to a clogged filter or oil supply line. Examples of the most commonly used instrumentation are;

- **Visual flow monitors** – Visual flow monitors are the most basic of flow-measuring devices. The most common of these devices is a simple sight window with a paddle or a flow indicator with a dial gauge. Both devices indicate the presence or absence of oil flow. Visual flow monitors can be used on the supply-side or return-side oil lines. However, these devices are usually of very low accuracy, and their response varies greatly with temperature and operating conditions. Some of these monitors have a switch that allows remote notification of an abnormal occurrence.
- **Flow sensors (flow meters)** – Flow sensors and transducers are available in a wide range of sizes and accuracies. These devices generate an electric signal that is proportional to the flow passing through the device. These devices are usually not supplied with commercial equipment, but they are widely used in laboratories and testing facilities. These devices are significantly more expensive than the visual flow monitors usually supplied with gearboxes.

4.3.2 Preventive Maintenance Activities

A complete preventive maintenance program for a gearbox should include the elements shown in Figure 4-1. The figure illustrates how a combination of visual inspections, condition monitoring, regular lubricant analysis, and lubricant change contribute to ensuring optimum performance of the equipment.

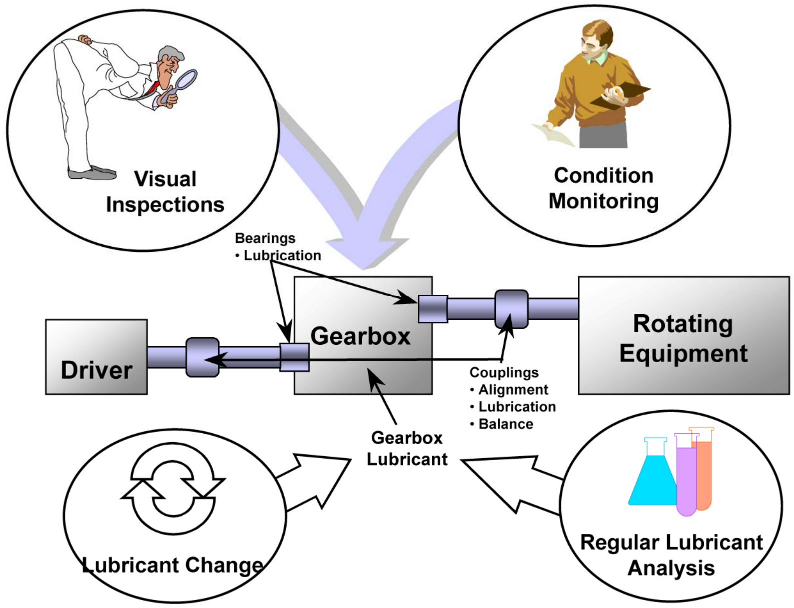

Figure 4-1
Elements of a preventive maintenance program for gearboxes [6]

Key Technical Point
The most important facet of a preventive maintenance program for a gearbox is the regular inspecting, analyzing, and changing of the lubricant.

Section 5 of this report discusses several maintenance activities that require gearbox disassembly and that would be performed in most cases to address a known failure or degraded gearbox performance.

4.3.2.1 Maintenance of Gearbox Lubrication Systems

Key Technical Point
Gearbox oil should typically be sampled every six months. Filters should be changed every year. Gearbox oil should be changed every two years, but some wind turbine manufacturers recommend changing the oil on a three-year cycle.

Table 4-3 illustrates that maintenance activities regarding the lubrication system are performed at various intervals, some of which are on a daily basis.

Table 4-3
Preventive maintenance schedule overview
(Used with permission from Lufkin, Inc.)

Frequency	PM Activities
Daily	Check oil temperature.
	Check oil pressure.
	Check for vibration.
	Check for excessive noise.
	Check for oil leaks.
Monthly	Check operation of auxiliary equipment.
	Check operation of alarms.
	Check for oil contamination.
Quarterly	Analyze oil sample.

Table 4-3 (continued)
Preventive maintenance schedule overview
(Used with permission from Lufkin, Inc.)

Frequency	PM Activities
Annually	Check bearing clearance and end play.
	Check tooth contact pattern.
	Visually inspect couplings and check alignment.
	Inspect tags and labels showing replacement part numbers.
	Inspect safety warning signs and caution labels.

General information on lubrication is as follows;

- **Initial lubricant change period** – The initial startup and operating oil of a new gear drive should be thoroughly drained after a period of 500 operating hours or four weeks, whichever occurs first. The importance of a thorough gear case cleaning with flushing oil to remove particle matter during the first lubricant change cannot be overemphasized. Consult the manufacturer if this is intended to be a fill-for-life application.
- **Subsequent lubricant change interval** – Under normal operating conditions, the lubricant should be changed every 2500 operating hours or six months, whichever occurs first. Extending the change period may be acceptable based on the type of lubricant, amount of lubricant, system down time, or environmental consideration of the used lubricant. This can be done by proper implementation of a comprehensive monitoring program. Such a program may include examining for any of the following parameters:
    - Lubricant viscosity – A rapid change in viscosity may be caused because gear oil is "sheared" as it lubricates the meshing gear teeth. This shearing eventually causes the oil to thin out and lose its film thickness. A rapid decrease could mean oxidation. A decrease of 10% is excessive.
    - Lubricant oxidation, (for example, total acid number) – Check if the total acid number increases by 2. For example: new oil might have a total acid number of 0.4. When this number increases to 2.4 or above, the oil should be changed. This acid number increase is associated with oxidation of the oil, which results in oil breakdown.
    - Water concentration – Water concentration should not exceed 0.1%. Water in oil causes the oil to lose its film strength and also will cause corrosion to gear elements and bearings.
    - Contaminants concentration – Contaminant concentration limits are typically established based on plant-specific operating experience. For example, based on the experience at one site, the oil was considered dirty if the silicon content is above 50 ppm. Similarly, contaminant concentration of iron content above 200 ppm was considered unacceptable.

- Percentage sediment and sludge
- Additive depletion
- Change in appearance and odor

Key Technical Point
Trending contaminant concentrations is important because it provides an indication of significant increases over time. In some cases, an increase of only 10 ppm of iron is significant because iron contamination indicates contamination from gear wear particles.

An alternative method of establishing change-out periods that is gaining acceptance is to change oil only when change is needed based on tests. This means reliance on "leading" indicators of change, such as additive depletion and contaminant concentration. When "following" indicators, such as viscosity and oxidation, are used, and significant change is observed, it is already too late to save the oil.

New lubricant specifications should be used to establish a baseline for comparison. Follow unit manufacturer's and lubricant supplier's recommendations for appropriate subsequent testing intervals. General recommendations and actions concerning lubrication systems are the following:

- **Cleaning and flushing** – When the gear drive reaches normal operating temperature, the lubricant should be drained immediately after shutdown. The drive should be cleaned with a flushing oil. Flushing oil must be clean and compatible with the operating oil. Oils specially blended for flushing, or clean operating oil is commonly used for flushing.
  - Cleaning with solvents – The use of a solvent should be avoided unless the gear drive contains deposits of oxidized or contaminated lubricant that cannot be removed with a flushing oil. When persistent deposits necessitate the use of a solvent, a flushing oil should then be used to remove all traces of solvent from the system. CAUTION: When solvents are used, consult the unit manufacturer to ensure compatibility with paint, seals, sealant, and other components.
  - Used lubricants – Used lubricant and flushing oils should be completely removed from the system to avoid contaminating the new charge and properly disposed of. CAUTION: Care must be exercised not to mix lubricants with different additive chemistry.
- **Protective coatings** – For gearing that may be subjected to extended shipment or storage periods, consideration should be given to applying a protective coating that is formulated to prevent rusting. These coatings must be compatible with the lubricant to be used in service and all other components. CAUTION: Some lubricants may foam due to reaction with rust preventives. If necessary, flush residues from the unit.
- **Filtration** – Gear drives with pressurized oil systems should have a filter on the pressure side of the system to remove contamination particles. As a guideline, in the absence of specific manufacturer's recommendations, the filter should be no coarser than 50 µm (microns) absolute for gear drives with ball or roller bearings and 25 mm absolute for gear drives with journal bearings. In addition, a screen can be used on the suction side to protect the pump. This should be in combination with a filter and must have a coarse mesh to avoid flow restriction. CAUTION: Lubricants should not be filtered through fuller's earth or other types of filters that could remove the additives of the original formulation.

- **Gear tooth wear** – There are numerous modes of damage associated with gear teeth. Proper selection, application, and maintenance of lubricants are, therefore, essential to avoiding premature wear. If premature wear occurs, lubricant selection should be reviewed. As a guide, if rapid increases of any of the following materials are detected, the probable origins of that material are listed below:
  - Alloy steel – Gear teeth, bearings
  - Mild steel – Oil pump, slinger, or baffle rubbing gear case
  - Cast iron – Oil pump
  - Aluminum – Oil seal, seal guards, or carriers
  - Babbitt – Journal bearings

4.3.2.2 Preventive Maintenance for Gearbox Couplings

In many cases, the coupling gets neglected during corrective maintenance activities on the adjoining machines. Once the coupling and all its parts are removed, its component parts may be placed in appropriate packaging (bag or box), and set in a corner somewhere until the machines are reassembled. It may then be taken out of temporary storage, possibly cleaned without much observation to the condition, and reinstalled.

To ensure optimum performance and reliability, the coupling should be checked thoroughly during maintenance activities. Placing a worn or damaged coupling back in service leaves one open not only for operational problems, but also machine problems and the potential for catastrophic damage or personal injury.

Comprehensive guidance regarding preventive maintenance activities for flexible shaft couplings is provided in EPRI report *Flexible Shaft Couplings Maintenance Guide* (1007910).

4.3.2.3 Protecting Gearboxes from Moisture

In some cases, gearboxes might operate in a humid, moist environment. The following common sense approach can effectively protect gearbox internals from excessive moisture and subsequent corrosion:

- Educate maintenance staff to avoid direct jetting of water at ingression points, such as shaft seals, breathers, and others.
- If water spray is inevitable, use passive shields and deflectors to avoid direct water spray on shafts, dipsticks, fill-caps, breathers, and others.
- Use high-performance seals that suffer less wear and offer better protection against contaminants.
- Regularly inspect and maintain gaskets on fill-caps, hatches, and so on.

- Replace dipsticks with level indicators.
- Keep hatches closed tight.
- Replace a basic vent breather with a desiccant breather, which dehydrates incoming air, or an expansion chamber, which allows the system to breathe without ingesting external air.

4.4 Generator

Predictive and preventive maintenance provides the means to ascertain a rotor's material condition and affords an opportunity to take prompt early action, if needed, to forestall major rotor and field problems. Obviously, properly maintaining the generator rotor will extend the service life of the generator and minimize power degradation and outages. An improperly maintained rotor could be subject to minor flaws that will worsen over time if neglected.

Although tests, inspections, and periodic maintenance cannot guarantee extended rotor and field life, they do provide assurance of continued generator operation for the next operational cycle. Some even say that a reliable estimation of remaining life is not possible; however, the predictive and preventive tests, inspections, and tasks are essential for preventing major—or even catastrophic—failures from developing. Analyzing and assessing information from past inspections and tests, operating events and data, industry experience with similar units, recommendations from the OEM, and any current inspections and tests are critical for ensuring the reliability of the generator rotor during the next operational cycle. For further detailed information on rotor maintenance, review EPRI report *Optimized Maintenance of Generator Rotor* (1004951).

4.4.1 Offline Electrical and Tests

Field winding problems include shorts, grounds, and bad connections. Most winding problems can be detected by periodic electrical testing, although some conditions may require that some severity develops before they can be detected. For example, a shorted winding turn might not be detected because the short is often a high-resistance connection that might not significantly change the total measured winding resistance. Additionally, most electrical testing has the limitation that it can be performed only during an outage. Consequently, degradations that occur during operation cannot be detected and assessed by electrical testing until an outage. Complicating matters more is that some grounds and shorts can occur only at speed. Centrifugal forces and thermal expansion may cause a fault that clears when the generator is shut down and cooled.

However, this observation is not intended to indicate that electrical testing is not beneficial. The relatively low cost of the testing versus the high cost of the problems of which it can forewarn, provides a high benefit-to-cost ratio. While continuing to perform periodic generator electrical testing, plants need to be aware of testing limitations and adopt other technologies to augment the electrical testing. Heat sensitive paint or tags, air-gap flux monitoring, and field-ground detection relays are all methods that can be employed while the generator is running and can provide additional critical information on the condition of the field.

EPRI report, *Tools to Optimize Maintenance of Generator-Excitation System, Voltage Regulator, and Field Ground Protection* (1004556) provides more detailed information on electrical testing. Consult that report for further information on field testing and maintenance. The following is a brief overview of the common field electrical tests typically performed at each maintenance outage.

4.4.1.1 Insulation Resistance

Insulation resistance (commonly referred to by the trade name *Megger*) consists of applying a fixed dc voltage between the field winding and rotor forging. The applied voltage produces a small current through the winding's ground insulation that is proportional to the insulation resistance by Ohm’s Law. Typically, insulation resistance meters are scaled to read resistance instead of current. IEEE Standard 43-2000 provides recommendations for testing insulation resistance, including test voltage levels and acceptance criteria.

Low insulation resistance indicates possible insulation trouble. Moisture and contamination are often causes of low insulation resistance. Cleaning the exposed windings along with the rest of the field circuit, such as collector rings if applicable, can help improve the resistance reading. Additionally, for windings where moisture is causing low readings, applying a low heat, blowing dry air, or applying a dc current to the windings should dry the windings and improve the resistance measurement. Any applied current to dry the winding must be limited to well under the winding’s ampere rating.

In addition to problems with moisture and contamination, the insulation resistance test is useful for detecting other problems including insulation degradation, such as abrasion wear and cracking; copper dusting, where applicable; and shifted or displaced insulation.

4.4.1.2 Polarization Index

The polarization index or PI test is often performed in conjunction with the insulation resistance test. A PI test performed by applying the insulation resistance test voltage for 10 minutes and taking insulation resistance measurements at 1 minute and 10 minutes. The PI is equal to the ratio of the 10 minute reading over the 1 minute reading. Unless the leakage current is abnormally large, the PI should be greater than 1. For most windings, the value should be greater than 2. However, in cases where the insulation resistance is very high, more than 5,000 megohms, the PI reading is considered unimportant, and a low PI reading with high insulation resistance is acceptable. IEEE Standard 43-2000 also provides guidance on performing and analyzing PI test results. Changes to insulation resistance and test current over time are illustrated in Figure 4-2.

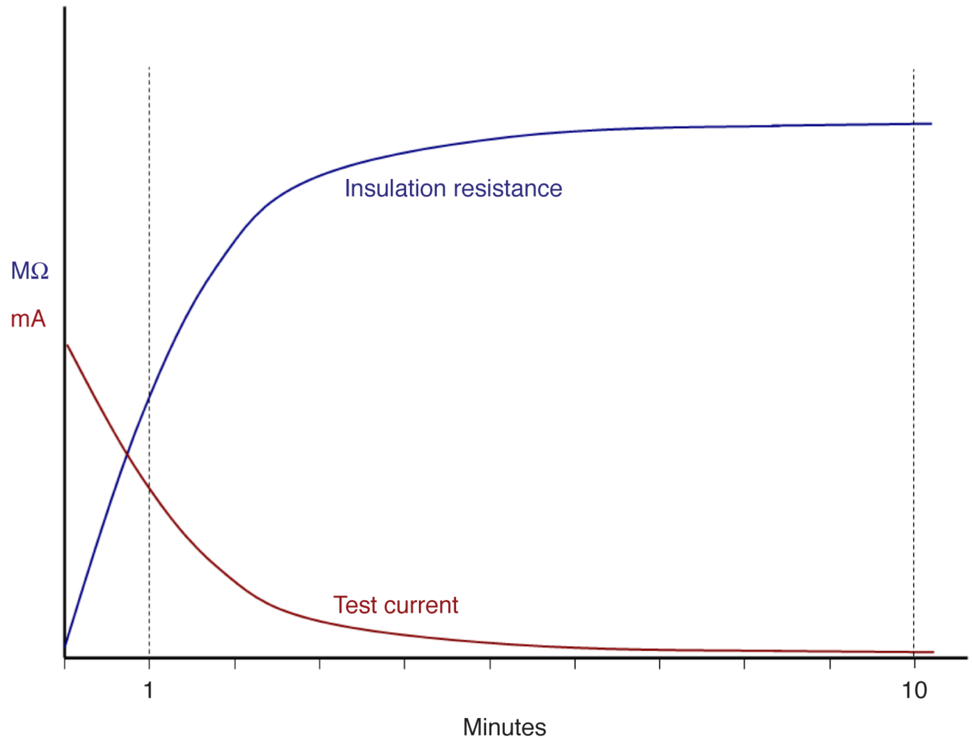

Figure 4-2
Insulation resistance over time

4.4.1.3 Winding Resistance

The total field winding resistance measure from one polarity to the other should stay fairly consistent from one testing cycle to another. Some variation in resistance due to winding temperature will occur and have to be accounted for in analyzing the test results. Standard formulas exist to correlate winding resistance readings to resistance values at a standard temperature. The winding resistance measurement verifies winding continuity, identifies possible bad connections, and possibly detects short turns. IEEE Standard 115 provides recommendations for resistance measurements.

4.4.1.4 Winding Impedance Test

The winding impedance test is typically better than a winding resistance test for detecting shorted turns. With the impedance test, an ac test voltage is applied to the winding in incremental steps. The test voltage is applied in four or five incremental steps, up to a final test voltage of 120–150 volts. The current is measured after it stabilizes at each step. The theory of the test is that at the lower voltage values, current will not flow through a short between turns, as typically the shorts are not solid electrical connections. However, at the higher test voltages, the turn-to-turn voltage can be significant enough to bridge the short.

Once the short is bridged, the turn is effectively removed from the winding, and the winding impedance decreases, allowing more current to flow. Although a plot of the test voltage versus current may not be strictly linear, any abrupt change in the plot, indicating an abrupt impedance change, is an indication of a turn-to-turn short. Figure 4-3 illustrates a simplified impedance test diagram.

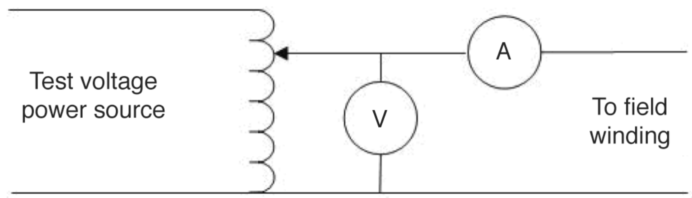

Figure 4-3
Simplified impedance test diagram

4.4.1.5 Recurrent Surge Oscillography

Recurrent surge oscillography (RSO) can be used to identify and locate faults in the field windings. RSO is a variation of the time domain reflectometry (TDR) method to locate faults in cables. The field must be isolated from the rest of the excitation circuit in order to perform an RSO test. The RSO test set is connected to the winding ends, and identical pulses are injected into the field from both ends. If the field winding and its connections are in good condition, the reflections from both pulses should be identical. A ground condition or an interturn short causes a partial pulse reflection from that location that can be detected by the test set. The timing of the reflection indicates how far into the field winding the fault is located.

Special RSO test equipment is required to perform this test, as well as training for the technician who will conduct and interpret the test results. Many plants may not have the equipment or in-house expertise for this test. However, a service shop or a testing company with the equipment and expertise can be brought in during an outage to perform the RSO test, along with other tests and services.

4.4.2 Online Rotor Monitoring

Various online monitoring techniques that provide an indication of rotor condition are available to plants. Some are common in plants and are typically utilized; while others, though beneficial, are not yet regularly employed. Commonly used online methods to monitor rotor and field conditions include:

- Ground detection relays
- Vibration monitoring
- Field temperature monitoring
- Field voltage and current monitoring

4.4.2.1 Field Ground Detection

The field ground detection system is pretty straightforward. The detector, usually a ground detection relay, applies a small voltage between the field circuit and ground and senses the current produced by this voltage. If the ground insulation of the field circuit is good, a negligible amount of leakage current flows. Deterioration of the ground field insulation allows more current. If the current exceeds a certain calibrated value, the detector actuates to alert the plant operators of a possible grounded field circuit. Many generators have a continuous ground detection system wired directly to the field excitation circuit, upstream of the collector rings and brushes. Brushless generators may still employ a brush that is specifically installed to field ground mounting and that is periodically applied to check for field grounds. The ground detection system should be tested and verified periodically through the application of a test ground, typically designed and built into the detection circuit.

Key Technical Point
Generator brushes should typically be replaced every three years.

A detected field ground can have a number of causes including degraded ground wall insulation, copper dusting, and contamination; it may even be due to trouble off the rotor, a ground on the excitation circuit leading the generator. A single ground by itself is not a significant problem in that the generator field is normally an ungrounded circuit. The single ground is not a completed path for the field voltage and, thus, does not produce a fault current. The concern with a field ground is the possibility of a second ground that completes the fault path. Depending on where two or more grounds occur in the field winding, a significant and damaging fault current can flow.

Utilities implement different procedures for response to the detection of a field ground. Some require taking the generator offline as soon as possible. Others require taking the generator offline during the next period of low load within a few days. Still others may permit continued operation for longer periods of time—until a convenient time for an outage is reached. All plants must have a careful risk assessment of their intended actions, balancing the risk of potential generator damage and lost generation against lost revenues and also grid effects from an outage. As has been mentioned previously, the OEM's and experienced service providers' recommendations, as well as that of experienced plant personnel, must be considered in determining the course of action. Additionally, insurers, grid operators, and regulatory entities may have requirements that need to be followed.

Upon receipt of a field ground, plants should verify the presence of the ground and assess the nature of the ground. Typically, the ground detector circuit has a test point at which the detector's ground current can be measured. This test point might be designed into the circuit, or it may have been designated procedurally as a wire to be lifted. Either way, an ammeter measures the ground current, and technicians and engineers can determine the amount of ground current. This provides verification that the ground detector did operate properly and also verifies whether there is a weak or a strong ground present. Additionally, by measuring the voltage at the detector's field wire to ground, it can be ascertained whether the ground is on the positive or negative side of the field. Some detectors may have voltage and current instruments built in to aid in troubleshooting and assessing the ground.

Some visible inspection can be performed with the generator still online to determine if the ground is due to a fault external to the rotor, although personnel safety issues must limit the extent of the inspection. Where applicable and possible, switching off diode banks and other portions of the excitation circuit can be done to try to locate and isolate the ground. EPRI report *Tools to Optimize Maintenance of Generator-Excitation System, Voltage Regulator and Field Ground Protection* (1004556) provides more detailed information on ground location.

