ELECTRIC POWER
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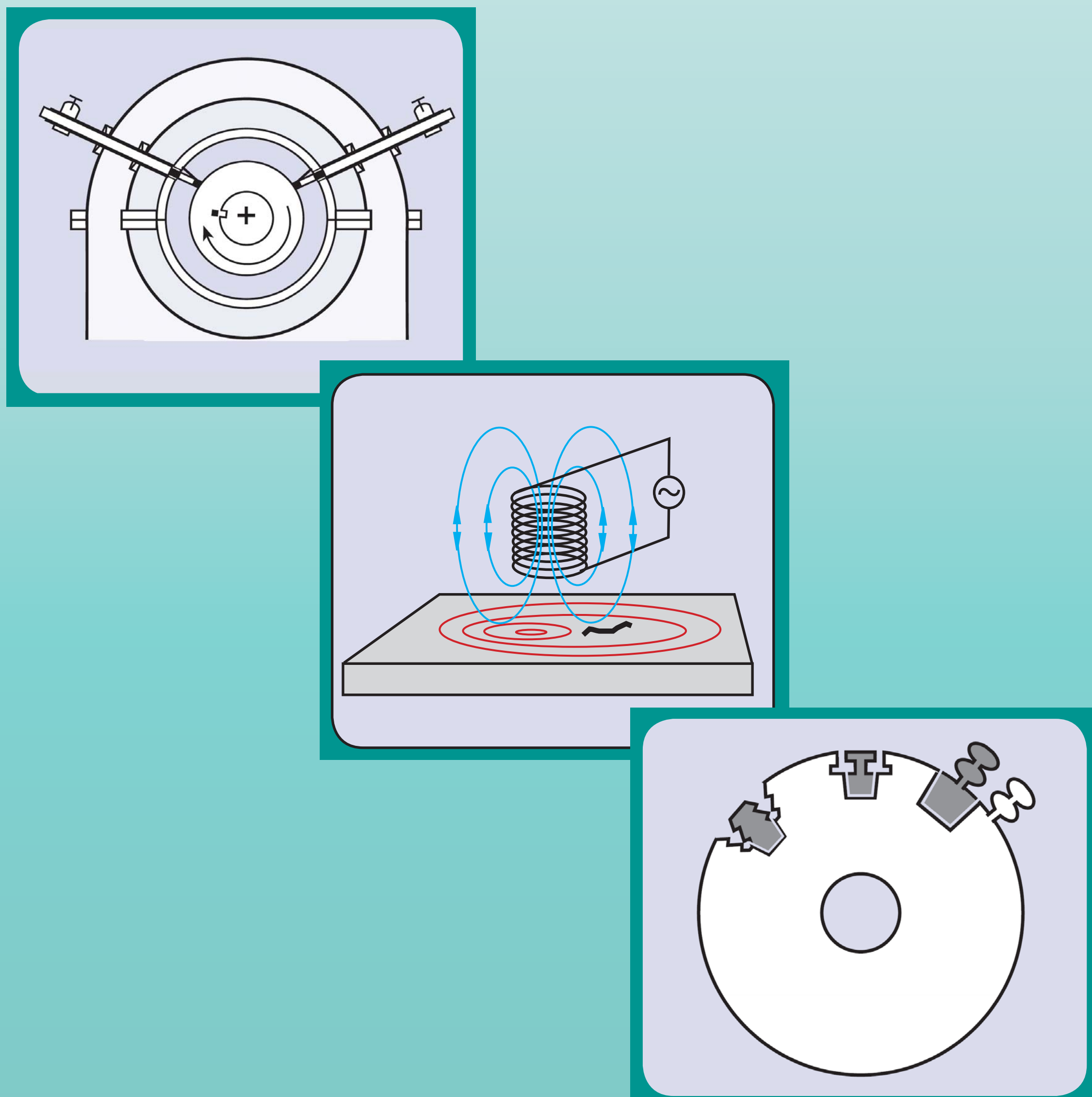
Steam Turbine Monitoring, Inspection) and Repair



Introduction

Turbine component degradation and failure continues to result in significant economic impact and turbine unavailability at both nuclear and fossil power generating plants. It is therefore to every operator's advantage to have a formalized program for correction, prevention, and control of steam path damage. Three key pieces of such a program are monitoring and diagnostics, inspection and nondestructive evaluation (NDE), and turbine repair. This brief document summarizes the latest procedures and resources in these three technical areas. The information covers material of importance for those owners performing their own diagnostics and repairs, and should provide an overview to aid those working with outside vendors and OEMs to better understand the available options and procedures, allowing them to make the most effective and economical choices for maintaining the health of turbine equipment.

1. Monitoring and Diagnostics

1.1 Condition Monitoring

Supervisory instrument monitors indicate the condition and trend of rotating and stationary components, and can provide advance warning of deterioration or change in the turbine-generator condition. Typically measured parameters are:

- Rotor axial position.
- Differential rotor thermal expansion and cylinder expansions. Instrumentation can provide differential measurement of movement or expansion of cylinders and rotors relative to one another or to their support structure, helping avoid rubs.
- Bearing vibrations. Detection of a change in the amplitude and phase angle of bearing vibrations can indicate loss of a blade,and help avoid radial rubs or seal leakage.
- Shaft eccentricity. Provides peak-to-peak radial motion of rotor to non-rotating parts.
- Shaft speed.
- Steam valve positions.
- Metal temperature measurements. Measuring points typically include walls of the HP and interceptor steam valve chests, and in the HP and IP cylinders.
- Thrust bearing temperature. High thrust bearing temperatures can indicate rubbing or damage by water induction.
- Thrust bearing wear can provide an indication of water induction or blade deposits.
- Condenser backpressure. At low load, high backpressure should trip the turbine to avoid conditions such as flutter in last stage blades, overheating by windage, or recirculation which can lead to high vibratory stresses.