4.4.2.2 Field Voltage and Current

The field's voltage and current provides insight into how well the field winding is capable of maintaining generator excitation. Field winding troubles, such as shorted turns and poor electrical connections, will cause changes in either the voltage, the current, or both. Although it is not possible to directly monitor field current on some generators, monitoring the excitation system's output for these machines can indirectly provide similar insight into the field's condition.

Whether field voltage and current are monitored directly or indirectly, these parameters should remain consistent for a given generator output. Other field circuit problems can also impact current and voltage, including brush problems, diode and fuse failure, poor lead termination, and instrumentation errors. However, variation in the current or voltage of a particular generator output still can indicate a problem, whether in the winding or elsewhere in the excitation system.

Field voltage and current monitoring involves periodic review of recorded values for variations that are not due to generator loads or other acceptable influences. The review should also consist of a comparison with past data to detect slowly increasing changes. The periodicity of the review is often once per week, although some plants may choose to use either a shorter or longer period. Based upon their own experiences and needs, plants should decide the scope and frequency of review, but they should also include in the decision process OEM and service provider recommendations and any requirements of insurers and regulatory groups. Additionally, the field voltage and current should be checked once per shift to note any sudden or abrupt variation from normal values.

4.4.2.3 Field Temperature

The field temperature monitoring system typically reads the field voltage and current and computes the field winding temperature. This computation is based upon Ohm's Law to determine electric resistance and the temperature coefficient of resistance for the winding copper in order to provide an average temperature reading of the field winding. On a generator employing collector rings and brushes, the voltage and current transducer are wired directly to the excitation circuit upstream of the brushes. Brushless generators can employ a wireless transmitter mounted on the rotor to relay temperature data.

The field winding temperature should be checked periodically during the shift to note abnormal temperature changes. Often an alarm is used to alert the plant's operator if the temperature rises above a predetermined value. Additionally, the field winding temperature should be trended weekly—or at most monthly—to note gradual variations that can be indicative of problems.

Field problems that the temperature monitoring system can indicate include bad electrical connections, high field current, clogged or blocked cooling passages, fouled cooling heat exchanges, and other cooling system issues. The temperature monitor shows an average field temperature and does not indicate localized heating. Wind turbine personnel should be aware of this limitation as well as the capabilities and usefulness of the monitor. Another method employing heat-sensitive material is useful for identifying localized hot spots and is discussed later in this section.

In addition to showing the average field temperature, the temperature monitor–if it is continually recording the temperature reading—can show certain brush and field circuit problems. Since the temperature monitor is actually sensing voltage and current, any variation in voltage causes a variation in the computed temperature value. The voltage regulator and inductance of the field winding will act to keep a constant field current to maintain generator output. Intermittent connection problems within the field circuit, including the brushes if applicable, will cause voltage to spike, which can show as a spike or a series of spikes on the temperature recording.

4.4.2.4 Vibration Monitoring

Certain rotor and field problems can manifest themselves as rotor vibration. Significant cracking can create asymmetric stiffness of the rotor, causing uneven flexure of the rotor from its weight as it rotates. Shorted turns create uneven current distribution, thus producing uneven rotor heating. This uneven heating in turn causes uneven thermal expansion of the rotor, thereby producing a slight bow in the rotor. Additionally, shorted turns produce uneven magnetic flux in the field winding, which causes a varying force on the spinning rotor.

Generators are typically equipped with vibration monitoring. Significant vibration levels on most generators will cause the monitors to alarm, thereby alerting the operators of high vibration. More severe levels will cause the monitors to trip the generator offline. Below the vibration levels that alarm and trip, vibration signals can exist that indicate possible rotor problems that should be investigated. Routine periodic collection and analysis of the generator's vibration signals are beneficial to detecting rotor and field problems before they become severe.

Vibration data collection for periodic analysis can be performed with installed instrumentation or with probes placed temporarily for data collection. Not all plants have installed vibration instrumentation, and thus have to use temporary probes. Periodicity of the data collection and analysis will vary with equipment condition, plant experience, results from past analysis, and industry experience with similar units. Typically a period of once a month for data collection and analysis is sufficient. Generators which are experiencing problems, or have a history of trouble, may require more frequent monitoring in order to trend the equipment condition and forewarn of severe equipment degradation. Generators in good condition may have a longer period between analyses, but generally no longer than once a quarter.

Torsional Vibration

Increased attention is being paid to the effects of torsional vibration on the rotor. Torsional vibration produces a twisting of the rotor; some experts believe that this twisting may significantly impact the rotor forging, the retaining rings, the rotor shaft, and other components. Back and forth twisting can create metal fatigue over time, possibly leading to cracking and eventually to failure. System transients, such as line switching, heavy loads coming on and going off, nearby power generation, and faulty power system stabilizers, can induce torsional vibration or oscillations in a generator.

For most generators, torsional vibration is rare and does not present a problem. However, plants need to know if their generators may be or have been subjected to torsional vibration. Because of unawareness of the problem in the past and the sophisticated equipment that was required, torsional vibration monitoring was not commonly practiced. A number of plants have installed monitors in recent years as the equipment has become more practical and economic. The installation of a torsional vibration monitor can now often be beneficial, detecting the presence of torsional vibration and providing a measurement of the severity if the vibration exists.

4.4.2.5 Online High-Temperature Detection

Online rotor temperature monitoring systems beyond those systems that use field current and voltage can be quite beneficial in early detection and identification of field hot spots. Formulations with specific chemical compositions can be applied to areas on the rotor and other parts of the generator.

The specific composition of an application is designed to release a signature gas above a certain temperature into the generator's cooling gas. A detector samples the cooling gas and monitors for traces of the signature gases from the various applications in the generator. A key advantage to this system is its ability to detect localized heating of the field. Detecting rotor localized hot spots provides an indication of a winding short or poor connection. A field temperature monitor that relies on the field current and voltage can provide only an average field winding temperature indication.

An example of a signature chemical for detecting field hot spots is dihexyl amic acid in a blue alkyd paint formulation that is applied to the rotor surfaces.

4.4.2.6 Air Gap Monitor

Several of the responses to the surveys used in the preparation of this report recommended the use of online air gap flux monitoring. Air gap flux monitoring has been used in large motors and generators for a number of years; it has proven to be beneficial not only in detecting winding faults, but also in the analysis and assessment of machine problems.

Air gap flux probe installation requires rotor removal and the removal of some stator slot wedges. The flux probes are installed in the stator slot and sense the magnetic field in the air gap between the stator and rotor. Installation obviously requires a generator outage with rotor removal and can increase the outage work scope, especially if stator slot wedge work activities are not planned for the outage. However, the additional work to install the flux probes can be well worth the cost. Detection of small problems during operation, particularly when no other detection means are available, can save expense and time in determining causes of operational issues and problems, such as rotor vibration. Identifying and ascertaining field problems during operation can be an advantage in planning and implementing corrective actions for the next outage.

Usually the air gap flux probes are connected to a monitoring system that allows viewing and analysis of the air gap flux signals. A number of users reported checking and analyzing monitor readings periodically, typically once a week, to ensure no field degradation. If an abnormality is found, the flux monitoring system signals are analyzed to determine the nature and extent of the problem. The frequency of checking and analyzing is increased to determine if the degradation is worsening or if it is stable. Several users reported that due to the success of the installation and use of the air gap flux monitor in one generator, they have installed, or plan to install, the monitor system in other units.

4.4.3 Rotor Inspections

Rotor inspections mainly require removal of the rotor from the generator and can require some disassembly. It can be possible to perform very limited inspections without rotor removal to provide some level of confidence in the rotor's condition. A limited inspection is not recommended for replacing a full inspection, but it may be performed to provide an indication of rotor condition until an outage when the rotor can be removed. The main areas of concern to most are retaining rings, dovetail areas, and end teeth tops. Other areas may be of more concern to some plants with certain generator models. The OEM and experience from other units with similar generators can provide beneficial information on required inspections.

4.4.3.1 Retaining Rings

Several practices regarding inspecting and examining retaining rings were supplied from utilities and service providers. While these practices varied somewhat in frequency and content, there were similarities that show a general set of practices. These practices for examining 18Mn5Cr retaining rings at five-to-ten-year intervals during outages include the following tasks:

- Visual inspection
- Dye penetrant inspections
- Eddy current inspections
- Defect and flaw assessment and analysis

The area around grooves, holes, and other stress concentrators on the retaining rings should receive more attention during inspections because these areas are most likely to produce stress-related cracking and flaws. This is not to say that other areas should be neglected or receive less than adequate attention, as cracking and other flaws may still occur in these other areas. Also, the centering or balance rings used for rotor-mounted retaining rings need a thorough inspection whenever the retaining rings are removed. Particular attention should be paid to the locking key or ring grooves and other high-stress areas on both the retaining ring and centering rings.

Visual Inspection

The retaining rings do not necessarily have to be removed if there is no indication of defects or moisture. However, as always, the OEM guidance and advice from experienced service providers should be heeded with regard to removal and examination of the retaining rings. Visual inspection of the rings should be thoroughly and carefully performed on all accessible surfaces, including borescopic inspection of the interior surfaces if possible. Any deflect, corrosion, signs of moisture, and other flaws must be documented for further evaluation.

Surface coatings, such as varnish, will make visual inspection more difficult and will require a more thorough examination to locate ring problems. Consideration may be given to removal of the surface coating to allow for better inspection of the ring surface, although coating removal should be done only after consultation with the OEM. If the coating is to be removed, it should first be inspected for moisture indications, and obviously, removal and cleaning agents must not contain water.

Moisture indications and new or worsened defects and flaws can be reasons to remove the retaining rings for thorough interior inspections. Even though removing the rings is a costly and time-consuming process; avoiding the risk of a catastrophic generator failure is well worth the effort.

The advice of experienced utility personnel, the OEM, and service providers should be given high value in the determination of whether to remove the rings. With indications of moisture and flaws, it is better to err on the side of safety and remove the rings for further inspection.

Dye Penetrant Inspection

Fluorescent dye penetrant inspection should follow the visual inspection. The dye penetrant inspection can identify cracks, pits, and other defects too small for visual inspection. A fluorescent dye is better for detecting small cracks and pits. Any surface coating, such as varnish, can mask cracks and pits and will need to be removed for the inspection. The precautions regarding coating removal in the previous information on visual inspection should be followed.

Pitting or cracks found in a linear array or in groups require special attention because these may indicate ongoing stress corrosion cracking. All findings from the inspection should be carefully documented and, if possible, photographed. If it is determined that the defects and flaws found are acceptable for continued operation, documentation of the current findings will provide a baseline for future inspections to better ascertain if the flaws are growing or worsening.

During ring interior surface inspections, particular attention should be paid to critical areas. These areas are locations in which moisture can be trapped, such as grooves, and locations containing stress raisers, such as grooves and slots. Additionally, the shrink fit area of the ring is always under stress when mounted on the rotor and should receive special attention.

Eddy Current Inspection

Eddy current inspections should follow the visual and dye penetrant inspections. Flaws undetected by the other inspections may be found by the eddy current inspection. Additionally, the size and depth of cracks and pits found by the visual and dye penetrant inspections may be determined from the eddy current test results. Determining the dimensions of the flaws is invaluable to ascertaining whether continued operation is acceptable, and it also provides baseline data for future inspections. If the flaws are too severe to allow continued operation, determining the size of the flaws provides valuable data for guiding the rework that is required to repair the rings.

For further analysis, if needed and for baseline data, the inspection results should be recorded and stored. The inspection results should be evaluated to determine the nature of any defect and to determine whether the rings are acceptable or whether a repair or replacement is required. Expert personnel, the OEM, and experienced service providers should be consulted to determine ring condition if needed.

Ultrasound Inspection

Some companies reported trying ultrasound testing to further inspect the retaining rings. Ultrasound has the advantage of seeing through the material, potentially sensing defects on both the exterior and interior surfaces, as well as inside the material. Phased-array ultrasound can provide improved capabilities, sweeping through the material at various angles and covering more volume in a shorter time.

Others have reported no success or limited success with ultrasound testing of the retaining rings. Difficulties arise from the coarse grain structure of 18Mn5Cr stainless steel, which can scatter the ultrasound waves, mask potential flaws, and produce inconclusive results. The complex geometry of the retaining rings further complicates the inspection, especially the area around grooves and slots where stress-related flaws may be more probable.

The results of the surveys conducted for this report indicate that present ultrasound technology is not very feasible for examining the 18Mn5Cr retaining rings. This does not rule out ultrasound technology and techniques being developed to better inspect retaining rings; nor does it mean that some plants may not find some benefit in the present technology for inspecting their specific rings.

End Wedge Gap

Faults, load unbalances, switching transients, and other operational occurrences produce negative sequence currents in the generator stator, which, in turn, induces current flow around the circumference of the rotor. These induced currents travel across the surface of rotor forging and take paths through slot wedges and the retaining rings. Current flow between the slot wedges can produce arcing and high heat as the path between the slots and rings is not typically a solid electrical connection.

To prevent current flowing between the wedges and the rings, many generators are designed to have a gap between the slot wedges and the retaining rings. Rotor flexure at low speeds and on turning gear may cause axial movement or shifting of the wedge, closing the wedge gap and retaining ring gap. This shifting and closing of the gap allows for possible wedge-to-ring current flow during negative sequence and motoring events, with arcing and resistive heating.

Not all generators have a designed wedge-to-retaining-ring gap; some rotors are designed to have a good electrical connection by a tight fit between the wedges and the rings. In these rotors, the tight ring-to-wedge connection and the use of aluminum wedges provide for a damper winding on the rotor. In these cases, it is important to maintain the tight electrical connection.

On the generators that require a wedge-to-ring gap, the gap should be checked whenever the rotor is accessible. If necessary, the wedges will have to be shifted away from the ring to restore the gap and locked in position. If needed, the OEM should be consulted regarding methods for locking the wedges in position. If the OEM is not available, an experienced service provider may be able to provide proper methods for securing the wedges.

In-Generator Ring Inspection

Even during outages in which the rotor is not to be removed from the generator, some inspection of the retaining rings may be possible. Borescopes and small cameras operated from the ends of the generator can be use to some measure to determine the condition of the surfaces of the retaining rings. Service providers offering these ring inspections should preferably have references and a proven record of their inspection methods. It is important to note that if the *in situ* ring inspection finds an indication of moisture, arcing, cracks, pitting, and other flaws, the rotor will have to be removed for a more thorough inspection and evaluation.

Outage Precaution

With 18Mn5Cr retaining rings, it is important to prevent contact with moisture not only during operation, but also during outages. Given that retaining rings are heat-shrunk on the rotor, they are still under great stress even when the generator is shut down. Stress corrosion cracking can still occur, regardless of whether the rotor is in or out of the machine, if moisture is present. During periods of generator shutdown, the rotor should be maintained moisture free by the use of dry hydrogen, carbon dioxide, or an inert gas such as argon, which some have begun testing. Tenting the rotor when it is removed from the generator and using heaters or dehumidifiers will greatly aid in minimizing moisture-induced stress corrosion cracking. Even if the retaining rings are made from less susceptible stainless steel, such as 18Mn18Cr, it is still a good practice to maintain dryness of the rotor environment. While 18Mn18Cr stainless steel rings are less susceptible to stress corrosion than 18Mn5Cr, they can still be susceptible to moisture-related problems and should be protected.

4.4.3.2 Rotor Forging

The generator is subjected to various forces and stresses that can contribute to rotor damage. A common type of damage is dovetail cracking, which has been widely believed to be caused by fretting. Dovetail fretting is caused by the movement of wedges in the slot. This is most pronounced with short steel wedges, occurring at the location of the wedge joints. However, some experts believe that all wedges, including aluminum wedges, cause fretting to some degree.

During operation, the wedges are held firmly in place by centrifugal force. It is during startup, shutdown, and turning gear operation that wedge movement can occur. It had been thought that this fretting and low-cycle fatigue (LCF) was responsible for dovetail cracking. Rotors that are subjected to higher amounts of

LCF are more susceptible to dovetail cracking. These rotors include those with a high number of stop and start cycles, such as with two-shifting. A high length-to-diameter ratio, generator motoring events, and negative sequence current occurrences are also significant factors in the initiation of dovetail cracking.

Recently, a number of generator experts, including a major OEM, have performed analyses and studies and have come to believe that dovetail fretting by the slot wedges is not responsible for the initiation of cracking. Their findings indicate that surface currents flowing around the circumference of the rotor are more responsible for crack initiation.

The rotor surface currents, caused by negative sequence currents in the stator or by motoring the generator, can produce heating and arcing on the rotor. The heating and arcing will be more prevalent in areas that concentrate the current and where the current must cross a joint, such as the between the dovetails and the wedges. Pitting and material property changes due to the arcing and heating allow for more metal fatigue from cyclic stresses in the affected areas.

Regardless of the mechanism that initiates dovetail cracking, the cracking can often be repaired by machining if it is discovered in time. A thorough inspection and nondestructive testing of the dovetail areas should be performed whenever the retaining rings and wedges are removed. The OEM recommendations on inspection tests and schedules should be followed to forewarn of possibly significant damage that could require substantial repairs and extended outages.

Significantly advanced cracking might be noticed by high vibration during operation. Typically, complete rotor mechanical failure will not occur as the high vibration forewarns of the cracking problem. However, having vibration monitoring is not a reason to forego rotor inspections. Rotor inspections can prevent excessive repair costs and lengthy outage requirements by providing earlier identification of cracking than is possible by vibration analysis.

Following a generator motoring event or significant negative sequence occurrence, the rotor should be removed and inspected for damage. Although an inspection might not be necessary before returning the generator to service immediately after the event, the significance of the event or occurrence should be determined; and the OEM, or at least an experienced service provider, should be consulted for recommendations.

At the time of this report, a few generator experts believe that inspections for dovetail cracking may be unnecessary unless a motor or negative sequence event has occurred or if the generator has been subjected to prolonged periods of negative sequence currents. However, unless there is verifiable proof that a generator has not been subjected to negative sequence currents, a baseline inspection should be performed to verify that the rotor is in good condition. Furthermore, unless the plant uses a negative sequence current monitor to verify that the generator will not be subject to negative sequence currents, additional periodic inspections will still be necessary.

The OEM recommendations regarding rotor inspections and dovetail cracking should be followed. Recommended time periods may be shortened due to operational events, experiences and findings on similar generators, and advice from in-house and vendor experts. However, the time periods should not be lengthened beyond the OEM's recommendations unless concurrence is given by the OEM.

Rotor Cleanliness

Dirt, oil, and other debris may hide cracks and other flaws on the rotor and in the wedges and other components. The rotor should be visually inspected prior to cleaning to detect abnormalities, such as copper dusting, oil deposit, excessive dirt, signs of overheating, etc. It is important to identify any presence of rust and other evidence of moisture.

After the initial visual inspection, in order to be better able to detect cracks and other flaws and perform NDE inspections, the rotor should be cleaned as much as physically possible. It is important to ensure a clean rotor to provide cooling and electrical insulation of the field and to provide for thorough inspections. If moisture indications such as rust are found, a thorough inspection of the retaining rings should be performed. Particularly for 18Mn5Cr rings, the rings may need to be removed for interior inspection.

Copper dusting, if excessive enough, can lead to field winding grounds and interturn shorts. Electrical winding tests should be conducted, if dusting is found during inspections, to detect the presence of shorts or grounds. Although significant grounds may be detected by the field ground detection relay, an insulation resistance test should be performed to detect weak grounds.

Inspection Methods

As mentioned in the previous information on cleanliness, the rotor surface should be visually inspected prior to cleaning and also prior to removing retaining rings and wedges, if these are to be removed. The inspection should seek to identify any signs of contamination, debris, moisture, overheating, copper dusting, and other problems, as well as cracks, pitting, and other mechanical defects. If problem indications are found, their location and description should be documented for further evaluation. Additionally, photographs will be beneficial for evaluation purposes and as a historical record. If wedges are to be removed, another inspection should be performed as well, because the wedges may have blocked signs of fretting, dusting, and other problems. Additionally, the wedges themselves should be inspected for defects such as cracking.

After cleaning and wedge removal, if applicable, a thorough inspection of the rotor should be performed to identify cracks, fretting, and other mechanical flaws that may have been hidden before the cleaning of the rotor. Special attention should be paid to stress concentrators on the rotors and other components, such as holes for cooling gas flow. The holes and other concentrators may be more prone to developing cracking and other defects. Portable lighting and small hand mirrors will aid in inspecting difficult areas.

Defects identified in the inspections should be documented and photographed for evaluation and for added attention during NDE inspections. The characteristics of the defects need to be noted in the documentation, whether they appear to be due to fretting, cracking, overheating, arcing, etc. The size of the defects is important to note; include the length, width, and, if possible, the depth. The OEM, service provider, or in-house generator expert needs to be made aware of identified defects as soon as possible in case further inspection is required or if corrective action will have to be taken. Certain flaws, if minor, may have been identified and documented in previous outages. This documentation is important to verify whether these flaws have worsened or remained the same. Documentation from inspections in previous outages can be beneficial to the inspectors by identifying known flaws and where added attention may be needed. Some of the NDE inspection methods that can be used are the following:

- Dye penetrant inspection

  The dye penetrant inspection, or penetrant test (PT), can detect cracks or small defects down to approximately 0.060 inches (1.5 mm). The fluorescent dye penetrant provides better visibility, allowing for possible defect detection down to 0.030 inches (0.8 mm). The better visibility from using fluorescent dye is achieved by using a UV light in a darkened environment. Under normal lighting conditions, the use of a fluorescent dye is not advantageous over the use of a nonfluorescent dye. The penetrant test is used mainly when the wedges are removed because the dovetail region of the slots is the main area of concern for fretting and crack initiation.

  In addition to the dovetails, the wedges and other areas of the rotor can and should be inspected with dye penetrant as needed. A detailed rotor inspection is not necessarily a routine task to perform whenever the rotor is removed since this can be very time consuming. However, as a result of OEM guidance, a generator motoring event, or a negative sequence current occurrence, a somewhat-detailed inspection of certain areas on the rotor surface might be prudent. Particular areas that might receive special attention would be around cooling passage holes and other stress risers and also similar areas that might concentrate current flow during a motoring or negative sequence current event.

- Magnetic particle inspection

  The magnetic particle inspection offers similar capability as dye penetrant for detecting surface cracks and flaws and typically can performed in a shorter period of time. This inspection is also referred to as "mag" particle, magnetic particle test, MT, or MPT. Magnetic particle inspections can be performed only on magnetic materials. Nonmagnetic items, such as aluminum wedges, require another inspection technique.

  The same rotor areas and components that can be inspected with dye penetrant can be inspected with magnetic particle, except for the nonmagnetic components. Magnetic particle inspection may be difficult to perform in rotor slots due to space and configuration limitations. To perform dovetail inspections, a special probe may be required to reach inside the rotor slots.

Cleaning is required after performing a magnetic particle inspection. Care must be exercised during application, performance, and clean up to prevent particle material from getting into windings, cooling passages, and other areas. The rotor should be checked for residual magnetism before returning to service.

- Eddy current inspection

Eddy current inspections are more sensitive and faster than dye penetrant and magnetic particle inspections. This inspection is also referred to as eddy current test, ET, or ECT. This technique can be employed on any conductive material; thus, it can be used to inspect aluminum wedges.

The equipment to perform eddy current inspections is more expensive than dye penetrant material and magnetic particle inspection material and equipment. Additionally, a higher skill level is required both to perform the eddy current inspection and to analyze the results. Fretting, arc strikes, and other surface abnormalities may prevent the detection of small cracks beneath them.

Still the eddy current method offers a number of advantages for inspecting the rotor, including higher sensitivity. Also, once initially purchased, the eddy current inspection does not require additional purchases of expendable inspection materials. Because no inspection material is required, no cleanup is needed after the inspection.

- Ultrasound inspection

Ultrasound inspections, like eddy current inspections, require skilled and experienced inspectors and are typically quicker than either the dye penetrant or the magnetic particle methods. The ultrasound method provides the ability to see inside the material being inspected and even may allow inspection of an opposite surface through the material. Thus, there is some capability to allow dovetail inspection without wedge removal.

The complex geometry of a volume under test can make ultrasound ineffective; scattered sound waves and reflections can cause some flaws to go undetected and may produce false indications. Skill and experience are often required to correctly position the probe and scan the material under test, but even then, the shape of the material may prevent accurate readings.

Some have reported success with phased array ultrasound in inspecting rotor dovetail areas from the rotor surface with wedges installed. In phased array, several ultrasound waves of the same frequency are emitted from the test probe with each wave's phase shifted, based upon from where on the probe the wave is emitted. The shifted phasing, which is adjustable, steers the ultrasound beam at a desired angle from the probe. Thus, the probe can be held flat against the rotor surface, while the beam is directed at an angle to a side surface, such as the dovetail area. Additionally, by varying the phase shifting, the beam can be swept through various angles to sweep and inspect a wider area without moving the probe.

To be able to verify that an ultrasound inspection will be able to provide accurate results of the dovetail surface or any other far surface through a material volume, a calibration block should be used. A calibration block is a sample of similar material and with the same geometry as the volume to be inspected. For dovetail inspection, the calibration should be a replica of a short length of a rotor tooth with the same cross-sectional shape and dimensions. The calibration block should have defects created in it at known locations, with the defects made to the actual defect sizes that should be detected by the inspection. To verify the ultrasound inspection procedure, the inspector needs to inspect the calibration exactly as will be done on the rotor. The results should identify all known defects and not produce any false positives.

Rotor Inspection Practices

Based upon information provided by utilities and service providers, the following is an overview of typical dovetail inspections. Not all plants necessarily follow the overview exactly; but many that have provided information to this project have indicated processes similar to the following:

- Perform visual inspection of the rotor and wedges.
- Clean the rotor.
- Perform a second visual inspection after cleaning.
- Perform a magnetic particle inspection if the wedges and winding are removed.
- Perform an eddy current inspection if the wedges are removed, regardless of whether the magnetic particle inspection was performed.
- Use dye penetrant to inspect areas that may not have been adequately inspected by the other techniques or where inconclusive results were obtained.
- Perform ultrasound testing if the wedges are not removed.
- The retaining rings should be inspected with the rotor.
- If the rings are removed, the end teeth will need to be inspected also, with attention given to top tooth cracking on units known to be susceptible to this problem.
- Rotor fans, couplings, the rotor shaft, and other rotor components also should be inspected with the rotor forging inspection.

Items in the above list should not be used if it they contradict OEM recommendations. The OEM recommendations and guidance should be followed. The rotor does not typically need to be inspected during every outage; but it should be done whenever OEM recommendations specify or sooner, based upon past inspection findings, operational history, on-line monitoring, and advice of in-house or vendor generator experts.

If the generator was exposed to significant negative sequence currents or if it was motored by being connected to the power grid without its field being energized, the rotor will need to be inspected for possible damage. Whether the generator should be allowed to return to operation prior to an inspection will depend upon the severity of the event and upon recommendations by the OEM or other experienced generator experts.

Regardless of whether the generator is permitted to return to operation, the rotor will still need to be inspected as soon as practical. Minor damage to the rotor may not have an immediate impact on continued operation for a limited time period, but the damage may worsen over time. Consequently, it needs to be detected and repaired when possible.

Hardness testing may be required in areas where overheating from high current and arcing occurred. High heat may have soft or hardened the rotor steel in these areas. Affected areas may require shot peening to correct the hardness or may require machining to remove the affected material. Rotor machining will require carefully analysis and evaluation to ensure that rotor strength is not adversely affected. The OEM or an experienced service provider will usually need to be brought in to support, if not direct, the project.

Based upon the findings from the inspections, additional inspections may be required. If wedges were not removed and ultrasound inspection identified possible cracks in the dovetail area, the wedges will need to be removed for further inspection of the affected area. Depending on the number and extent of defects identified, all wedges may need to be removed for a complete rotor inspection or possibly only just enough wedges to inspect the slots in the affected area.

Identified defects should be well documented, preferably accompanied with photographs. Include in the documentation the size, location, and depth of the defects and other pertinent data as well. The documentation will serve to provide data for evaluating the condition of the rotor, provide baseline data for future inspections, and if repair is required, will give information needed to properly plan and implement the required work. Required work may include machining the cracks and other defects out of the rotor and also possibly machining portions of the rotor to remove stress risers to prevent future problems. The OEM or an experienced service provider will need to be brought in to direct, or at least support, the project to ensure that the structural integrity of the rotor is not compromised.

Top Tooth

Certain rotor designs with rotor- or body-mounted retaining rings have the potential for top tooth cracking, particularly in older generators. Susceptibility of this problem varies with rotor design. Pressure from the heat-shrunk ring significantly stresses the teeth under the ring, and during operation, centrifugal force reduces these stresses. Cyclic operation of the generator varies the stresses on the teeth, creating metal fatigue. The locking key groove concentrates the stresses and increases the fatigue. On susceptible rotors, when cracking occurs, it typically forms between the groove and tooth end.

The tooth tops under the retaining rings should be inspected and have nondestructive examinations performed whenever the retaining rings are removed. To thoroughly inspect the tooth tops, the end wedges will have to be removed. Inspection of the end teeth is similar to inspection of the rotor teeth for dovetail cracking; involving visual inspection, dye penetrant, eddy current, and ultrasound as needed.

Due to the expense of removing the rings and wedges, plants may want to plan tooth top inspections based upon their own and industry experience with the particular rotor design; however, they should still follow OEM recommendations to the extent practical. Deviations from the OEM recommendation should have OEM concurrence or at least involve consultation with the OEM to ensure that the plant has accurate knowledge of the potential risks involved.

As mentioned previously, areas such as the locking key groove can be stress concentrators and be prone to crack initiation. Inspectors need to pay extra attention to these areas on rotors with body-mounted rings. If cracking is found in the tooth top areas, a repair is frequently possible. Repairs often involve machining out the cracks and other defects. Furthermore, to prevent reoccurrence of this issue, the repair will usually include modifying the shape of the end teeth, the locking groove, and other stress concentrators (see Figure 4-4). The OEM should be consulted on recommended repairs and modifications because they likely have had experience with repairs on other similar generators. The following image shows smooth bends machined into the dovetails of the end teeth to remove the sharp-angled stress risers.

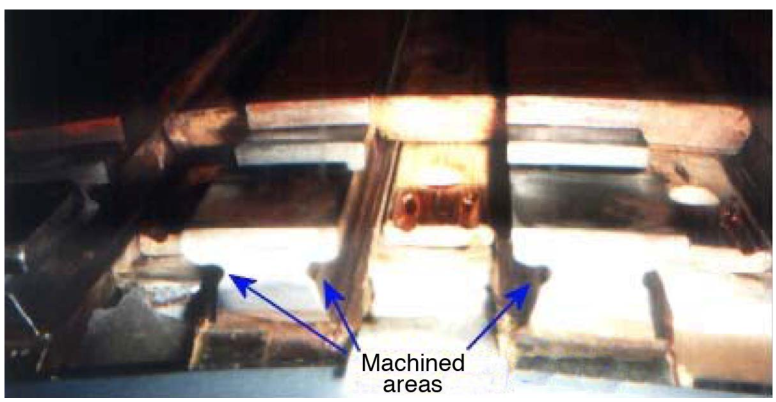

Figure 4-4
Modified end teeth

4.5 Foundation and Outer Area

Table 4-4 provides an overview of typical PM activities that should be considered for the foundation and outer area that are typically performed on a six-month basis.

Table 4-4
Semiannual preventive maintenance activities for the foundation and outer area

Component/ Assembly	PM Activities Performed Semiannually
Outer area	Visually inspect stairs, catwalk, board, and railing for corrosion or physical damage.
Exterior lighting	Perform a 1-hour functional test.
Grouted joints	Visually inspect for physical damage, flaking, and water-tightness.

Table 4-5 provides additional PM activities that should be considered for the foundation and outer area that are typically performed only on an annual basis.

Table 4-5
Annual preventive maintenance activities for the foundation and outer area

Component/ Assembly	PM Activities Performed Annually
Transformer station	Perform a visual inspection of the transformer station in accordance with the manufacturer's recommendation.
Foundation	Visually inspect the base pad for signs of excessive cracks, physical damage, or flaking.

4.6 Control Cabinets in the Tower

Table 4-6 provides an overview of typical PM activities that should be considered for the control cabinets in the tower that are typically performed on a six-month basis.

Table 4-6
Semiannual preventive maintenance activities for the control cabinets

Component/ Assembly	PM Activities Performed Semiannually
Main cabinet	Visually inspect the general condition, the tightness of connections with various components, doors, coatings, and electrical leads. Perform a functional test of controls, doors closing properly, ventilation, and cable clamping. Visually inspect the general condition and cleanliness of the filter element. Set the thermostat at 25°C, and verify operability of temperature control with the filter fan and thermostat returned to service. Ensure that the proper version of the programmable logic controller (PLC) software is installed. Verify that all parameters of the PLC software are properly set. Ensure that the proper version of the turbine process computer (PC) software is installed. Check the parameters of the turbine PC software in accordance with the software provider's recommendations. Perform a disk defragmentation of the turbine PC. Perform a functional test of the uninterruptable power supply (UPS) to ensure that the system remains in operation for at least 5 minutes.
Low-voltage main distribution system	Replace the fan filter as needed. Visually inspect cables and cable terminals for corrosion, insulation, abrasion, spark marks, and physical damage. Visually inspect the contactor relay for tight connection and spark marks. Visually inspect the connection of circuit breaker (synchronization switch), for arc marks, cleanliness, and the condition of the arc chamber and contacts. Perform a functional test of the terminal for tight connection and contact, as well as switching function. Perform circuit breaker maintenance in accordance with the manufacturer's recommendations. Verify that all circuit breaker parameters are properly set. Visually inspect the filter element. Clean and replace it if needed.
Frequency converter cabinets	Visually inspect the insulated gate bipolar transistor (IGBT) power circuits, capacitors, battery, over-voltage protection of dc link, heating, grid protection, fuse gear and tripping units, and insulation resistance. Visually inspect the general condition of the filter element, and replace it if needed.

Table 4-7 provides additional PM activities that should be considered for the control cabinets that are typically performed only on an annual basis.

Table 4-7
Annual preventive maintenance activities for the control cabinets

Component/ Assembly	PM Activities Performed Annually
Low-voltage main distribution system	Visually inspect the circuit breakers for tight connection, spark marks, and cleanliness. Perform a functional test of the circuit breakers to ensure tight connection and contact switching functions. Visually inspect the cable terminals for signs of corrosion and spark marks. Visually inspect the grounding system for physical damage, corrosion, and spark marks. Perform a functional test of the grounding system to ensure tight connection and alignment of the torque stripe mark. Visually inspect the fuse amperage, contacts, and inspect for arc marks.
Frequency converter cabinets	Visually inspect the cabinet for general condition, vibration damage, attachment of bed plates, corrosion, deposits, spark marks, seals, filters, insects, and rodents. Perform a functional test of the ventilation system, fan, doors, sensors, and dissipater. Visually inspect the cables and cable terminal connections, insulation, corrosion, arc marks, abrasion, breaks, discoloration, and penetrations. Perform a functional test of cables and terminal connections to ensure good contact. Visually inspect the temperature/moisture sensor of the low-voltage section control circuit for tightness and moisture. Perform a functional test of the low-voltage control section, and ensure that the doors are closing properly.

4.7 Tower Components

Table 4-8 provides an overview of typical PM activities that should be considered for the tower components that are typically performed on a six-month basis.

Key Technical Point
Initial maintenance of the wind turbine should include retorquing the bolts.

Table 4-8
Semiannual preventive maintenance activities for the tower

Component/ Assembly	PM Activities Performed Semiannually
Door/entrance area	Visually inspect the door for tightness and corrosion. Perform a functional test to ensure that the entrance door closes and locks and that the ventilation grid is functional.
Anchor bolts	Visually inspect for corrosion and paint damage. Verify pre-tension of the bolts. Adjust the tension of the bolts as needed in accordance with the manufacturer's recommendation.
Tower flanges	Verify the torque of the tower flange bolts (typically, 10% every cycle). Visually inspect the flange grounding for corrosion, connection security, and electrical contact.
Tower wall	Visually inspect for corrosion, deposits, cracks, welds, and danger signs. Perform a functional test of the electrical sockets and lamps.
Power supply	Visually inspect the power and control cables for attachment, damage to insulation, integrity of the cable baskets, twisting, and tightness of the compression fittings. Visually inspect to ensure that the cable twist does not exceed three turns in each direction. Perform a functional test of the cable to ensure that the twist corresponds with the yaw direction and degrees or with the analog value of the nacelle revolution. Visually inspect the cable untwisting switch for damage, dirt, and security of attachment. Perform a functional test of the cable untwisting switch for actuation, signal errors, and yaw limit switch actuation. Check the alignment of the automatic untwisting system by comparing the untwisted cable harness with the zero-degree yaw position. Visually inspect the deviation of the zero-degree position of the nacelle with the zero-degree yaw position.

Table 4-9 provides additional PM activities that should be considered for the tower components that are typically performed only on an annual basis.

Table 4-9
Annual preventive maintenance activities for the tower

Component/ Assembly	PM Activities Performed Annually
Platforms and hatches	Visually inspect the attachments and hinges for corrosion and physical damage.
Interior components	Visually inspect the interior components (platform and ladder connections, bolted connections for cable terminal strips, guide tubes, and power cable) for damage, cracks, welds, missing components, and abrasion.
Hoisting passenger suspension device	Visually inspect and test the hoisting passenger suspension device (climb assist) in accordance with the manufacturer's recommendation. Visually inspect the fall protection/ladder for damage, attachment, alignment during ascent, bolted connections, cracks, fractures, and stability. Visually inspect the chain hoist in accordance with the manufacturer's recommendations.

4.8 Nacelle

Table 4-10 provides an overview of typical PM activities that should be considered for the nacelle components that are typically performed on a six-month basis.

Table 4-10
Semiannual preventive maintenance activities for the nacelle

Component/ Assembly	PM Activities Performed Semiannually
General	Visually inspect insulating material for cracks and detached pieces. Visually inspect the nacelle for cracks, tightness, and lighting. Visually inspect the attachment of the nacelle/base frame, rail, weather station, and navigation lights, grounding strip, and ventilation system. Check the tightness of the nacelle enclosure fasteners. Visually inspect the ground cable for corrosion, connection, and electrical contact. Visually inspect the nacelle hinged cover for missing or loose parts and to ensure that it seals properly.
Tread of the steps/grating	Visually inspect the tread of the steps and grating to ensure tight connections and no accumulation of dirt and for corrosion/physical damage.

Table 4-10 (continued)
Semiannual preventive maintenance activities for the nacelle

Component/ Assembly	PM Activities Performed Semiannually
Top box	Visually inspect the contactor sensor to ensure secure electrical continuity, the general condition, and that no arc marks are present. Visually inspect the contactor sensor control elements, keyboard, cable terminals, and electrical connections. Perform a functional test of the contactor sensor control system. Perform a functional test of the rotational speed sensor.
Safety chain	Perform an operational test of the safety chain emergency stop button and system. Perform a functional test of the safety chain vibration switch. Perform a functional test of the safety chain rotor lock switch.
Wind vane and anemometer	Visually inspect the wind vane and anemometer for physical damage, corrosion, sealing, and attachment. Perform a functional test of the anemometer readings. Perform a functional test of the heating system for the wind vane and anemometer. Visually inspect the heating system for the wind vane and anemometer to ensure that the cables are securely attached and positioned correctly.
Navigation lights	Visually inspect the navigation lights for loose or missing parts and secure cable connections. Perform a functional test of the lamps and emergency power supply.
Yaw system	Perform a wear test of the brake pads. Visually inspect the yaw drive for leakage, oil level, cleanliness, and attachment. Empty the yaw drive grease collection container/pan. Check the torque of 10% of the bolted connections of the yaw drive to the base frame. Check the torque of 10% of the bolted connections of the yaw bearing to the top tower flange. Lubricate the yaw bearing in accordance with the manufacturer's recommendations. Visually inspect the yaw bearing for signs of grease leakage and for seal and lubricant line integrity. Visually inspect the cleanliness and attachment of the position sensor. Perform a functional test of the position sensor, and adjust the setting as needed.

Table 4-11 provides additional PM activities that should be considered for the nacelle components that are typically performed only on an annual basis.

Table 4-11
Annual preventive maintenance activities for the nacelle

Component/ Assembly	PM Activities Performed Annually
Base frame	Visually inspect the base frame for cracks, corrosion, and physical damage. Visually inspect the welds of the base frame and generator mount for cracks, corrosion, and physical damage. Check the torque of the bolted connections for the generator mounting frame.
Safety chain	Visually inspect the safety chain over-speed monitor for cleanliness, setting, and proper attachment. Perform a functional test of the safety chain over-speed monitor and signaling device.
Yaw system	Visually inspect the dismantled brake piston for even lubrication and wear. Lubricate the brake piston in accordance with the manufacturer's recommendations. Visually inspect the clear ring and driving pinion for corrosion, wear, and tooth contact pattern. Lubricate the clear ring and driving pinion in accordance with the manufacturer's recommendations.

4.9 Drive Train

The following guidance regarding maintenance of the drive train may be considered to supplement the detailed guidance on gearboxes provided in Section 4.3 of this report and on generators provided in Section 4.4 of this report. Table 4-12 provides an overview of typical PM activities that should be considered for the drive train that are typically performed on a six-month basis.

Table 4-12
Semiannual preventive maintenance activities for the drive train

Component/ Assembly	PM Activities Performed Semiannually
Connection of the rotor/shaft	Visually inspect the connection for signs of wear or corrosion. Check the torque of all bolted connections of the rotor shaft/hub.

Table 4-12 (continued)
Semiannual preventive maintenance activities for the drive train

Component/ Assembly	PM Activities Performed Semiannually
Main bearing	Visually inspect the main bearing for signs of leakage, cracks, and corrosion. Perform a functional test to detect unusual noises emanating from the bearing. Empty the main bearing grease collection container/pan. Lubricate the main bearing in accordance with the manufacturer's recommendations. Perform a visual inspection of the main bearing lightning protection system for cleanliness and brush wear. Replace the lightning protection system brushes if needed.
Gearbox	Visually inspect the gearbox for leakage, oil level, gear-tooth system/roller bearing. Take oil samples in accordance with the manufacturer's recommendation. Visually inspect the gearbox oil cooler for leakage, attachment, and integrity of the oil hoses. Clean the oil cooler chiller and fan assemblies.
Slip-ring unit	Visually inspect the carbon brushes. Lubricate the slip-ring assembly. Replace any broken or blue-brushed brushes. Check the brush alignment. Replace the carbon brushes if needed. Visually inspect the housing seal for signs of wear or physical damage.
Brake system	Visually inspect the brake pads for broken parts or excessive wear. Readjust the brake, and check the adjustments. Replace the brake pads if needed, and reset the air gap. Visually inspect the brake disk for signs of uneven wear, cracks, and freewheeling of the disk and to ensure that the brake pads are parallel to the brake disk. Visually inspect the brake caliper for corrosion or leakage. Check the torque of the bolted connections of the brake gearbox. Visually inspect the wear sensor for signs of physical damage. Perform a functional test of the wear sensor and "pads worn" switching signal. Perform a functional test of the brake positioning system.

Table 4-12 (continued)
Semiannual preventive maintenance activities for the drive train

Component/ Assembly	PM Activities Performed Semiannually
Brake system (continued)	Visually inspect the hydraulic hose lines for damage, embrittlement, deformation, leakage, and fittings. Visually inspect the hydraulic unit for signs of corrosion, leakage, and oil level. Fill with oil if needed. Perform a functional test of the pressure switch and switch timing. Bleed or purge the brakes if needed. Perform a functional test of the pressure relief control valve. Check the pre-charging pressure of the active brake accumulator. Bleed or purge the hydraulic unit if needed.
Coupling	Visually inspect the general condition of the coupling for damage, cracks, defective disks, red rust between the steel disks, and bolt corrosion/loss of coating. Visually inspect the rotor lock of the high-speed shaft for wear and loose or missing parts.
Generator	Visually inspect the generator for coating damage and signs of corrosion on the connecting leads. Visually inspect the bearing for leakage. Perform a functional test of the bearing for signs of excessive noise and vibration. Lubricate the bearing in accordance with the manufacturer's recommendations. Check the torque of the bolted connections of the generator damper. Check the torque of the bolted connections of the terminal box. Visually inspect the generator sound insulation for abrasion, cracks, and corrosion. Check the tightness of the bolted connections of the generator sound insulation system. Visually inspect the length of the power circuit carbon brushes, and replace them if needed. Visually inspect the dust filter, and replace it if needed. Visually inspect the length of the grounding carbon brushes, and replace them if needed. Perform a functional test of the fan and clean air ducts if needed. Visually inspect the fan motor for wear or corrosion, and replace it if needed.

Table 4-13 provides additional PM activities that should be considered for the drive train components that are typically performed only on an annual basis.

Table 4-13
Annual preventive maintenance activities for the drive train

Component/ Assembly	PM Activities Performed Annually
Rotor shaft	Visually inspect the rotor shaft for corrosion and wear.
Shrink disk	Visually inspect the shrink disk for corrosion, wear, and physical damage. Retighten the gearbox shrink disk connection, and grease it in accordance with the manufacturer's recommendations. Retighten a sample of 10% of the shrink disk bolts. If any one bolt can be turned more than 20°, retighten all of the bolts on the flange.
Rotor lock of low-speed shaft	Visually inspect the rotor lock for corrosion, wear, and physical damage. Check the bolted connection of the rotor lock device. Perform a functional test of the rotor locking device.
Rotor lock of high-speed shaft	Visually inspect the rotor lock for corrosion, wear, and physical damage. Check the bolted connection of the rotor lock device. Perform a functional test of the rotor locking device.
Coupling	Check the bolted connections of the coupling flange.
Generator	Replace the incremental encoder every 10 years.

4.10 Hub

Table 4-14 provides an overview of typical PM activities that should be considered for the hub components that are typically performed on a six-month basis.

Key Technical Point
Initial lubing of the blades, yaw bearing, and pitch bearing should be done immediately after construction.

Table 4-14
Semiannual preventive maintenance activities for the hub

Component/ Assembly	PM Activities Performed Semiannually
Nose cone	Visually inspect the nose cone for cracks and corrosion at the connection and along the railing. Visually inspect the steps, sealing, and hinges for cracks, corrosion, and loose or missing bolted connections.
Pitch system	Visually inspect the pitch bearing for integrity of the seals and for leakage of grease at the blade and lubrication lines. Lubricate the pitch bearing in accordance with the manufacturer's recommendation. Visually inspect the pitch drive for signs of corrosion, leakage, oil level, contact pattern of the gear tooth system, and lubricating grease on the gear ring. Check the torque of the bolted connections associated with the pitch drive. Visually inspect the pitch motor to ensure proper wear of the carbon brushes and cleanliness. Replace the carbon brushes if the brush spring is below the specified minimum distance away from the brush holder. Perform a functional test of the pitch motor auxiliary fan. Visually inspect the gear ring and driving pinion for corrosion, gear teeth contact pattern, and cleanliness. Visually inspect the 0° and 90° switching cam, limit switch, and bracket for cleanliness and proper attachment. Perform a functional test of the switching signal, manual stop at 85°, and emergency stop at 89°. Visually inspect the central and axis cabinets for cleanliness and proper attachment. Retighten the bolted connections of the cabinets as needed. Visually inspect the tightness and proper attachment of components, terminal grease, bolts of the battery contacts, and cable clamping. Perform a functional test to ensure that the doors close securely. Visually inspect the condition of the battery cabinet for loose or missing parts, spark marks, or physical damage.

Table 4-14 (continued)
Semiannual preventive maintenance activities for the hub

Component/ Assembly	PM Activities Performed Semiannually
Rotor blades	Visually inspect the outside of the rotor blades for evidence of lightning strikes, cracks, coating damage, corrosion, and cleanliness. Perform a functional test to detect any noise or vibration. Visually inspect the inside of the rotor blades for cracks, secure bolted connections, moisture, corrosion, and cleanliness.

Key Technical Point
Pitch bearing lubrication should typically be performed every six months. Initially, however, many are not lubricated properly, and after six to eight months of use, some damage may occur. The initial procedure for greasing these bearings should be detailed to include the appropriate amount of grease and the type of grease.

Table 4-15 provides additional PM activities that should be considered for the hub components typically performed only on an annual basis.

Table 4-15
Annual preventive maintenance activities for the hub

Component/ Assembly	PM Activities Performed Annually
Pitch system	Retighten a sample of 10% of the bolts between the pitch bearing and the hub. If any one bolt can be turned more than 20°, retighten all of the bolts on the flange.

4.11 Typical Preventive Maintenance Template

The PM template in Table 4-16 summarizes the program of tasks and task intervals for the equipment type. Each plant should base its program on the manufacturers' recommendations and its own history of equipment performance. The PM template can serve as a beginning for development of a PM program for the equipment, and changes can be made as a result of feedback received during implementation of the program.

4.11.1 PM Template Information and Definitions

The PM template contains the following information:

- Conditions. Columns 1 through 8 list the eight sets of conditions for the system components. Each column corresponds to the combined choices of critical or non-critical equipment, high or low duty cycle, and severe or mild service conditions. Time intervals for the performance of each task are entered at the intersections of the task rows and columns 1 through 8.

The definitions of template application conditions are the following:

- Critical

  Yes. Functionally important; that is, risk significant, required for power production, safety-related, or other regulatory requirement.

  No. Functionally not important, but economically important for any of the following reasons: high frequency of resulting corrective maintenance, more expensive to replace or repair than to do preventive maintenance, or high potential to cause the failure of other critical or economically important equipment.

- Duty Cycle

  High. Frequently cycled or partially loaded during the greater part of its operational time.

  Low. Fully loaded during the greater part of its operation time.

- Service Condition

  Severe. High or excessive humidity, excessively high or low temperatures, excessive temperature variations, excessive environmental conditions (such as salt, corrosive, spray, steam, or low-quality suction air), or high vibration.

  Mild. Clean area (not necessarily air conditioned), temperatures within the OEM's specifications, and normal environmental conditions.

▪ PM Tasks. The PM tasks provide a cost-effective way to intercept the causes and mechanisms that lead to degradation and failure. The PM tasks can be used to develop a complete PM program or to improve an existing program. These tasks are intended to complement and not to replace the PM recommendations given by the manufacturer. A brief description of the PM tasks follows the PM template.

Table 4-16
Example PM template for wind turbine system components

Conditions	1	2	3	4	5	6	7	8
Critical: Yes	X	X	X	X				
No					X	X	X	X
Duty Cycle: High	X		X		X		X	
Low		X		X		X		X
Service Condition: Severe	X	X			X	X		
Mild			X	X			X	X
PM Tasks:	Frequency Interval							
Calibration	D	W	W	W	M	M	M	M
Cleaning	D	W	W	W	M	M	M	M
Lubrication	M	Q	Q	Q	S	S	S	S
Oil analysis	M	M	M	M	Q	Q	Q	Q
Operator checks	D	W	W	W	M	M	M	M
Vibration analysis	M	M	M	M	Q	Q	Q	Q
Visual inspection	D	W	W	W	M	M	M	M

D = Daily, W = Weekly, M = Monthly, Q = Quarterly, S = Semiannually, A = Annually

4.11.2 Description of Preventive Maintenance Tasks

The following is a brief description of PM tasks often included in the PM template.

- **Calibration** – Calibration of the wind turbine equipment includes the setting and verification of instruments and components. Instruments include thermocouples, resistance temperature detectors (RTDs), pitot tubes, and pressure gauges. Some examples of calibration are for the scales, the zero load reference should be checked every other day, and the calibration should be checked every week for several months after installation. Simulated load tests, or material tests, and zero load tests should be conducted at periodic intervals between official tests in order to provide reasonable assurance that the device is performing correctly.
- **Cleaning** – The cleaning of equipment and components is very important. The appearance of black dust on all equipment limits the operations and maintenance personnel from seeing the movement, position, or location of many components. The accumulation of dust or grime can clog filters, jam rollers, interfere with limit switch operation, etc.
- **Lubrication** – The addition and changing of lubrication is a very critical function for the wind turbine system components. Airborne dust and dirt can contaminate lubrication and destroy bearings. The frequency of lubrication and changing lubrication varies with the equipment.
- **Oil analysis** – Oil analysis is valuable predictive maintenance technology for detecting problems in equipment before failure occurs. For the wind turbine equipment, oil samples should be taken and analyzed for the gearboxes and any other rotating equipment. Samples should be analyzed for contamination and oil properties. The results of the oil analysis can alert personnel that bearings are failing, and plans can be made to monitor the operation of the equipment, take more frequent samples, or shut the equipment down.
- **Operator checks** – Operator checks (that is, operator rounds) include an external visual inspection of the wind turbine equipment. This includes listening for noises, smelling for smoke, checking temperatures, checking pressures, looking for leaks, checking oil levels, and so on. Section 4.11.3 of this report provides a summary of typical operator rounds performed by one owner/operator of a large wind farm.
- **Vibration analysis** – Monitoring of the wind turbine drive train with vibration sensors and performing vibration data analysis prevents component forced outages. When abnormal vibration is detected, then further investigation is warranted. Detection of failing bearings can allow the component to be repaired before it fails.
- **Visual inspection** – The single most important PM task is visual inspection. The operations or maintenance personnel should be looking for any abnormal activity, missing bolts, failed welds, excessive corrosion, physical deformation, etc.

4.11.3 Example of Operator Rounds at a Wind Turbine Facility

Provided below is an example of the scope of activities that one wind farm owner/operator included as part of their operator rounds. The list of activities is provided for illustrative purposes only and should be considered as a benchmark from which to develop site-specific procedures.

4.11.3.1 Operator Rounds for Transformer Stations

The following activities should be considered for inclusion in operator rounds:

- Check the counter on the transformer load tap changer.
- Rotate the supply of transformer cooler groups.
- Check the operation of the transformer fan.
- Inspect or test the emergency generator.
- Check the condition of the sumps.
- Check the bushings and insulators for contaminants.
- Ensure that the oil spill instruction/inspection sheet is current.
- Check the disconnect, magnetic, and ground poles.
- Inspect the operability of the fire extinguishers.
- Inspect the operability of the eye-wash stations.
- Inspect the general appearance of the station exterior and grounds.
- Verify the operability of the station lighting.
- Check the supply of the following items:
  - Emergency operations kits
  - Indicating lamps
  - Light bulbs
  - Equipment tags
  - Fuses (potential transformer, station service, low-voltage, etc.)
  - Spill kits
  - Portable grounds

4.11.3.2 Operator Rounds for Towers

The following activities should be considered for inclusion in operator rounds:

- Verify the operability of the Federal Aviation Administration (FAA) light control system.
- Inspect the lower tower interior.
- Visually inspect the exterior of the nacelle.
- Verify the performance and documentation of the scheduled PM activities.
- Inspect the operability of the fire extinguishers.
- Review the completeness and accuracy of the log books.
- Visually inspect the lower tower exterior for general appearance and cleanliness.
- Check the supply of the following items:
  - Indicating lamps
  - Light bulbs
  - Tower lighting
  - Ladders

Section 5: Repair and Replacement Guidance

5.1 General Guidance

Figure 5-1 illustrates a generic process for determining whether to repair or replace a system component that is no longer performing in accordance with design requirements.

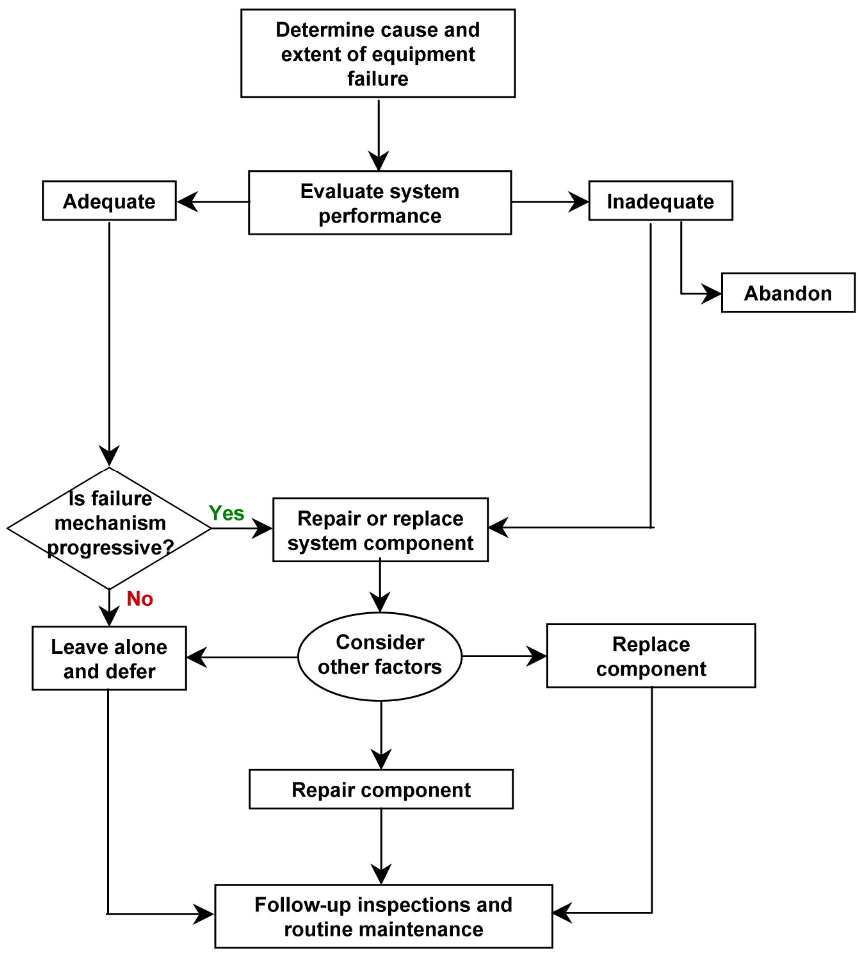

Figure 5-1
Generic repair vs. replace evaluation (Based on EPRI 1009670)

The question of whether to repair, replace, or defer maintenance on a system component is often a complicated one to answer. The issue is further complicated by whether the analysis is performed for an entire system or simply a particular component of an existing wind turbine system. In most cases, a thorough economic cost study is the only effective way to obtain a quantified answer.

Key O&M Cost Point
As a general rule of thumb, if the repair costs are 50% or less of the replacement cost, then repair should be considered. If the percentage is greater, then replacement is generally the best option.

This rule of thumb is generally effective if the system can be put out of service during replacement construction. Of course, one option is to do nothing or defer the maintenance.

Figure 5-2 illustrates a number of factors that should be considered when performing a comprehensive analysis. Some of the factors are easier to quantify than other factors, and in some cases, actual costs can be estimated. To quantify the results of the analysis, some factors may be weighted as to their relative importance in the calculation.

Because of the complexity of the analysis and the varying relevancy of each factor, this report does not attempt to provide a mathematical equation for performing such a calculation. The reader should also note that some of the factors are more qualitative in nature, and they tend to be more difficult to quantify in those cases where an economic cost study is desired.

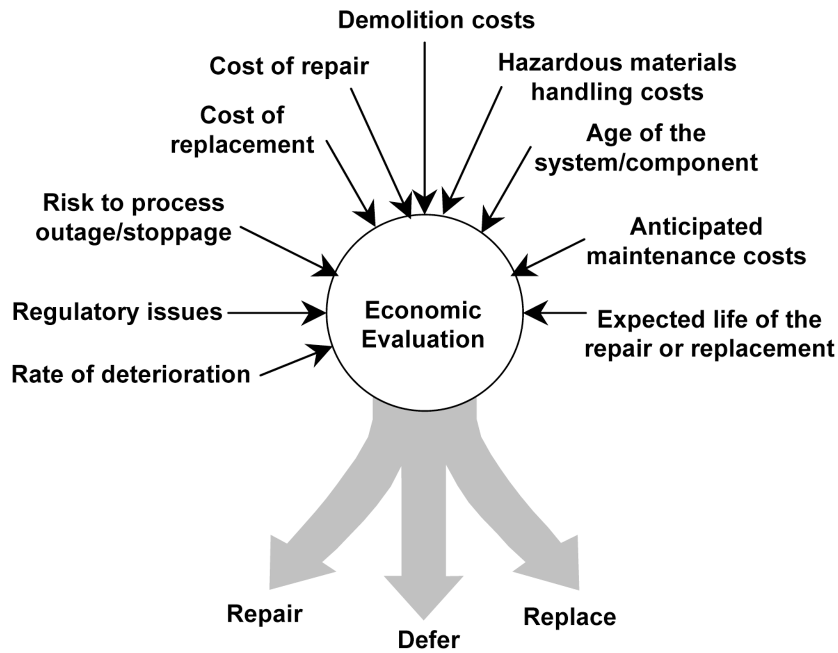

Figure 5-2
Factors considered during the decision-making process (Based on EPRI 1009670)

Each of the factors illustrated in Figure 5-2 is discussed in more detail below. The reader should recognize that this list of factors is not all-inclusive and is provided for illustrative purposes only.

5.1.1 Quantifiable Factors for Economic Cost Study

As noted in the previous information, some factors are easier to quantify than others, and in some cases, costs can be estimated for each course of action. A brief discussion of the quantifiable factors and costs is provided below:

- **Cost of the repair** – One of primary factors that should be considered is the cost of the repair. This cost is typically composed of the costs for materials, equipment, labor, and preparation needed to perform the repair. For the purposes of this report, this cost would not include follow-on maintenance costs associated with maintaining the repaired components over the life of the operating system.
- **Cost of replacement** – Another primary factor that should be considered is the cost of replacement. This may apply to either the entire system or a particular component under evaluation. Similar to estimating the cost of a repair, replacement costs should include the costs for materials, equipment, labor, and preparation needed to replace the existing component(s). Likewise, for the purposes of this report, this cost would not include follow-on maintenance costs associated with maintaining the replaced components over the life of the operating system.
- **Anticipated maintenance costs** – When making the decision to replace or repair a particular component, the manager should consider the anticipated maintenance costs associated with either action. Whether an item is replaced or repaired, there will be costs associated with maintaining it for some period of time. An estimation of projected maintenance costs should include the following components:
  - Maintenance equipment costs – Special equipment and/or tools are often required to perform a repair or to replace a given item. The costs of using these items should be factored into the decision as to whether replace it or repair it.
  - Labor costs – The labor costs associated with projected or anticipated maintenance are important to consider because they may constitute a significant component if the life expectancy of the operating system or component is high. Labor costs can be affected by the availability of maintenance personnel, whether special or unique skills are required, and/or whether the maintenance personnel are in-house or contracted.
- **Demolition costs** – In many cases, there are significant demolition costs associated with a replacement that are not necessarily as important when performing a repair. Demolition costs should include costs associated with preparing the system or structure for the replacement, removal of the components that have been replaced, and disposal of the waste.
- **Hazardous materials handling costs** – In some cases, there are costs associated with handling certain hazardous materials, such as asbestos, lead paint, and hazardous chemicals, that should be factored into the overall cost of performing maintenance and/or repairs on existing operating systems and their components. These costs may be so significant that the most economical option is to defer the maintenance or repair until the end of the service life of the component.

5.1.2 Key Qualitative Factors in the Decision-Making Process

Several key qualitative factors that should be considered in the analysis are discussed in more detail below:

- **Rate of deterioration** – The rate of deterioration is another factor that should be considered when evaluating the cost benefits of either repairing or replacing a system component. The rate of deterioration primarily impacts the urgency with which the item needs to be addressed. For an item failing at a slow rate, the system owner is afforded additional time to decide what course of action to take. In some cases, the rate of deterioration may be so slow that the best course of action is to defer any action until the component's condition becomes more severe. Items failing at a faster rate require that more prompt action be taken.
- **Age of the system/component** – The age of the operating system and its components should be factored into the evaluation for a number of reasons. First, the older the system is, the less likely it is that repairs will be feasible. Conversely, the newer the system, the less likely it is that it would be beneficial to replace the entire system and the more likely it would be to perform repairs of needed components. Secondly, older systems may have a number of maintenance issues that need to be considered simultaneously. The repair costs of these multiple issues should be considered together and not separately.
- **Risk to process outage/stoppage** – The risks associated with inadvertently interrupting the process(es) should be considered from two perspectives—short term and long term. In the short-term perspective, the system owner should consider which action, repair, or replacement would present the least risk to interrupting the processes. In some cases, a repair can be performed without any disruption to the processes; whereas a replacement may require the process equipment to be shut down until the replacement is complete. When this is the case, the system owner may also consider the cost of lost production necessitated by the replacement.
- **Expected life of the replacement or repair** – Other factors that should be considered are the expected life of the replaced or repaired component. Regardless of what action is taken, the restored condition will not last forever. In time, the item will either have to be initially repaired, repeatedly repaired, or replaced again. The length of time until one of these follow-on activities is needed will vary, depending on the maintenance decisions taken now.
- **Regulatory issues** – Regulatory issues that may have arisen or new regulations that may have been enacted since the original construction of the system should also be considered when deciding on the optimum maintenance action to take.

5.2 Repair and Replacement of Wind Turbine Components

Repair and replacement of wind turbine components, such as blades, or components that make up the nacelle, tower, or hub should be coordinated closely with the original wind turbine manufacturer.

Because of the complexity of many of the system components that are integral to a wind turbine system, most are repaired until they have reached the end of their service life. Depending on the extent of the repair and the skill of the craft within the maintenance organization, assistance from an authorized service representative recommended by the original equipment manufacturer may be warranted. Care should be taken if a third-party organization will be performing the repair or replacement.

5.3 Repair and Replacement of Gearboxes

The maintenance activities recommended in this section are generic in nature and may not be applicable, in whole or in part, to all gearboxes installed in power generating facilities. Each user of this report should apply the guidance in this report in conjunction with the equipment-specific guidance provided by each particular gearbox manufacturer when performing gearbox maintenance.

5.3.1 Typical Procedure for Gearbox Disassembly

5.3.1.1 General Guidance

The following disassembly sequence is provided in this report for information purposes only and should not be used without reference to the manufacturer's instructions that are specific to the actual gearbox being maintained. Note that any work done on equipment during the manufacturer's warranty period without the written approval of an authorized manufacturer's representative could void the warranty.

Lock out/tag out procedure – These steps should be followed to complete the lock out/tag out:

1. Identify the energy sources used and all control devices.
2. Notify all affected personnel.
3. Turn OFF all operating controls.
4. Lock out or tag out all switches and energy controls in the OFF or SAFE positions.
5. Test all operating controls to ensure that no power is getting to the equipment.
6. Perform the required maintenance.

Visual inspection – Visual inspection of the gearing through the inspection cover may provide the information necessary to determine the cause of a problem without complete disassembly.

5.3.1.2 Tools Required

For disassembly and reassembly, several commonly available tools may be required. No special tools or fixtures are required for the housing and gears, and often no tools for assembly/disassembly are provided by the manufacturer. Following is a list of some tools that may be useful:

- Crane or hoist, along with soft slings or chains.
- Eyebolts
- Dial indicator
- Pry bar
- Crocus cloth or fine steel wool
- Wrenches, screwdrivers, torque-wrench
- Prussian blue or similar dye for tooth contact check
- LocTite No. 49-31 Plastic Gasket or an equivalent plastic gasket material

5.3.1.3 Spare Parts

Parts such as gaskets should be replaced when a disassembly is performed. The manufacturer should be contacted to obtain a list of recommended spare parts because they vary from one manufacturer to another and from one mode to another.

5.3.1.4 Removal of Gear Cover

Inspections typically performed prior to gear cover removal include the following:

- As-found alignment conditions
- Various end-play checks and verifications

Throughout the disassembly sequence, observe carefully what may have occurred inside the unit, and record the position and condition of any failed parts. Note any parts, bolts, nuts, or holes that are numbered or match marked; they must be reassembled as matched for correct assembly.

1. Remove any deflectors, baffles, or coupling guards.
2. Disconnect the high-speed and low-speed couplings.
3. Disconnect any piping, conduit, or wiring that joins the housing sections.
4. Remove any bearing temperature sensor service heads, probes, or other auxiliary instruments that could be damaged by removal of the cover.
5. Remove the cap screws in the upper half of the seals, end caps, and thrust bearing housing; if lock wiring is supplied, cut it where necessary.
6. Remove the end caps, seals, and gaskets.

7. Carefully loosen the thrust bearing housing. (Use the jacking screw holes to loosen it from the gear housing.)
8. Remove all cap screws and nuts on the parting line. Leave the studs in place to serve as guides for the cover removal.
9. Break the parting line seal by using jacking screws in the jacking screw holes located on each end of the gear unit. Giving some sharp raps with a rawhide hammer at the corner positions and prying with a large screwdriver may be needed to loosen the parting line joint.
10. Attach a crane or hoist to the lifting provisions in the cover, and carefully lift the cover by lifting both ends equally about 1/4 inch (6 mm). Check that the bearings remain seated and that no conduit or wiring that crosses the parting line is still connected.
11. Check the upper low-speed bearing halves to see if they are stuck in the cover. If they are, carefully pry them out, or push them out with a rod inserted through the bearing thermometer holes.
12. Carefully lift the cover straight up until it clears the gearing. The cover will need enough clearance above the gear and studs for the cover to be removed. CAUTION: Do not bump the gear assembly with the raised cover.
13. Place the cover on wood blocks so that the machined split line will not be damaged. Care should be taken to ensure that internal lubrication lines are not damaged.

5.3.1.5 Removal of Pinion, Gear, and Bearings

Removal of gearing from housing is not required if only the rotating element inspection is needed. Radial bearings can be removed and replaced by rolling the shells out of the housing, one bearing at a time (replace the bearing after inspecting it and prior to inspecting other bearings). The thrust bearing is typically more difficult to remove and reinstall than the radial bearings, and detailed guidance is provided below.

Key Technical Point
It is advisable to pour a small amount of oil on each bearing or journal surface to ensure that an oil film is present whenever manually rolling the gear elements because the lubrication system is inoperable.

1. Mark the location of each bearing in the housing so that it can be reassembled correctly.
2. Remove the pinion with the bearings in place, using a soft sling on each side of the mesh. Place the shaft on a soft material, such as wood or rubber or a padded V-rack, taking care not to damage the gear teeth.
3. Remove the upper half of the low-speed bearings.
4. Remove the low-speed gear and shaft assembly with a chain inserted through a lifting hole or eyebolts inserted into the gear. Take care to protect the teeth by placing wood blocks between the chain and the sides of the gear.
5. Place the gear on a soft surface, such as wood, taking care not to damage the teeth. Block each side to prevent the gear from rolling.
6. Gears may be inspected at this time in accordance with the guidance provided in this report.

5.3.1.6 Thrust Bearing Removal

The thrust bearing might contain temperature sensors, and the lead wires exit the bearing housing through the oil fitting. Following is a sequence for removal of the thrust bearing:

1. Remove the temperature sensors from the thrust bearing shoes with a small hooked probe to pull out the star washer through the access cover that is adjacent to the sensor connection heads.
2. Remove the thrust-bearing end-cap bolts.
3. Remove the end cap and shims from the thrust-bearing housing.
4. Use wide-jaw pliers to pull the outer backing ring a short distance out of the thrust-bearing housing.
5. Remove the outer backing ring and thrust pads. Mark the position of pads containing embedded temperature sensors so that they can be returned to their original location.
6. Remove the axial-probe target plate.
7. Loosen the set screws or locking tabs in the thrust-collar lock nut. Note that some thrust collars are integral to the shaft.
8. Remove the lock nut by turning it counterclockwise. Use a spanner wrench or a small punch inserted into the spanner holes to loosen the nut.
9. Insert cap screws into the threaded puller holes in the thrust collar.
10. Carefully remove the thrust collar. Do not allow the collar to drop down and damage the lock nut threads as it is being removed.
11. Mark the position of the inner thrust pads containing embedded temperature sensors so that they can be returned to their original position. Remove the shoes and inner backing ring.

Oil sample collection – If needed, an oil sample (typically, a full quart or liter) can be collected at this time for later analysis.

5.3.2 Inspection and Maintenance of Gears

5.3.2.1 Introduction

The purpose of this section is to describe why gear tooth contact should be checked regularly, how the actual check is made, and how to interpret the tooth contact check on power transmission gearing with involute double-helical teeth and parallel input and output shafts.

5.3.2.2 Purpose of Checking Tooth Contact

Gear teeth must have an even load across the entire face width to minimize stress on the teeth. The contact between gear teeth is line contact; therefore, the alignment between the rotating elements (pinion and gear) is critical. Tooth alignment is controlled by the accuracy of the rotating elements, the housing, and the bearings assembly.

5.3.2.3 When to Check Tooth Contact

Tooth contact should be checked on all new installations, after any disassembly of the gear unit, and after any major housing-to-foundation change. It can also be checked as part of routine annual maintenance or when a problem related to alignment is suspected. Contact should be checked on the foundation being replaced to ensure that the unit will operate properly.

5.3.2.4 How to Check Tooth Contact

The contact can be checked two ways:

- **Soft blue** – Apply soft machinist's bluing or transfer bluing to the teeth of one gear and roll that gear by hand through meshing with its mating gear. (The terms "blue" or "bluing" are used for convenience; the dye is available in other colors. A soft blue check is usually run across a second element that is coated with another color, such as soft yellow. This contrast results in a more distinct, representative contact pattern.) The transfer of the blue from one gear to the other gear is read as the contact.
- **Hard blue** – Paint the gear teeth with hard or layout blue, run the gear unit, and observe the pattern of "wear off" of the bluing.

Contact checking may usually be accomplished through the inspection cover port. Occasionally, soft blue checking is done with the housing cover removed, such as during the reassembly process.

5.3.2.5 Interpretation of Tooth Contact

The following is information to be used only for guidance in deciding if tooth contact is adequate. In most cases, the gearbox manufacturer should be consulted on how to correct poor contact. Assuming properly manufactured parts, minor corrections can be made to the tooth contact by shimming the gear housing. Exactly what contact should be acceptable should be based on the manufacturer's recommendations and experience.

Maintenance personnel should remember that tip or root relief modifications are designed to improve load distribution when a unit is operating under load, but they can make the contact appear quite bad under no load, as in a soft blue check. Generally, with a soft blue check, one is looking for some blue to transfer, usually in a line that covers at least 80% of the face width, a centralized 60% coverage, or acceptable contact patterns consistent with those illustrated in Figure 5-3. Do not be alarmed by a lack of blue covering the flank of the tooth; flank contact should normally not extend entirely to the tip of the tooth.

Figure 5-3 illustrates various examples of tooth contact patterns. Keep in mind that a soft blue contact will not produce such dark impression— look for the same pattern in a "sketchy" impression.

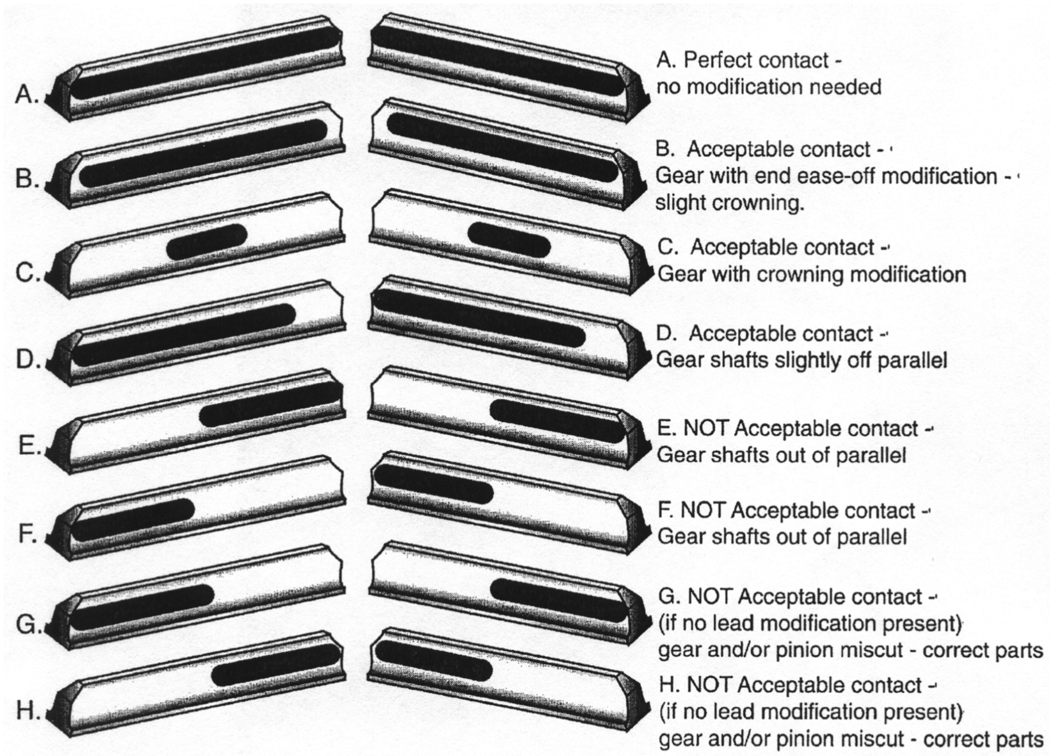

Figure 5-3
Tooth contact patterns
(Used with permission from Lufkin, Inc.)

The hard blue operational/running tooth contact check can be done from no load to full load, and the results will vary with the load condition. If the unit is run at no load, the test will usually appear similar to a soft blue check. More blue will wear off the pinion than the gear due to the higher number of cycles the pinion sees. As the load increases, blue will wear off more of the tooth flank. Look for evidence of even load across as much of the gear tooth, both flank and face with, as possible.

5.3.3 Maintenance of Bearings

5.3.3.1 Bearing Clearance

Measurement of bearing clearances can be done while the gear is stopped by lifting the shaft and measuring the distance traveled with a dial indicator or by using feeler gauges, carefully sliding a feeler gauge between the top of the bearing bore and the shaft.

Some wear should be expected, especially on a gear that is stopped and started frequently. The bearing may be considered operational as long as the measured clearance does not exceed the design clearance by more than 0.004 inches (101.6 microns). Note that if shaft vibration is excessive, this clearance increase may not be acceptable, especially on large or small bearings. For instance, a small 3–inch-(10.16-cm-) diameter high-speed bearing, with a design clearance of 0.003–0.005 inches (76.2–127 microns), could not withstand a clearance increase of 0.004 inches (101.6 microns). The clearance on the tilt pad bearings is difficult to check accurately and can normally be classified as acceptable if they show no signs of distress, damage, or excessive wear.

5.3.3.2 Bearing Contact Correction

After bearing contact is satisfactory, it may be possible to improve gear tooth contact by adjusting the shims under the unit. Do not attempt to modify the bearing contact of the tilt pad journal bearing in any way except by removing any localized nicks or dings (high spots).

Sometimes gear tooth contact can be corrected by scraping and polishing one of the bearings loaded in the bottom section to spread the contact along the face width. If this is necessary, the manufacturer should be contacted.

After correcting bearing and tooth contact and before putting the cover on the gearbox unit, the bearings should be liberally lubricated with clean oil to provide for initial startup lubrication.

5.3.3.3 Correcting Bearing High Spots

Bearing high (bright) spots should be lightly scraped and polished with fine steel wool or crocus cloth until they blend in with the rest of the bearing.

5.3.3.4 Flaking of Babbitt

If flaking is caught in the early stages, the bearing may be repaired by scraping and polishing. The cause of vibration or hammering should be corrected before the gearbox unit is put back in service. In the advanced stages of flaking, the load carrying area of the bearing is typically destroyed, and the bearing must be replaced.

5.3.3.5 Correcting Bearing Scoring

A little scoring is not serious, and the bearing can be polished with fine steel wool to remove any rough edges caused by scoring. Any foreign particles embedded in the babbitt that could score the journal should be carefully picked out, and that area should then be polished smooth. Scoring becomes serious when it significantly reduces the bearing area. In this case, the bearing should be replaced, and the gearbox unit drained and flushed out with a solvent.

Key Technical Point
Before replacing a wiped bearing, determine and correct the cause of the wipe.

5.3.3.6 Correcting Bearing Wiping

If wiping is localized in a small spot, the bearing can be repaired by scraping and polishing the spot until it blends in with the remainder of the bearing. Otherwise, the bearing must be replaced. Bearing scraping requires experience and expertise, however, as well as sound judgment when deciding whether to dress or replace the item.

5.3.3.7 Replacement Bearings

The manufacturer's parts list should be referenced if it is determined that bearings need to be replaced. If new bearings are used, the following precautions should be taken:

- Remove all nicks and burrs from the housing and bearing shell.
- Ensure that journals are free of nicks and high spots. These can be removed using a fine hone and polishing with crocus cloth.
- Obtain the proper bearing contact as described in the manufacturer's technical literature.
- After bearings are fitted and lower halves are installed in the housing, check the radial clearance using a feeler gauge or plastic gauge material. Check the end-play by barring the shaft axially.

5.3.4 Typical Procedure for Gearbox Reassembly

5.3.4.1 Preparation

The following reassembly sequence is provided for information purposes only and should not be used without reference to the manufacturer's instructions that are specific to the actual gearbox installed at the site. Note that any work done on equipment during the manufacturer's warranty period without the written approval of an authorized manufacturer's representative could void the warranty. This procedure assumes that the gear housing is not removed from its foundation/support and that the original shaft alignment was correct. Additional information regarding shaft alignment techniques is provided in EPRI report *Shaft Alignment Guide* (TR-112449).

The reassembly sequence for the gearbox is as follows:

1. Clean all interior surfaces of the housing, the housing cover, and all components that will be reused. Parting line surfaces must be clean and smooth; use a spray-on paint and gasket remover fluid, and/or carefully scrape the surfaces if necessary. Corroded spots can be cleaned by using a fine emery cloth, rubbing shafts in a rotary or circumferential direction. Do not rub shafts in a lengthwise direction as it may cause seal leaks.
2. Check the bearing shells, the parting line, and the housing bores for any burrs or nicks; remove with a fine file.

3. Put a coat of light oil on all parts to help assembly and to prevent rust during reassembly. Use fresh oil from the gearbox supply for this. Do not use special oils, such as STP, because their separate additives may cause operational problems.

The guidance in the following sections is assumes that the entire unit must be reassembled. NOTE: Tighten connectors uniformly. When tightening bolts, studs, or screws on an assembled portion with three or more holes, always partially tighten the connectors equally in a "cross" pattern to avoid torquing, binding, or warping the section.

5.3.4.2 Typical Reassembly Sequence

Although instructions include using sealer between housing sections, this should actually be done on the final assembly, only after checking tooth contact and ascertaining that the unit is aligned properly. Following is the procedure for reassembling the bearing, gear, and pinion assembly.

1. Install the journal bearings – Before installing the journal bearings, note that the pressure dam bearings are match marked and are not interchangeable.

   A. Install the lower half of the low-speed journal bearings (the half with the slot for the roll pin if there is one) in the housing in the position for which they were marked at disassembly, keeping the parting lines on the bearing and housing even.

   B. Check with a 0.0015-inch (38.1-micron) feeler gauge to see that the lower halves are seated. Consideration may be given to measuring the bearing clearance by direct measurement of the ID and the shaft journal OD. Another alternative is to use a commercially available plastic gage, (for example, a Perfect Circle Plastigage).

   C. Ensure that the pressure dam is seated in the correct location.

   D. Check the bearing contact as described in the instructions specific to the size, type, and model bearing in use. Do not attempt to install shafts with the lower halves of the thrust bearing in the housing, or babbitt-faced thrust faces may be damaged.

   E. Rethread any temperature sensor wires from the bearing through the housing.

2. Install gear – Lift the low speed gear, and carefully place the assembly in its correct location in the gear housing and bearings. Use care to avoid bumping the housing or the edges of bearings.
3. Set the top of the gear bearings in place, and secure it (use bolts or bearing straps if they are supplied). Turn the bearings in the bore if necessary.
4. Install pinion – Install the pinion bearings on the pinion, ensuring that the pinion is level, and line it up in mesh with the gear.

5. Carefully set the pinion and its bearings in mesh with the gear, and roll along the gear until the bearings are seated in the housing.
6. Line up the pins in the housing grooves, and rotate the bearings until seated.

Following is a typical procedure for assembling the gear cover:

1. Lower the cover over the studs carefully to prevent damage to gearing. Leave it suspended high enough to reach the RTD holes.
2. Thread the temperature sensor wires from the bearings as necessary to retain the leads extending into the housing.
3. Coat the split line with a small bead of sealer, such as LocTite No. 49-31 Plastic Gasket, or an equivalent plastic gasket material. Circle all the studs to ensure sealing of the oil, but avoid the feeder groove areas.
4. Seat the cover onto the bottom section, and install the cylindrical dowel pins. CAUTION: Do not assume that the doweling is accurate. Straight dowels have clearance, which over time may have come out of tolerance. Consideration may be given to using tapered dowels if dowel clearances prevent the proper seating and positioning of the gearbox cover.
5. Tighten all cap screws and studs in accordance with the manufacturer's recommended instructions. Typical torque values for Grade 5 bolts and studs are provided in Table 5-1.
6. Perform a soft blue gear tooth contact check in accordance with the guidance contained in this report.

Table 5-1
Recommended tightening torques
(Used with permission from Lufkin, Inc.)

Nominal Size		**Tightening Torque for Bolts**		**Tightening Torque for Studs**	
Inches	mm	Ft. Lbs.	N-m	Ft. Lbs.	N-m
1/2	12.7	75	102	87	117
5/8	15.9	150	203	173	234
3/4	19.0	266	360	307	416
1	25.4	644	873	742	1006
1-1/4	28.8	1120	1519	1484	2012
1-1/2	38.1	1949	2643	2582	3501
1-3/4	44.5	2286	3100	4073	5522

7. If the contact is not acceptable, check for improperly meshed gears, burrs on shafts or housing bores, or twisted housing. If no satisfactory explanation can be found, contact the manufacturer.
8. Install the thrust bearing:

    A. Replace the inner backing ring. It must be firmly seated against the wall of the housing.

    B. Thoroughly clean each thrust bearing shoe.

    C. Apply a liberal quantity of thick grease to the back side of each thrust shoe. The grease will serve as a temporary adhesive to keep the shoes positioned in the backing ring as they are installed.

    D. Install the inner thrust shoes, taking care to place each shoe that has an embedded temperature sensor in its original position.

    E. Install and tighten the thrust-collar lock nut, and tighten the two thrust-collar set screws.

    F. Install the axial-probe target plate.

    G. Place the outer backing ring on a flat surface. Apply a liberal quantity of grease to the back side of each outer thrust pad, and position the thrust shoes on the backing ring. Ensure that the shoes with embedded temperature sensors are located in their original position.

    H. Lift the outer backing ring assembly, and install it into the thrust bearing housing.

    I. Install the adjusting shims and thrust-bearing end cap, and tighten securely. Be very careful while handling and installing the shims, since torn or crimped shims can cause incorrect adjustments.

    J. Install temperature sensors in their shoes through the access covers.

9. Measure to ensure that the low-speed shaft has the specified axial movement. (Use a pry bar to move the gear from side to side if necessary.) Also check that the high-speed pinion can float axially.
10. Mount the shaft seals, end plates, and other auxiliary equipment that may have been disconnected during disassembly.
11. Reconnect any junction box plate and wiring as necessary.
12. Reconnect any instrumentation and lubrication lines as necessary.
13. Couple the unit to the driver and driven machines.
14. Install the inspection covers with gaskets and sealers.
15. Align the unit.

16. Spin the unit slowly with no load, if possible, to verify correct reassembly. Ensure that the unit rotates freely and quietly.
17. Confirm proper shaft alignment and tooth contact.
18. Follow the manufacturer's startup procedures.

5.4 Repair and Replacement of the Generator

Repair and replacement of the generator should be coordinated with the original supplier of the wind turbine (if still under warranty) or with the original generator manufacturer. Detailed guidance specific to each particular make and model of wind turbine generator is outside the scope of this report.

Section 6: Troubleshooting Guidance

6.1 System Troubleshooting

Figure 6-1 illustrates the generic process for performing preliminary troubleshooting of a given power generation system, such as a wind turbine. The figure emphasizes the need to define the problem, determine and validate system operating conditions, and subsequently determine whether the symptoms adversely affect system or component performance or reliability.

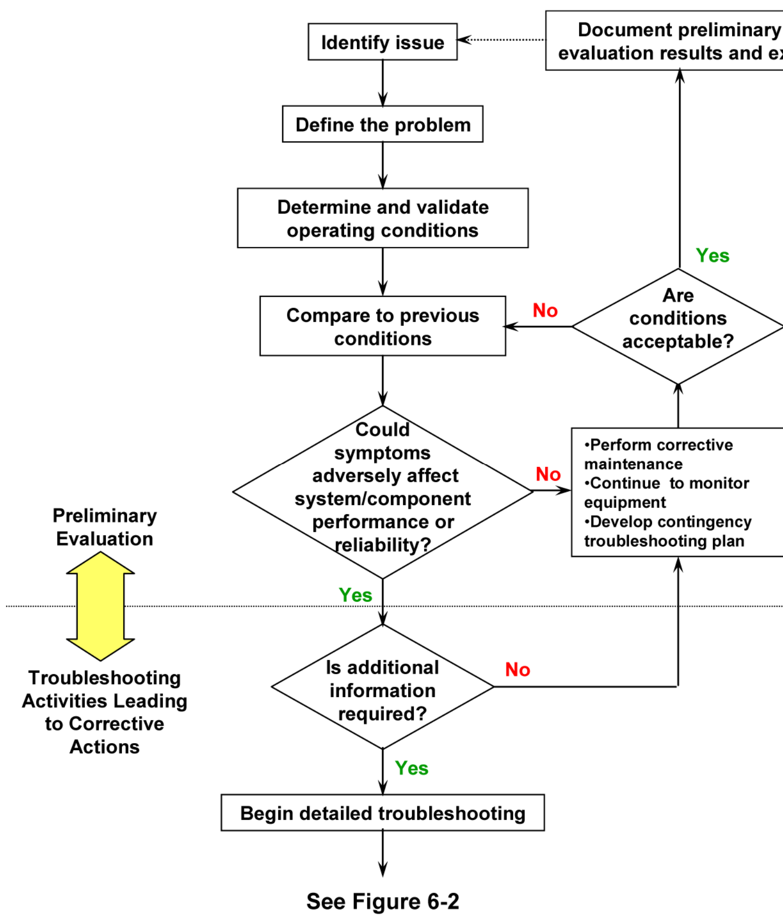

Figure 6-1
Generic process for system troubleshooting (preliminary evaluation)
(From EPRI 1003093)

Figure 6-2 illustrates the detailed system troubleshooting process that can be undertaken to investigate the symptoms and performance problems being experienced. The figure emphasizes the need to identify failure modes, develop a troubleshooting plan (especially if the system is evaluated while online), identify the cause(s) of the problem, and restore system performance. Additional guidance regarding system and component troubleshooting is provided in EPRI report *System and Equipment Troubleshooting Guideline* (1003093).

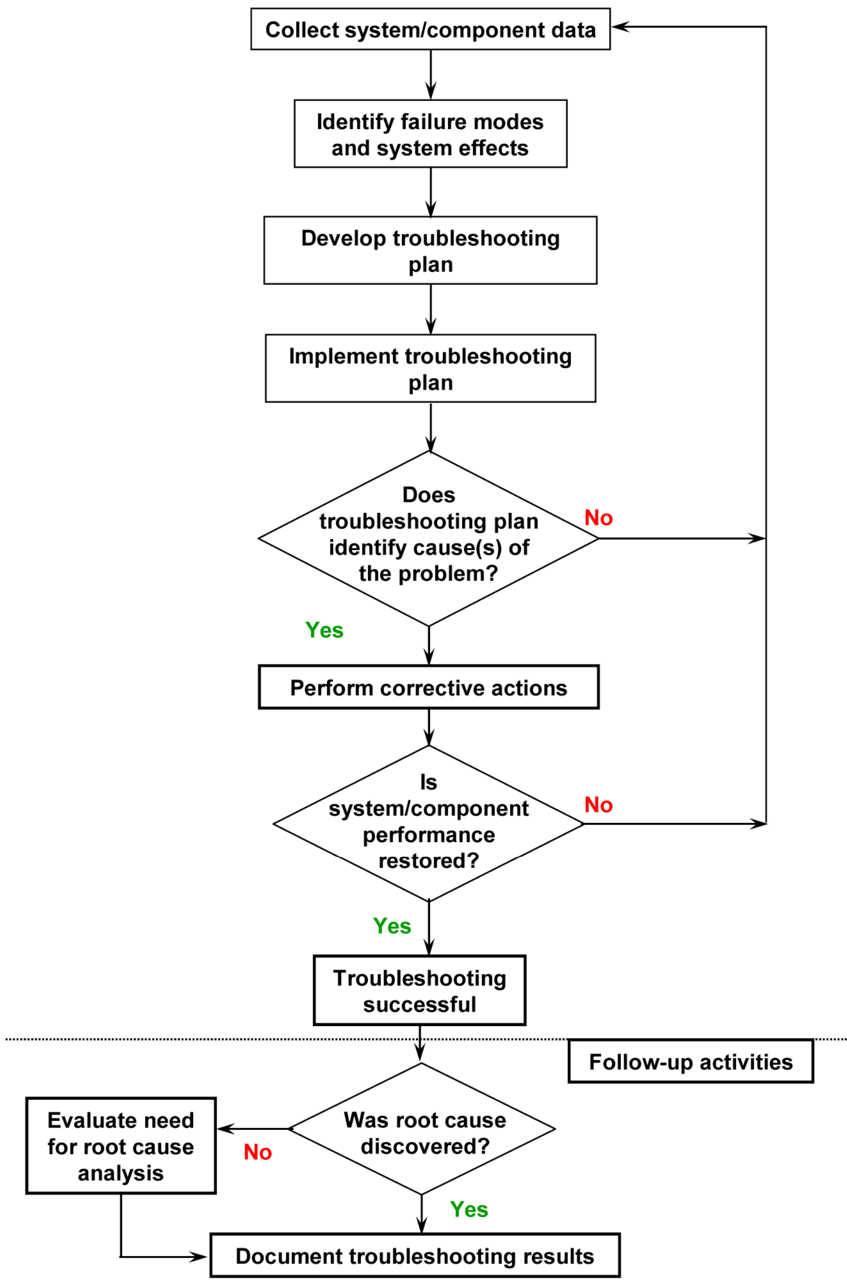

Figure 6-2
Generic process for system troubleshooting (detailed system troubleshooting) (From EPRI 1003093)

6.2 Troubleshooting of Wind Turbine Components

Troubleshooting of wind turbine components such as blades or components making up the nacelle, tower, or hub should be conducted in close cooperation with the original wind turbine manufacturer. Some of the most common failure mechanisms for failures of these components are discussed in Section 2 of this report.

Because of the complexity of many of the system components integral to a wind turbine system, troubleshooting should be performed in accordance with each equipment manufacturer's equipment-specific recommendations, which are typically provided in the manufacturer's technical manual. Detailed troubleshooting guidance for any of these subcomponents (for example, computers, switches, couplings, etc.) is outside the scope of this report.

Guidance regarding the performance of root cause analysis that may be necessary after experiencing a failure of wind turbine components is also outside the scope of this report.

6.3 Troubleshooting of Gearboxes

Table 6-1 provides summary troubleshooting guidance for gearboxes. The table identifies a number of problems associated with degraded or abnormal gearbox operation, as well as presenting probable causes and suggesting appropriate corrective actions. More detailed guidance is provided in the sections immediately following the table.

Table 6-1
Troubleshooting matrix for gearboxes
(Used with permission from Lufkin, Inc.)

Problem/ Symptom	Possible Cause	Corrective Action
Abnormally high temperature	Oil level too high	Check the sight gauge operation. Ensure proper drainage.
	Housing coated with foreign material, preventing heat dissipation	Clean the outside of the housing.
	High ambient temperature	Provide adequate ventilation.
	Lack of oil to bearings and/or mesh (indicated by low oil pressure)	Check the lubrication system.

Table 6-1 (continued)
Troubleshooting matrix for gearboxes
(Used with permission from Lufkin, Inc.)

Problem/ Symptom	Possible Cause	Corrective Action
Low oil pressure	Use of lubricant with a lower viscosity than required	Use the correct viscosity lubricant.
	Low lubricant viscosity from high lubricant temperature	Take the corrective actions noted for the abnormally high temperature problem/symptom.
	Clogged oil filter	Replace the filter element.
	Clogged air filter	Clean or replace the filter element.
	Pump cavitation	Maintain the proper oil level in the reservoir.
	Air leak in the suction line	Check and tighten all pipe fittings.
	Incorrect relief valve setting	Set the relief valve correctly.
Unusual noise	Worn parts	Pinpoint the noise with a mechanic's stethoscope. Replace the part.
	Coupling misalignment	Realign the coupling.
Excessive noise	Worn gearing	Replace the worn parts.
	Transmission from other equipment	Add a sound blanket or enclosure.
Excessive vibrations	Insufficient foundation rigidity or grout voids	Reinforce or repair the foundation.
	Dynamic instability (critical speed)	Design to attenuate critical speeds in the operating range.
	Unbalanced parts	Determine which parts require balancing and which have been balanced.
	Loose foundation bolting	Tighten the bolting.
Excessive foaming	Air in the oil	Add an anti-foaming agent.
No sensor readings	No power	Check the power supply, and repair or restore.
	Faulty gauge or recording device	Test the gauge or recording equipment.
	Failed sensor	Replace the sensor.
	Lead wire braid rubbed through (wire contacting metal)	Replace the lead wire.

6.3.1 Abnormally High Temperature

- **Oil level too high** – If the oil level in a gear box is so high that the gear runs in the oil, the resulting churning action will heat the oil. Check the sight gauge while the unit is running. A full gauge may indicate inadequate drainage.
- **Coated housing** – If the gear housing should get coated with a foreign material that will not permit natural heat removal by convection, high temperature may result. To prevent this, the unit should be cleaned periodically.
- **Hot weather** – Obviously, a high ambient temperature will cause abnormally high oil temperature. To prevent this, provide adequate ventilation around the gear.
- **Low oil pressure** – If the oil flow to the bearing and gear mesh is below normal (indicated by below normal oil pressure), the heat created by friction at the mesh and bearings will cause abnormally high temperatures. To correct this situation, check the lubrication system for proper operation.

6.3.2 Low Oil Pressure

- **Use of a lubricant with inadequate viscosity** –Several orifices in the lubrication system are sized for lubricants with a particular viscosity. A lubricant with less than this normal viscosity will pass through the orifices without building up pressure. This situation can be prevented by using the lubricant viscosity grade that is designated on the name plate of the gear unit. Abnormally low viscosity may also result from high lubricant temperatures.
- **Clogged oil filter** – Replacing the filter will allow more oil to flow through it, thus bringing the oil pressure back to normal.
- **Clogged air filter** – Cleaning or replacing the filter will allow more air to flow through it, allowing the gearbox to equalize to atmospheric pressure.
- **Pump cavitation** –If the oil level in the reservoir is so low that the pump suction line sucks both air and oil, the oil pressure will drop. This situation may be remedied by maintaining proper oil level in the reservoir.
- **Air leak in the suction line to the pump** – This situation is similar to pump cavitation in that air gets in the oil and results in low oil pressure. To remedy this problem, check and tighten all pipe fittings in the suction line.
- **Incorrect relief valve setting** – Adjusting the relief valve setting properly will avoid venting the pump discharge line back to the sump.

6.3.3 Unusual or Excessive Noise

- **Worn parts** – One common cause of unusual noise is worn parts. If a part wears enough to cause slack in the system, the slack may be heard as a rattle or noise of some sort. A mechanic's stethoscope can be used to pinpoint the worn part that should be replaced.
- **Misalignment** – A coupling that is out of alignment may also cause noisy operation. The misaligned coupling causes misalignment in the gear train, which then produces noise or vibration. The coupling should be immediately realigned before damaging wear occurs.
- **Transmitted sound** – Occasionally, other machinery or equipment may be transmitting excessive noise. Enclose one or the other, or use a sound blanket.

6.3.4 Excessive Vibration

- **Soft foundation or grout voids** – A foundation that is not sufficiently rigid may cause vibration problems. To correct this, reinforce the foundation.
- **Critical speeds** – At certain speeds, a rotating shaft will become dynamically unstable, and the resulting vibrations and deflections that occur may cause damage to the gear unit. The speeds at which the shaft becomes unstable are called *critical speeds*. They are a function of the shaft geometry and the type and spacing of the supporting bearings. If such dynamic instability is suspected, the manufacturer should be contacted. .

6.3.5 Foaming

- **Excessive foaming** – Some foam in a gear unit is generally acceptable and inevitable. If the foam exceeds 2 or 3 inches (5.05 or 7.52 cm) in the sump, most manufacturers recommend adding an anti-foaming agent (such as Dow Corning 200 Fluid, or the equivalent) at approximately 0.075 ml per gallon (3.78 liters) of oil. If excessive foaming persists, the manufacturer should be contacted. Care should be taken to measure the anti-foaming agent carefully. Too much anti-foaming agent will stabilize the foam, destroy the load capacity of the oil, and require a complete oil change.

6.3.6 No Sensor Readings

Various sensing devices for temperature and vibration are typically installed to provide warnings that can prevent catastrophic failure. If no readings are being received, check for the following before disassembling the unit:

- **No power** – Check that the power supply to the devices is on.
- **Failed equipment** – Check that the monitoring or recording equipment is functioning.
- **Worn wires** – If the sensor has failed, partial disassembly may be performed to replace the sensor. Visual inspection of lead wire over-braids are necessary to ensure that moving parts are not rubbing through the lead wires and causing shorting out. Replace any worn wires.

6.4 Generator Troubleshooting

The purpose of this section is to discuss the nature of numerous types of failures associated with generators and the causes of those failures, which may be useful when troubleshooting the equipment.

6.4.1 Cell Slot Liners

Since copper has a greater thermal co-efficient of expansion than steel and since ohmic heating occurs in the copper, the conductors of the field winding expand more than the steel of the rotor forging. This expansion of the copper can exert a force on the slot material in the direction of the expansion. The slot liner in some rotors can be dragged in the direction of expansion force. Cyclic operation of the generator will produce this thermal-expansion-caused dragging effect in each heatup of the field winding. Thus, the slot liners may be moved significantly over numerous cycles.

The movement, migration, or displacement of the slot liners can obstruct field-cooling passages, resulting in the possibility of significant blockage in the worst cases. Obstruction of the cooling passages leads to more heating of the conductors which, in turn, can worsen the movement of the slot liners. Additionally, other problems due to overheating, such as insulation degradation and copper distortion, can possibly occur.

Obviously, most generators do not experience slot migration as a problem. Well-designed machines provide for the thermal expansion of the conductors and secure the conductors effectively without creating shear stresses, which will move the slot liners. However, even in a well-designed machine, other problems may initiate liner movement. These other problems can include significant overheating of the field from excessive field current and a rotor rewind that was not up to specification.

The thermal expansion of copper can also cause fretting of the liner material. The movement of the winding against the liner (and the liner against the rotor steel if the liner moves) can abrade the liner material. Eventually, the liner may fail from the abrasion, leading to field grounds.

6.4.2 Winding Copper

Distortion of the rotor copper conductors, including foreshortening, elongation, and spreading, typically takes a significant period of time to develop. This distortion can lead to conductor and/or insulation failure. The copper conductors expand more than the rotor steel when heated during operation. If the conductor is unable to expand linearly, the copper will experience an axial compression. Blocking, friction, and pinch points from radial thermal expansion may all contribute to the constriction-free linear movement, causing the copper to be under compression. If compressive forces are above the yield point of the copper, deformation will occur. After this deformation or distortion occurs, foreshortening results as the conductor cools during shutdown or reduces loading.

The top conductors in the rotor slots are pressed by centrifugal force against the wedges and packing and can be more restricted from linear expansion than other conductors. This restriction can cause more distortion in the top conductors and produce more spreading of the conductors.

This spreading can be more significant at the ends of the rotor, where the top conductors are pressed against the retaining ring insulation. The winding end straps or turns may also be pressed by centrifugal force against the retaining ring insulation. As the retaining ring is expanded by centrifugal force, friction forces will pull on the top end straps. Over a number of operational cycles, the top end straps can undergo elongation and possible weakening.

Fretting damage to the insulation liner of the retaining ring can occur if the top end winding is pressed by centrifugal force against the retaining ring. Evidentially, fretting wear will perforate the insulation, creating a field ground. Possible arcing and resistive heating from a ground can damage both the end winding and the retaining ring.

Contributing to copper distortion is rotor overheating, which can cause softening of the rotor's copper. Copper distortion rarely, if at all, occurs in a relative short period of time, but rather develops slowly over years of operation.

Certain field winding designs incorporate two-part conductors. These two-part conductors are copper bars with C-shaped or E-shaped cross-sectional areas that, when installed face to face, form one or two cooling passages through them. One other two-part conductor design is composed of two flat pieces of copper that do not form cooling passages. Regardless of the shape of the two parts making up a conductor, relative movement between the copper parts can cause them to rub and abrade each other. This abrasion wears off some of the copper, forming copper dust. Relative movement of the copper conductor parts may be due to thermal expansion and slight rotor flexing experienced during startup, operation, and cooldown of the generator. Being on turning gear for a period of time may cause significant copper dusting.

While on turning gear, the windings can be freer to move than when in operation: not having centrifugal force or thermal expansion to hold the conductors tightly in position. With each rotation while on turning gear, the individual conductor parts complete a cycle of relative movement, with possible wear against each other.

Many generator rotors with two-part conductors do not necessarily have problems with copper dusting. In these machines, the conductors are sufficiently braced to prevent relative movement or at least make any movement insignificant. With some designs, the conductor parts are brazed together in spots along their length to more effectively hold them in their relative position.

6.4.3 Links and Connections

The links and connectors for the rotor field winding, including the main field leads, are subjected to same centrifugal and thermal stresses as the winding copper. Pole-to-pole links and other connections at the rotor ends may be pressed against the retaining ring by centrifugal forces and elongated. Typically, distortion of the links and connections occurs first and will aggravate the condition causing the distortion, leading to cracking of the copper. Furthermore, the distorted copper may cause degradation of the retaining ring insulation and a possible electrical ground.

As leads and connectors are securely terminated at both of their ends, cyclic expansion and forces on these conductors can create high stress at or near the terminations. On rotors having problems with leads and connectors, often the problem has occurred near a termination.

Loosening of terminations and connections can lead to localized heating and flexing, which, in turn, create high-stress points. Loosening occurs over time from cyclic forces, vibration, and thermal expansion/contraction. Additionally, the ties and packing used to secure a connector can loosen over time. This loosening can also lead to increased flexure and fatiguing of the connector.

Bore copper provides a path for field current from the collector or brushless exciter to the windings. The bore copper is not subjected to significant centrifugal forces, as with the conductors at the circumference of the rotor. However, thermal cycling and cyclic rotation can lead to problems with the bore copper. Over time, though not always, the cyclic stress and flexing of the bore copper can lead to degradation of not only the copper, but also of its insulation, creating a field ground.

Hydrogen-cooled generators have seals on the radial studs at either one or both ends of the bore copper. The radial studs connect the field winding leads to the bore copper at one end and the collector to the bore copper at the other end. Generators with brushless exciters may have radial studs at the field end, using butterfly connectors at the shaft's end for connection to the brushless exciter. The hydrogen seals, as the name implies, prevent hydrogen leakage through the shaft. Cyclic stresses and flexing of the bore copper can also put strain on the radial studs and the hydrogen seals, potentially initiating seal failure and hydrogen leakage.

6.4.4 Retaining Rings

As previously mentioned for links and connections, the conductors at the rotor ends may be pressed against the retaining ring by centrifugal forces. Fretting wear of the retaining ring insulation can lead to conductor grounding and arcing damage to the retaining ring.

The retaining ring is the most stressed component of the rotor. Significant damage from arcing or other means can eventually cause mechanical failure of the ring, creating the risk of catastrophic destruction of the entire generator. The extreme hoop stress on the ring during operation tends to pull the ring apart, thus any significant damage or defect can weaken the ring to the point where it cannot resist the hoop stress. Cyclic operation of the generator, such as two-shifting, can cause more fatigue of the ring metal at the point of damage or defect, making that damage or defect more significant. Eventually, the ring weakens enough to come apart, with the high centrifugal forces sending pieces of the ring into, and possibly through, other parts of the generator.

Stress corrosion cracking (SCC) of the retaining ring has received significant attention from the power industry in recent years. Retaining rings typically of 18Mn5Cr or similar composition are susceptible to SCC when subjected to moisture. The shrink fitting of the rings on the rotor causes an ever-present stress on the rings; this stress with the presence of moisture leads to SCC. During generator operation, centrifugal force reduces some of the stresses. Thus, frequent startup and shutdown of the generator produces much cyclic stresses on the rings. The presence of moisture in contact with the ring and cyclic stresses on the ring from starting up and stopping the generator promote the propagation of cracking.

The stress component of this problem cannot be eliminated; therefore, the industry has to focus on the corrosion component of this problem. Monitoring of the cooling medium dryness and periodic inspection of the ring provide some assurance of the soundness of the ring material. The rings need to be properly protected from moisture, even during outages when the rings could be exposed to the atmosphere. Inspection for SCC can be difficult or even incomplete without removing the ring from the rotor.

Cracking can often occur on the underside of the rings where dye penetrant and other visible inspections cannot be readily performed while the rings are mounted on the rotor. Ultrasound testing can reveal possible defects on the underside of the rings, but it can miss others due to the configuration and composition of the ring. Extensive work is needed to remove the rings for a complete and thorough inspection. Ring material may need to be removed to eliminate some corrosion and defects, but only a limited amount of material can be removed without weakening the ring. Care has to be exercised when planning and performing ring material removal in order to not create new stress risers.

Replacement of the retaining rings with ones made of 18Mn18Cr stainless steel or similar material not susceptible to stress corrosion cracking is the best way to eliminate the risk of stress corrosion failure of the rings. Ring replacement is the recommendation of generator OEMs. However, until replacement rings can be procured and an outage planned to replace the rings, assuring dryness of the ring environment and periodic inspection during preceding outages is necessary.

The rotor forging area under retaining rings is subjected to high cyclic stress. Due to a compressive fit, the rings press down on the rotor teeth both at standstill and while on turning gear. At operational speed, centrifugal force relieves a significant portion of the compressive stress on the teeth from the rings. However, centrifugal forces press the field winding upward against the dovetails, creating a tensional stress on the teeth. The varying cyclic stresses on the teeth under the retaining rings, from generator startup and shutdown, can lead to fatigue cracking or top tooth cracking. Specialized machining of the teeth in the retaining ring seat area can be performed to minimize stress risers in this area and reduce the risk of cracking.

6.4.5 Collectors and Brushes

Carbon dust can build up in the collector area due to rapid brush wear, poor ventilation, or infrequent cleaning. Frequent inspection of the collector area, including the brush rigging, helps identify dust buildup and avert potential grounding and shorting of the field circuit. Inspection of ventilation filters helps ensure adequate airflow across the collectors to remove carbon dust, in addition to providing cooling of the brushes.

Carbon dust buildup can create a ground of the field circuit and at worst, if not removed, can cause a flashover on the brush rigging from one polarity to the other. Significant heat from the flashover arc can melt and damage the rigging, the brush holders, and the collector rings. Flashovers can also occur during in-service brush replacement from dropped brushes and loose pigtails. Brush holders specifically designed for in-service brush replacement minimize the flashover risk.

Another collector problem is footprinting on the rings. Footprinting is also referred to as *ghosting* and *photographing*. Footprinting occurs from a brush periodically losing or lessening its contact with the ring. The footprint is the result of the brush making better contact at that point on the ring. With the better contact, more current flows from the brush to that point on the ring, creating a footprint of the brush.

The ring surface may become hardened at the footprint, leading to a high spot on the ring. As the ring surface wears, the harder footprint area wears less, becoming relatively higher than the rest of the ring. Root causes for footprinting can include vibration, weak brush spring, loose brush, and a brush restricted from moving in its holder. Consequences from footprinting include increased brush wear and brush chipping.

Other collector problems are excessive ring wear, excessive brush wear, grooving, and brush arcing. Excessive wear of the brushes and rings can be due to a number of causes that include:

- Improper brushes
- Contaminates
- Insufficient moisture in the air

- Poor brush contact with ring
- Excessive brush pressure on ring

Contaminants and insufficient moisture can cause the surface film on the rings to deplete, thus increasing the friction between the rings and brushes.

6.4.6 Winding Insulation

The generator field winding insulation is subject to a variety of stresses from mechanical, thermal, and electrical actions. Fretting wear can occur from relative movement of the conductor against another object such as the slot wall or another conductor. High voltages and harmonic content can overstress the insulation and lead to its eventual failure. Overheating of the field, which may be due to high current, poor cooling, or other factors, causes accelerated aging of the insulation. Obviously, insulation failure causes field grounds and possibly shorts in the winding.

Shorted turns are not always readily apparent, up to 5% of the field turns may be shorted before the problem becomes noticeable through vibration or increased field current. However, while not necessarily apparent, a short turn can cause localized heating at the short as well as causing damage to components adjacent to the short. The installation of flux probes is often the best way to identify shorted turns. However, flux probe installation does require removal of the rotor during an outage.

Shorted field winding turns, if significant, can be indicated by operational characteristics, such as vibration and field current requirements. The characteristics depend upon the design of the machine as well as the extent of the winding shorts. There are some differences between two-pole and four-pole generators with regard to their reactions from running with shorted turns, as shown in Table 6-2.

Table 6-2
Characteristics of two-pole and four-pole generator field shorts

Two-Pole Machines	Four-Pole Machines
Vibration induced by differential heating of rotor forging	Less reaction to the differential heating caused by turns being shorted
No magnetic imbalance, except with significant shorted turns	Vibration induced by magnetic imbalance on the rotor
Increased field current required to maintain generator output	Increased field current required to maintain generator output
More tolerance to shorted field winding turns	Less tolerance to shorted field winding turns

While Table 6-2 can aid in indicating the presence of field winding shorts, detailed vibration analysis and offline electrical testing might be needed to confirm the presence of shorted turns without the aid of an air gap flux monitor. An air flux monitoring system can be quite useful in determining the presence of shorted turns.

The problems resulting from copper distortion can lead to insulation degradation and failure. In addition to fretting, crushing of the insulation can occur in areas where distorted copper presses against the insulation. Additionally, insulation may degrade with age, although machines several decades old continue to provide reliable service with the original field insulation. Periodic insulation testing of the field winding will help to ensure reliable service for an operating cycle until the next scheduled outage.

6.4.7 Contamination

Contamination and debris can create insulation abrasion, wear, punctures, and eventual failure. Additionally, conductive contamination leads to field grounds and shorts. Chemical contaminants may attack the insulation, softening or degrading it so that even normal operational stresses fail the insulation.

Debris from installation, manufacture, and generator maintenance can be left in the generator if adequate measures are not taken to ensure cleanliness. In addition to the insulation damage described in the previous paragraph, tools and other relatively large objects can cause extensive damage to both the rotor and the stator. One instance involved a small file left in the air gap of a gas turbine generator. The rotor damage was repairable, but was so excessive that a long outage extension would be required for repair. A spare rotor had to be procured from another plant to allow the generator to be returned to service sooner.

6.4.8 End Winding Blocking

End winding blocking serves to maintain the conductors in the proper position, to provide support, and to prevent undue conductor movement. Age and vibration tend to cause loosening of the blocking, thus allowing undesired movement of the conductors. Elongation and other distortions of the conductors also contribute to loosening of the blocking.

Moved or missing blocking allows undesired movement of the end winding conductors, which in turn leads to further elongation, distortion, and possible conductor cracking. Conductor movement may also lead to fretting and insulation failure with possible damage to the conductors and retaining ring. Additionally, shifted and missing blocking can result in unequal transfer of conductor thermal expansion forces to the rotor forging, thereby possibly causing a slight bow and vibration to the rotor.

6.4.9 Rotor Cooling

Rotor cooling problems originate from both rotor design and rotor dynamics. Design-related problems include cooling path length, incomplete conductor cooling, restricted cooling paths, and unsecured slot components. Some rotor designs have long cooling paths through the slots, resulting in insufficient cooling near the exit points of these paths. The cooling gas (for example, hydrogen) heats up as it travels axially, cooling the conductors; at the end of its cooling path, the heated gas has diminished capacity to cool the conductors.

Air-cooled generators rely on the rotor to move air through cooling passages. Directly air-cooled generators draw air through filters to remove dust and debris. Clogged filters restrict air flow and reduce cooling capability, which can be especially troublesome during times of heavy load and high ambient temperature. Sufficiently clogged filters can collapse and dump dust and debris into the machine where cooling passages can become clogged. Indirectly cooled generators rely on a heat exchanger to cool the air. One generator design uses a sealed chamber beneath the generator, into which heated air is exhausted and then drawn through a heater exchanger to be cooled before returning into the generator. Debris left in air chambers and air pathways, after an outage, for instance, can clog the heat exchanger, restricting air flow and decreasing cooling capacity.

Slot cooling paths not designed for smooth aerodynamic flow restrict the flow of cooling gas, not allowing for optimal cooling. While a less-than-optimal flow does not necessarily cause inadequate cooling if other parameters, such as flow path length and high cooling gas temperature, are not adversely affecting the cooling. However, if these other parameters are deficient in conjunction with restricted flow, the cooling capability will be insufficient to prevent rotor overheating.

When conductors are incompletely cooled, portions of the conductors receive adequate cooling, while other portions do not. Incomplete cooling can be due to excessive flow path length, as described above. Also, incomplete cooling can occur where the design of the flow path omits points on the field conductors so that these points receive inadequate cooling. The insulation at these points suffers more from thermal degradation and may be damaged from increased expansion of the copper conductors.

Designs that do not adequately secure rotor slot components for the intended life of the generator may allow blockage of some cooling paths. The rotor, whether in operation or on turning gear, is constantly flexing a minute amount. The force of gravity bends the middle of the rotor downward, almost indiscernibly. This downward bending while the rotor is turning, even at speed, causes constant flexing of the rotor. The rotor slots are alternating under compression and tension, causing axial expansion and contraction of the slots. Slot liners, packing, and other components can be shifted by the alternating expansion and contraction, possibly causing them to interfere with cooling passages.

Additionally, thermal expansion and contraction from cyclic generator operation can contribute to the shifting of slot liners and other components.

Even with well-designed and manufactured rotors, some shifting of components should not be totally unexpected. After decades of operation, through wear and aging, components can become loose. With loosening, shifting of components becomes possible, to the extent that some blockage of cooling passages can occur. The resulting inadequate cooling, as mentioned before, can lead to conductor and insulation distortion and degradation in the affected areas.

Other issues that can adversely affect cooling include over excitation, shorted field turns, decreased hydrogen pressure, and decreased cooling water capacity. All these issues cause general overheating of the field, while shorted turns will also create localized hot spots. Typically, a short will not be a solid connection and will produce resistive heating. Additionally, shorts decrease the ampere-turns of the field, necessitating an increased field current to maintain the generator's excitation, and subsequently cause more resistive heating of the entire winding.

Maintaining the proper pressure ensures sufficient density of the hydrogen or other cooling gas to adequately cool the windings. A faulty hydrogen seal may necessitate running with decreased hydrogen pressure to minimize hydrogen leakage. Excitation may need to be decreased to prevent overheating with the reduced gas density and the subsequent reduction in cooling capacity.

The cooling gas is typically cooled by a gas-to-water heat exchanger. If the heat exchanger water flow is restricted or decreased, heat will not be as effectively removed as it should be from the cooling gas. Consequently, the temperature of the cooling gas will be too high to effectively cool the windings. Additionally, fouling of the water tubes in the heat exchanger or high water temperature will also diminish the heat transfer capability. Proper heat exchanger maintenance and attention to the chemistry of the cooling water help prevent fouling of the heat exchanger tubes. Load reductions may be necessary during periods of high water temperature to prevent rotor overheating. Water coolers or other modifications may be required to ensure sufficiently low cooling water temperatures for all periods of operation.

Overheating of the rotor and winding can occur from negative sequence currents from grid disturbances or motoring of the generator. While the situations are often transient in nature and usually rather brief in duration, sufficient overheating of the field winding and rotor iron may occur to distort conductor copper and damage winding insulation. Situations can occur in which low levels of negative sequence current may exist for long durations of time without being detected. These situations often result from unbalanced loading of the generator, resulting from untransposed transmission lines or a high amount of single-phase loading. The low level of negative sequence current might not be detected because many plants still rely on older electro-mechanical relays that may not be sufficiently sensitive. The negative sequence current induces current flow on the surface of the rotor, heating areas of the rotor, as well as possible arcing.

Regardless of whether overheating is transient or continuous and whether it is localized or general, damage to the field can occur. This damage may not be evident until long after the overheating event is over. Copper thermal expansion may have loosened components, leading to increased fretting wear and blocking of cooling. Damaged insulation may eventually fail, causing a ground or a short. Many winding shorts go undetected if they are minor and few in number. Moreover, these shorts can be worsened by localized resistive heating of the shorts, causing conductor damage, other shorts, and/or a field ground.

6.4.10 Forging Symmetry Issues

Shorted turns in the field winding likely will not be evenly distributed between the poles. As discussed previously, shorted turns produce general winding heating by causing a larger field current to compensate for the decreased ampere-turns. But also, because the shorts remove turns from the pole in which they occur, there will be uneven heating of the rotor.

The rotor forging, because of the uneven heating, will tend to expand more on the side that has the greater heating, causing a slight bowing of the rotor. Furthermore, the copper conductors expand more than the steel of the rotor forging and may exert additional forces acting to bow the rotor. These forces will be greater in the areas with more heating, thus contributing further asymmetry to the rotor.

Forging asymmetry manifests itself as vibration. Two-pole machines are much more susceptible to asymmetry from uneven rotor heating (thermal sensitivity) than rotors with four or more poles. The greater rotational speeds of the two-pole machine and the lower degree of initial symmetry make the two-pole rotors much more susceptible.

In addition to shorted turns, uneven heating may be due to blocked cooling passages. With cooling restricted in one or more passages, less heat is removed in the affected areas of the rotor, and uneven expansion will occur. Wedge tightness and end-winding blocking can affect a rotor's thermal sensitivity by changing the force transmitted from the conductors to the rotor forging. Varying tightness of wedges and uneven end-winding blocking can cause an asymmetrical variation of axial forces from the field conductors to the rotor forging. Additionally, variations in winding insulation thickness can restrict different conductors' axial movement, thereby also causing variations in the axial conductor forces acting on the forging, again impacting the rotor's thermal sensitivity. Variations in winding insulation may be due to design or manufacture, but more likely can occur from wear, crushing, overheating, or other damage to the insulation.

Repair of a short or ground may result in unequal insulation thickness, as well as a rotor rewind that did not ensure uniform insulation.

The asymmetry will seem to be an imbalance in the rotor, and, in fact, it is. However, unlike a typical imbalance, the thermal sensitivity asymmetry occurs only when field current heats the rotor. This asymmetry dissipates after the generator is taken offline and the rotor cools. During startup of the generator, the imbalance from thermal sensitivity asymmetry will also not be present until the field current again heats the rotor. Balance weights may correct this thermal unbalance during operation; however, the rotor will then be truly unbalanced at startup. Additionally, if the characteristics of the uneven heating change, such as from a field current change or changes of restrictions in the cooling passages, the thermal unbalance will return to some degree.

6.4.11 Rotor Shaft

Rotor shaft cracking can have catastrophic results on generators. Cracking starts small, almost unnoticeable, and then grows without any indication of trouble. Once the crack reaches a critical size, it can grow rapidly until it eventually results in shaft failure. Fortunately, until reaching that critical size, crack growth can be slow enough for detection by dye penetrant and other nondestructive testing techniques during scheduled outages.

Keyways, seating surfaces, and other machined areas on the rotor's shaft may be stress risers that, when subjected to strain from rotor flexing and vibration, initiate shaft cracking. Additionally, heat-shrunk components such as fans and couplings exert extreme pressure on the shaft and especially on nearby stress risers, adding to the strain and the possibility of crack initiation.

Crack initiation is dependent on the presence and configuration of the stress risers. Obviously, most generators do not suffer from potentially catastrophic crack initiation. Similar make and model generators will have similar susceptibility to cracking. However, different vibration characteristics and stresses on the rotor shafts can result in some differences in susceptibility, even for similar machines. Also, torsional vibration and operational events such as negative sequence currents can create forces that contribute to crack initiation and growth.

Typically, generator makes and models that do not have an industry history of shaft cracks will likely not develop the problem. Makes and models that do have a history of shaft cracking or those generators that have been subjected to abnormal forces such as from a system fault should be inspected for crack initiation. Susceptible machines will need periodic inspections until a modification is performed, if possible, to remove or minimize the stresses risers. After a shaft modification, inspections may be less frequent or possibly eliminated; however, at least one inspection should be performed after a post-modification operation to verify the effectiveness of the modification.

Vibration issues can be caused by adding a stub shaft to the rotor. A stub shaft is typically installed to support the collector rings due to modifications on the excitation system. These modifications include replacing a directly coupled rotating exciter with a static exciter; replacing a brushless exciter with a brushed exciter, or replacing a mercury bath collector with a brushed collector.

Usually, OEMs and other experienced service providers can supply and install a troublefree stub shaft. Great care must be taken in the design, manufacture, and installation of a stub shaft. A thorough vibration analysis of the generator rotor has to be performed to ensure that critical frequencies and other important rotor parameters are not adversely altered by the modification. The stub shaft will alter the rotor's axial, radial, and torsional vibration characteristics. Power system stabilizer responses might have to be adjusted to account for the changed torsional vibration characteristics. An inadequately designed and manufactured stub shaft can be very difficult to align and can create generator vibration problems.

6.4.12 Rotor Slot Teeth

Dovetail cracking has become a significant issue with owners and operators of large generators because these generators, in particular, tend to be more susceptible to this type of cracking. The middle of the rotors, being unsupported and undergoing more flexing than the ends, is more likely to have dovetail cracking. Most of the cracks can be detected when still small and can be readily repaired if inspections are performed. Causes of dovetail crack initiation and propagation are believed to include fretting on the teeth by the slot wedges, negative sequence current, and cyclic generator operation. Some recent analysis and studies indicate that fretting is not a major issue with regard to crack initiation, but rather damage from negative sequence current may be more responsible.

Fretting wear on the rotor teeth at the dovetails' load face has been thought to be a leading cause of dovetail cracking. The slot wedges press tightly against the teeth's dovetails and more so at speed due to centrifugal force. A rotor that is supported at its ends is bowed downward slightly due to gravity, with the most deflection at the rotor's middle. Although this bowing or deflection of the rotor is indiscernible to the unaided eye, it is sufficient to cause an increase in the length of the bottom of the rotor. As the rotor turns, points on the circumference undergo lengthening as they pass beneath the rotor's centerline and then contracting as they pass above the centerline. Thus, the length of the rotor slots and teeth will alternately lengthen and shorten as the rotor turns.

As the teeth lengthen and shorten with the turning of the rotor, the slot wedges held against the teeth's dovetail by the slot contents and by centrifugal force rub against the dovetail surfaces. This rubbing not only causes fretting, but also causes alternating stress on the dovetail surfaces. The fretting and alternating stress can eventually lead to crack initiation. Often the resulting cracks initiate at stress risers such as cooling cross-slots. Once initiated, cracks often grow slowly until a critical size is reached, and then the crack can grow rapidly through the rotor tooth.

Crack growth continues by the actions of rotor flexure as the rotor rotates. Additionally, forces from thermal expansion and contraction in both the conductors and the forging act in the development and spread of the cracking. Previous stresses from negative sequence current and generator motoring also contribute to the initiation and progression of the cracking. The propagation and the critical crack size are unique to each machine. The design of the rotor, the operational parameters, and the history of the machine impact crack growth.

Cyclic operation of the generator such as two-shifting, that is, starting up the generator for part of the day to handle high grid loads and then shutting down for the rest of the day, can hasten crack development. Being on turning gear, speeding up when starting, and spinning down when stopping can produce more fretting by the wedges. At the lower speeds, the wedges are not pressed by centrifugal force as tightly against the dovetails as when at speed. The wedges, therefore, are freer to move against the dovetails at lower speeds.

Another factor in dovetail crack development is believed to be wedges made of steel. Part of the recommended solution to limit dovetail fretting is the replacement of steel wedges with ones made of aluminum. Aluminum wedges, softer than those of steel, do not impart as much fretting stress on the dovetails. So far, units using aluminum wedges have experienced significantly less dovetail fretting. Of course, since aluminum is non-magnetic, a detailed analysis of the field's electromagnetic characteristics and the impact of the aluminum wedges will need to be performed, as well as a mechanical analysis. Not all wedges will typically need to be replaced with aluminum wedges; typically, the middle two-thirds of the rotor will benefit the most from wedge replacement.

In addition to fretting damage during operation, slot dovetails can be and have been damaged from installation of the slot wedges. Care must be exercised with installing the wedges as with other components of the rotor. Whether the wedges are oversized, are jammed from slot packing, or are just a victim of poor craftsmanship, the damage is the same. The corners of the steel wedges can gall the surfaces of the dovetails. Damage to the dovetails, if not immediately repaired, will be a stress riser, which may initiate dovetail cracking.

6.4.13 Rotor Baffle Assembly

The rotor baffle assemblies are located at the ends of the forging and are designed to direct cooling hydrogen to the appropriate areas. Not all rotors use baffles. On the rotors that use baffles, the baffles can be subjected to vibrations that can cause fatigue of the assembly components and damage from loose rotor components and debris. Although not many instances of damage have been found in comparison to the number of units in service, cracks and other damage have been discovered during inspections. Typically, inspection and nondestructive testing of the baffle is recommended during generator outage disassembly. Usually, baffle assembly inspection requires retaining ring removal for full access to the assembly.

6.4.14 Slot Liners

As previously discussed, the slot liners are subjected to forces from rotor flexure and the thermal expansion and contraction of the conductors. These forces can be, in some instances, sufficient to move the slot liner axially. Liner movement or migration leaves the liner in the wrong position, which may block cooling passages and may expose parts of the slot wall to the field conductors.

The ends of the slot liners are subjected to more damage due to their being at the rotor ends, which typically have conductor movement and vibration. Additionally, the ends of the slot liners can be stressed from liner movement and from being pressed against other components and become damaged.

Fretting damage to the slot liners can occur from rotor flexure and conductor movement, even if there is no liner movement. Relative movement of the rotor and conductor wear on the slot liner and produce fretting damage that may lead to liner cracking. Poor practices during rewinds and during slot wedge installation may damage the liner. Cracked liners can be more susceptible to migration, and because the liner is ground insulation, cracking may lead to field grounds.

6.4.15 Rotor Fan

The generator cooling rotor fan is typically robust and not usually susceptible to damage. Not all rotors use fans, relying on the rotor cross-slots to move the cooling gas. Damage can occur to the fan during rotor removal and installation and during rotor maintenance. Rotor vibration can lead to fatiguing the fan's metal if excessive. A damaged fan can lead to increased vibration, and if the fan's damage is sufficient, the fan may throw pieces that will likely severely damage the generator.

6.4.16 Slot Wedges

The slot wedges hold the field conductors in the slots against centrifugal force and may also be designed to direct cooling gas into the slots. Due to centrifugal force, a slot wedge must handle significant stress. The wedge areas adjacent to the dovetails are the most stressed and often are where cracks initiate. In these areas, each side of the wedge stress risers may exist where the wedge is machined to fit in the dovetail. Rotor flexure and conductor movement can contribute to crack initiation and propagation.

A failed wedge can cause severe damage to both the stator and rotor and even cause catastrophic generator damage. Fortunately, wedge cracking is rather uncommon, and actual wedge failure is rare, especially when wedges are periodically inspected.

Centrifugal force will hold the wedges tightly in the slot dovetail doing operation. However, at low speeds during startup, during shutdown, and while on turning gear, the slot packing has to hold the wedges in position. Excessive packing clearance can leave the slot wedges relatively loose and possibly lead to fretting against the dovetail surfaces. Excessive packing clearance can also lead to movement of the conductors and other slot contents, causing fretting wear and distortion of the conductors. Movement of the wedges can restrict cooling because cooling passages in the wedges may no longer line up with the passages in the slots and in the rotor forging.

Section 7: Personnel Safety Issues

7.1 Personnel Safety Issues

Safety is a basic factor that must be considered at all times during the installation, operation, and maintenance of mechanical equipment. Through the use of proper tools, clothing, and procedures, serious injury and property damage can be prevented. Any accident, regardless of the situation, is generally the result of someone's carelessness or neglect. No amount of training or instruction can replace common sense, sound judgment, and acceptable work practices. A few general safety precautions are listed below for each major type of equipment described in this report.

7.2 Source Documents

The following documents provide detailed guidance regarding the safety of personnel performing maintenance, repair, and operations activities on a wind turbine:

- Standard for Electrical Safety in the Workplace, National Fire Protection Association, Quincy, MA: 2012. NFPA 70E.
- Wind Turbine Safety Rules (WTSR), RenewableUK (formerly known as BWEA), London, UK: 2011.

7.3 Recommended Practices

7.3.1 Using Approved Written Procedures

When work or testing is to be carried out on or adjacent to the wind turbine, that work or testing should be carried out under an approved written procedure. Before work or testing is to be implemented in accordance with the written procedures, the following should take place:

- The wind turbines on which the work or testing is to take place should be clearly defined.
- Except where the means of achieving safety from the system is by limiting the work (or testing) or the work area, the wind turbine should be isolated. When isolating devices are used, they should, where practicable, be immobilized and locked. Caution notices should be affixed at all points of isolation. Isolations that need to be removed in order for further work or testing to take place, including those necessary to make available essential testing supplies, can be removed or restored during the course of work or testing.

- The contents of the wind turbine should be adjusted to a level that avoids danger, and where drains could give rise to danger, they should be locked in the appropriate position.
- Where danger could arise from pressurization, the wind turbine should be vented, and where vents could give rise to danger, they should be locked in the appropriate position.
- Where internal access is required, the wind turbine should be purged if the residue of its contents could cause danger to personnel.
- Where danger could arise from the release of stored energy, appropriate actions should be taken to contain or dissipate this energy safely.

When work or testing is to be carried out on a wind turbine it may, in certain circumstances, be essential to restore motive power supplies. All such work or testing should be carried out in an approved manner under an approved written procedure, which should specify the circumstances and the method of dealing with hazards arising during periods of restoration of motive power. When motive power is to be restored, the requirements, specified in the approved written procedure, should ensure that safety is maintained prior to and after removing the isolation that allows this restoration to take place. Those actions should include the requirement to notify all personnel in the vicinity prior to restoring motive power supplies.

Only the work scope or testing specified in the approved written procedure should be carried out.

7.3.2 Safety Precautions When Working on Low-Voltage Equipment

The main dangers to personnel working on or testing low-voltage equipment are electric shock or burns arising from the following:

- The possibility of personnel mistaking the part of low-voltage equipment on which it is unsafe to work or test without special precautions for that which is isolated and on which it is safe to work or test
- The possibility of the low-voltage equipment being worked on accidentally or inadvertently being made live
- Inadequate precautions being taken under live conditions
- The uncontrolled release of stored energy in the low-voltage equipment

Where practicable, the low-voltage equipment should be isolated. When isolating devices are used, they should, where reasonably practicable, be immobilized and locked. When work or testing is to be carried out on low-voltage equipment, caution notices should be affixed at all points of isolation. When work or testing is to be carried out on or adjacent to low-voltage equipment, that work or testing should be carried out under an approved written procedure.

The low-voltage equipment on which the work or testing is to take place should be clearly defined, and only the work or testing specified in the approved written procedure should be carried out. The preferred method is to always work or test on or near low-voltage equipment that has been isolated. This will not always be practicable, but no person should be engaged in any work or testing on or so near any exposed live low-voltage equipment that danger may arise unless all of the following criteria are met:

- It is unreasonable in all circumstances for it to be dead.
- It is reasonable in all circumstances to be at work on or near it while it is live.
- Suitable precautions (including, where necessary, the provision of suitable protective equipment) are taken to prevent injury.

Even though live testing may be justifiable, it does not follow that there will necessarily be justification for subsequent repair work to be carried out live. Any subsequent repair work should be carried out with the low-voltage equipment isolated unless all the criteria listed above for live work are met.

When work or testing is to be carried out and it is not practicable to isolate the low-voltage equipment to remove hazards that could give rise to danger or if, during the course of work or testing, it will be necessary to remove such isolations, the work or testing should be done under an approved written procedure that should specify the method of dealing with those hazards. This should include the conditions under which the work or testing is to take place and the safety precautions necessary to prevent injury, including the circumstances and precautions for any live work or testing.

Where work or testing is to be carried out on low-voltage equipment that is part of high-voltage equipment or on low-voltage equipment that is in proximity to exposed high-voltage equipment that may be live or become live, high-voltage safety rules or their approved equivalent should be used.

When work or testing on low-voltage equipment requires portable instruments to be used for voltage or resistance measurements on circuits not otherwise adequately fused, the instruments or leads should be provided with fused protection or other suitable built-in protective devices to safeguard persons from danger.

When work or testing is to be carried out on isolated low-voltage equipment, the following should be done:

- Low-voltage isolation should be by the withdrawal of fuse links or other isolating devices. Time switches, float switches, thermostats, sequence switching devices, or similar automatic switching devices are not isolating devices and should not be used.
- When isolating devices are used, they should, where reasonably practicable, be immobilized and locked. If this is not reasonably practicable, the fuse links or other isolating devices should be removed.

- Where work or testing is to be done on portable or hand-held low-voltage equipment, isolation can be achieved by the removal of the plug from the socket outlet, provided that the plug remains in sight of the person doing the work or testing or the plug has a lockable device applied to it that prevents it from being inserted into a socket outlet.
- Safety keys should be placed in a suitably labeled envelope and, along with any removable isolating devices, should (except in circumstances when the low-voltage equipment is permitted to be made live) be retained in safe custody by the authorized technician holding the approved written procedure, preferably by retaining them in his personal possession.
- For ongoing work or testing, beyond one working day, secure retention of items taken into safe custody by the authorized technician should be in accordance with management instructions.
- In order to facilitate the handing over of isolating devices and safety keys, they must be readily identifiable with the approved written procedure and with the low-voltage equipment with which they are associated.
- Where work or testing is to be continued by another authorized technician, the transfer process should be implemented in accordance with the requirements of site wind turbine safety rules.
- Where adjacent exposed live low-voltage equipment is present that gives rise to danger, work or testing must be done only by an authorized technician who has completed an appropriate course of training as defined in management instructions and is appointed for work or testing adjacent to exposed live low-voltage equipment. The danger associated with any adjacent exposed live low-voltage equipment should be highlighted in the approved written procedure. The authorized technician should:
    - Where practicable, screen off any adjacent exposed or unprotected low-voltage equipment that may be considered to be live.
    - Where necessary to prevent injury, use approved insulated tools, stands, mats, insulating gloves, or other personal protective equipment as appropriate, and remove metallic objects from the hands and wrists. In addition, consideration should be given to the authorized technician being accompanied by another authorized technician if their presence could contribute significantly to ensuring that injury is prevented. Any accompanying authorized technician should be trained to recognize danger and, if necessary, to render assistance in the event of an emergency.
- Before work or testing begins, the authorized technician should check, by means of an approved voltage-testing device, that the low-voltage equipment on which work or testing is to be done is **not** live. The instrument used should be tested immediately before and after use.

When work or testing is to be carried out on live low-voltage equipment, work or testing may be done with the low-voltage equipment live only under the following conditions:

- The fact that the work or testing is to be carried out on live low-voltage equipment should be highlighted in the approved written procedure that should specify to the authorized technician how the requirements under this safety rule are to be met.
- The work or testing should only be done by an authorized technician who has completed an appropriate course of training as defined in management instructions and is authorized for work or testing on live low-voltage equipment.
- The authorized technician who is to do the work or testing should first remove any metallic objects such as wristwatch, rings, wristlets, cufflinks, earrings, pendants, and other items of personal jewelry.
- All adjacent metal that is electrically bonded to earth or conductors that are at a different potential from that on which work or testing is to be carried out must be screened with insulating material to avoid danger. The material used for screening must be of sufficient strength to withstand an accidental blow from a tool without tearing or otherwise ceasing to be effective.
- Where necessary to prevent injury, approved insulated tools, insulating stands or mats, insulating gloves, eye protection, face-shields, and protective coveralls, as appropriate, must be used. When considering the extent of personal protective equipment to be used, due account should be taken of the fault level of the circuit concerned and the potential danger from arcing.
- Only suitable test instruments and test probes should be used.
- Consideration should be given to the authorized technician being accompanied by another authorized technician(s) if their presence could contribute significantly to ensuring that injury is prevented. Any accompanying authorized technician should be trained to recognize danger and, if necessary, to render assistance in the event of an emergency.
- Before beginning work or testing in ducting, trenches, or underground distribution boxes where there is a foreseeable possibility of the presence of gas that might be inadvertently ignited by electric sparks, a special work permit should be obtained. Prior to beginning work or testing, any additional precautions specified by the special work permit that are necessary to remove or prevent danger should be implemented in accordance with management instructions.

7.3.3 Demarcation of Work Areas

The work area should be defined clearly and, where necessary, protected physically to prevent danger to persons in the work area from system hazards adjacent to the work area.

7.3.4 Identification of the Wind Turbine and Low-Voltage Equipment

Work or testing should be permitted to start only on the wind turbine and/or low-voltage equipment that is readily identifiable or has fixed to it a means of identification that will remain effective throughout the course of the work or testing.

7.3.5 Automatically or Remotely Controlled Wind Turbines and Low-Voltage Equipment

All wind turbine and low-voltage equipment associated with any wind turbine should be considered as automatically or remotely controlled. Control over the operation of the wind turbine and low-voltage equipment can either be by local (on-site) or remote (off-site) means. The means of control over “local” on-site operation may be physically remote from the wind turbine and low-voltage equipment that is being worked on.

When personnel are working on or testing wind turbine and/or low-voltage equipment that has automatic or remote control features, the main danger that could arise is from the operation of the wind turbine and/or low-voltage equipment if these control features have not been isolated. Where danger could arise to personnel at work on or testing such wind turbines and low-voltage equipment, all such automatic or local/remote operation should be prevented while the work or testing is taking place.

Where work or testing is to be carried out on automatically or remotely controlled wind turbine or low-voltage equipment, the precautions taken to achieve safety from the system should cause all automatic or remote control features to be isolated. This requirement should also include any local control features. Where practicable, all such isolations should be locked and remain so for the duration of the work or testing. Caution notices should be affixed at all points of isolation.

The requirements for achieving safety from the system from all control features should be specified in an approved written procedure.

If it is essential to restore motive power supplies in order to complete the work or testing on the wind turbine and/or low-voltage equipment so that any automatic, remote, or local control features would become operable, then the approved written procedure should specify the means of maintaining safety while those control features are operable.

Work on, testing, or making of adjustments to the controlling features of a wind turbine or low-voltage equipment while it is in operating mode should be done only by an authorized technician who has completed an appropriate course of training as defined in management instructions and is appointed for that purpose. Before such work or testing begins, consultation should take place between the authorized technician and the operational controller. No other work or testing should be permitted on that wind turbine or low-voltage equipment at the same time.

When it is necessary to work on, test, or make adjustments to the controlling features with those features operational, but with the controlled wind turbine or low-voltage equipment not in operating mode, no other work or testing should be permitted on that wind turbine or low-voltage equipment at the same time.

7.4 Excavation

When work or testing at or around the wind turbine involves excavation, it should always be undertaken by following the requirements of the site's high-voltage safety guidelines.

7.5 Confined Spaces

When work or testing on or around wind turbines requires access to a confined space in which, by virtue of its enclosed nature, a reasonably foreseeable specified risk arises, guidance on the precautions to be taken should be defined in authorized site procedures.

Key Human Performance Point
Permits should be required to control the number of people entering confined spaces. Typically, due to high CO content (if batteries have failed), the number of personnel entering a confined space should be limited to four.

In deciding whether there is a reasonably foreseeable specified risk, the nature of the work or testing itself should be considered.

The detail of the precautions that are required, associated with that work or testing, should be specified in an approved written procedure.

7.6 Occupational Safety Requirements for Work on Wind Turbines

7.6.1 General Guidance

The following general guidance for occupational safety should be integral to site procedures in order to ensure that appropriate safety measures are consistently implemented:

- Everyone who requires personal safety equipment to prevent them from falling must be informed of this requirement. In addition, they must also receive instructions about proper conduct on and within wind turbines and about rescue procedures and equipment. These instructions must typically be documented.
- Furthermore, everyone who performs work on wind turbines must be properly instructed about all of the dangers and risks that can occur when their work is being performed or as a result of their work, such as the risks involved in working with electricity, working with special tools (such as hydraulic screwdrivers, special measurement equipment, etc.), work with certain materials (such as toxic materials, particles, etc.), or any special activities that are not part of a standard procedure or that have to be repeated. The worker or contractor assigned the work must perform a risk analysis to determine the dangers and risks and implement the protective measures required.

- An adequate number of people who can administer first aid must be on hand when work is being performed. Maintenance work generally requires two technicians, and both of them must be trained in first aid. At construction sites, at least two people must have such training.
- Proper communication must be provided in all activities that require it.
- All of the equipment needed to perform tasks—such as personal safety equipment, noise protection, protective gloves, protective glasses, rescue equipment, breathing masks, etc.—must be provided before work has begun. The contractor must perform risk analyses to determine which equipment is required for which activities for all of the tasks to be performed and implement the protective safety measures required.
- Everyone who performs tasks on or within a wind turbine should be trained and instructed on the tasks to avoid, for example, mechanics from working on switching equipment or electrical systems.
- . An expert must check the rescue equipment and personal safety equipment once a year to verify that the equipment is in good condition in order to prevent falling.
- All of the security aspects of a wind turbine—such as ladders, protection systems, elevators, electric hoists, pulleys, cranes, any rescue equipment for the wind turbine, personal falling protection equipment, etc.—must be inspected by a technical expert at least once a year.
- An expert must inspect all of the electrical tools used at least once a year or at more frequent intervals at construction sites.
- If work is done on the hub, the rotor blades, the area of the tower near the rotor blades, etc., the rotor must be kept still mechanically; it is not sufficient to simply use the mechanical brake when work is being done.
- The lighting on the inside and outside of the wind turbines must be appropriate for the tasks.
- The clothing worn must be appropriate for the weather conditions in order to protect the wearer from rain, cold, wind, etc.
- Operating instructions must be created for all dangerous materials, tools, etc. and complied with whenever work is being performed.
- Emergency procedures must be specified, for example, to rescue personnel, put out fires, etc.

7.6.2 Safety Issues During the Assembly of Wind Turbines

The following occupational safety guidance should be integral to site procedures to ensure that appropriate safety measures are consistently implemented during the construction of wind turbines:

- The owner of the construction site must appoint a safety coordinator before construction begins because this work is dangerous. This person will coordinate all activities, such as access roads, cabling, assembly, etc.; create a safety and health plan; and inspect the construction site regularly in order to prevent accidents from happening when various tasks are being performed simultaneously.
- When wind turbines are being set up and work is being done with cranes, the general requirements on construction sites are to wear helmets and protective shoes of class S3 (protective flap and impenetrable sole). These procedures are mandatory for everyone on the site, including those not directly involved in construction (the owner of the farm, local authorities, suppliers, visitors, etc.).
- In general, all of the parties directly involved in the installation of wind turbines (crane company, suppliers, mechanics, etc.) must take part in security training before work begins. The training sessions must cover all aspects related to security at construction sites and be documented.
- All of the legal requirements must be fulfilled for facilities at the construction site, such as relaxation areas, toilets, showers, certified ladders, fire extinguishers, first aid kits, appropriate signs, etc.
- All of the fastening materials and lifting equipment used, such as ropes, belts, special lifting equipment for the tower, machine cases, rotor blades, etc., must be inspected regularly by experts and certified as appropriate for use before being put into operation. The fastening materials and lifting equipment must be appropriate.
- Lighting must also be sufficient outside and inside the wind turbine.

7.6.3 Safety Issues During Maintenance of Wind Turbines

The following occupational safety guidance should be integral to site procedures to ensure that appropriate safety measures are consistently implemented during maintenance and servicing of wind turbines:

- Access roads and paths that lead to wind turbines must be kept navigable; that is, they should be smooth to prevent people from stumbling, kept free of plants, be sufficiently wide, have railings if there are more than five steps, sloping access ramps should not be too steep, etc.
- The fastening materials and lifting equipment must be appropriate for the task.
- All of the fastening materials and lifting equipment used, such as ropes, belts, etc., must be inspected regularly by experts and certified as appropriate for use before being put into operation. The fastening materials and lifting equipment must be appropriate.

7.7 Safety in Wind Energy When Using Cranes

The following guidance is recommended by the American Wind Energy Association (AWEA) and should be considered when using cranes on or around wind turbines.

7.7.1 General

Wind turbine construction requires some of the largest equipment in use today. Lifting components in excess of 81.7 metric tons to heights exceeding 300 feet (91.4 m) requires strict attention to safety. Every project in the wind industry is unique and will have project-specific needs, challenges, and safety requirements. Crane safety should be addressed when assessing the project needs and requirements. The information here is intended to provide general guidelines to help assist in safe project planning, which leads to safe project construction.

7.7.2 Hazard Analysis

Every wind project requires a hazard analysis of the work being performed. This analysis should include the crane operator's input, and all hazards should be identified prior to crane operation.

7.7.3 Assembly/Disassembly

Due to their size, cranes must be disassembled for shipping and reassembled once they arrive at the project. The Occupational Safety and Health Administration (OSHA) requires fall protection for heights at 6 feet (1.8 m) or above. A combination of personal fall arrest systems (PFAS), platforms, and or worker lifts are typically necessary to complete this work.

7.7.4 Inspection

A key component to crane safety is frequent crane inspections. OSHA requires that a competent person be designated to inspect the crane and associated equipment prior to each use as well as thorough, documented annual inspections. Cranes should also be shut down and re-inspected after any incident or occurrence that could affect the integrity of the crane.

7.7.5 Wind/Weather Considerations

Wind and weather wreaks havoc with construction schedules; nevertheless, Mother Nature and the laws of physics rule when it comes to crane operations. Never exceed the crane or component manufacturer's charts or recommendations pertaining to wind. Wind speeds should always be determined via a boom tip anemometer. It is essential to have a plan in place for lightning safety. The following are examples of equipment and components that should be checked to ensure that they are in good condition and/or operable prior to initiating work:

- All wire rope
- Rigging
- Belts, pumps

- Hoses
- Drive systems
- Brakes
- Clutches
- Computer
- Anemometer boom
- Anti-two-block device

7.7.6 Communication

Communication while performing work in the wind industry is essential. A single signal person might not be adequate for performing lifts. Workers should employ a system wherein qualified, designated people are assigned the responsibilities that are required to safely and properly signal the components into place. The system should specify what methods and tools will be used (that is, hand signals, radios, etc.) to perform this task.

7.7.7 Operator Training and Certification

Today's modern cranes are highly engineered, technically advanced machines that require thoroughly trained and competent operators to ensure safe use. It is imperative that operators are trained and tested on the specific type of crane used. Operator certification through an accredited crane/derrick operator testing organization is suggested. Specific state legislation requires the use of a certified crane operator (CCO) licensed crane operator. Check with your state regulations to determine if there are specific crane operator training requirements.

7.7.8 Ground Pressures and Travel Paths

Many crane incidents are due to inadequate bearing surfaces. Whether you are hoisting a load or simply walking the crane, bearing pressures and ground surface capabilities should be determined for each activity. During all major component lifts, crane mats should be placed on top of the crane pad.

7.7.9 Crane Travel Limits

All cranes should have a published chart indicating the travel guidelines for "walking" or "traveling" the crane. Considerations for the maximum percent grade, side slope, and boom position should be accounted for when planning the roadways and especially when traveling the crane. In addition, all overhead and underground obstacles should be discussed and marked for safe crane travel.

7.7.10 Control of the Lift Area

Once you are ready to make a lift, a safe zone for all non-essential personnel should be established. Essential personnel operations should be planned and supervised so that no one is working under the boom or lifted component.

7.7.11 Lift Plans

Lift plans should be provided for each major component lift to the crane operator prior to performing the work. The operator should keep the lift plans on hand to ensure that each lift falls within the plans made. Lift plans should have basic information such as crane configuration, component weights, rigging requirements and weights, crane capacities, crane pad requirements, and so forth. The more information that can be provided to the operator, the safer the work site will be.

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Appendix A: Listing of Key Points

A.1 Key O&M Cost Points

Key O&M Cost Point
Emphasizes information that will result in overall reduced costs and/or an increase in revenue through additional or restored energy production.

Section Number	Page Number	Key Point
1.6.3	1-9	When purchasing a fleet of wind turbines, it is not uncommon that a given subcomponent (for example, pitch drive, gear drive, bearings, generator bearings, etc.) will be furnished by different manufacturers. Consequently, it is possible that no two wind turbines will be identical. This can directly affect the scope and frequency of maintenance activities (for example, different gearboxes may use different types of grease).
1.6.3	1-9	When purchasing a fleet of wind turbines that do not all have the same exact subcomponents, it is beneficial to request a subcomponent list (bill of material) for each wind turbine in order to optimize maintenance activities.
1.6.3	1-10	Turnover of wind turbines after commissioning should be staggered so that the entire fleet is not turned over at the same time. Individual wind turbine commissioning turnover causes the owner to do 30-day maintenance activities all at once in order to remain in warranty, which puts unnecessary scheduling and staffing demands on the owner when scheduling/optimizing planned maintenance activities.

Section Number	Page Number	Key Point
1.6.3	1-11	Care should be taken when procuring maintenance kits from the original wind turbine manufacture because not everything typically included in a kit will be needed (for example, brake pads).
5.1	5-2	As a general rule of thumb, if the repair costs are 50% or less of the replacement cost, then repair should be considered. If the percentage is greater, then replacement is generally the best option.

A.2 Key Technical Points

Key Technical Point
Brake adjustment is a critical activity that should be integral to and performed during commissioning.

Section Number	Page Number	Key Point
1.6.2	1-8	Off-site power is needed in order to start generation of electricity. A wind turbine cannot start generating electricity as soon as the wind starts blowing.
1.6.2	1-8	Extreme care should be taken when de-energizing a wind turbine because computer hard drive failures may occur.
1.6.3	1-10	Brake adjustment is a critical activity that should be integral to and performed during commissioning.
1.6.3	1-11	Specialty tools used for greasing and torquing typically have long lead times for delivery. This should be considered during initial procurement and maintenance planning and might need to be factored in to the site's tool calibration and rotational use program.
1.6.3	1-11	Portable electric generators might be needed when there is a loss of on-site power to perform regularly scheduled maintenance activities.

Section Number	Page Number	Key Point
3.3	3-11	EPRI worked with the DOE and several EPRI member to help establish methods of tracking wind turbine performance: 1. Fort Davis; in Fort Davis, Texas, owned by American Electric Power (AEP) 2. Springview; Keya Paha County, Nebraska, owned by Nebraska Public Power District (NPPD) 3. Searsburg; Searsburg, Vermont, owned by Green Mountain Power (GMP) 4. Glenmore; Glenmore, Wisconsin, owned by Wisconsin Public Service (WPS) 5. Algona; Algona Municipal Utilities in Algona, Iowa 6. Kotzebue; Kotzebue, Alaska, owned by Kotzebue Electric Association, Inc.
4.1.1.1	4-2	Predictive maintenance tasks are performed based on equipment condition. Predictive maintenance relies on technologies to determine the current condition of the equipment so that only the required maintenance is performed before equipment failure.
4.1.1.2	4-2	Periodic maintenance consists of "time-based" preventive maintenance actions taken to maintain a piece of equipment within design operating conditions and to extend its life.
4.1.2	4-2	Corrective maintenance tasks are generated as a result of equipment failure. Corrective tasks are generated when equipment is purposely operated to failure and also when equipment failure is not wanted or planned. It is the most basic form of maintenance and also the most expensive. Most plants are moving away from corrective maintenance but there will always be a portion of maintenance that is performed as a result of equipment failure.
4.3.1	4-5	Typically, after the initial warranty period is over, sound wave attenuation testing (vibration monitoring) and borescopic inspections should be considered to detect abnormal or accelerated wear of gearbox components.

Section Number	Page Number	Key Point
4.3.2.1	4-10	The most important facet of a preventive maintenance program for a gearbox is the regular inspecting, analyzing, and changing of the lubricant.
4.3.2.1	4-10	Gearbox oil should typically be sampled every six months. Filters should be changed every year. Gearbox oil should be changed every two years, but some wind turbine manufacturers recommend changing the oil on a three-year cycle.
4.3.2.1	4-12	Trending contaminant concentrations is important because it provides an indication of significant increases over time. In some cases, an increase of only 10 ppm of iron is significant because iron contamination indicates contamination from gear wear particles.
4.4.2.1	4-18	Generator brushes should typically be replaced every three years.
4.7	4-37	Initial maintenance of the wind turbine should include retorquing the bolts.
4.10	4-44	Initial lubing of the blades, yaw bearing, and pitch bearing should be done immediately after construction.
4.10	4-45	Pitch bearing lubrication should typically be performed every six months. Initially, however, many are not lubricated properly, and after six to eight months of use, some damage may occur. The initial procedure for greasing these bearings should be detailed to include the appropriate amount of grease and the type of grease.
5.3.1.5	5-7	It is advisable to pour a small amount of oil on each bearing or journal surface to ensure that an oil film is present whenever manually rolling the gear because the lubrication system is inoperable.
5.3.3.6	5-12	Before replacing a wiped bearing, determine and correct the cause of the wipe.

A.3 Key Human Performance Points

Key Human Performance Point
Denotes information that requires personnel action or consideration in order to prevent personal injury, prevent equipment damage, and/or improve the efficiency and effectiveness of the task.

Referenced Section	Page Number	Key Point
1.6.2	1-8	Owners of wind turbine facilities should estimate having approximately one full-time technician for every seven to eight wind turbines in their fleet.
7.5	7-7	Permits should be required to control the number of people entering confined spaces. Typically, due to high CO content (if batteries have failed), the number of personnel entering a confined space should be limited to four.

A.4 Key Supervisory Observation Points

Key Supervisory Observation Point
Identifies tasks or series of tasks that can or should be observed by maintenance first line supervisors to improve the performance of the maintenance staff and improve the reliability of the component.

Referenced Section	Page Number	Key Point
1.6.3	1-10	During the commissioning of a fleet of wind turbines, care should be taken to ensure that the commission teams are performing activities consistently and accurately and that quality control personnel are providing oversight **in** the towers as the teams are performing commissioning activities.

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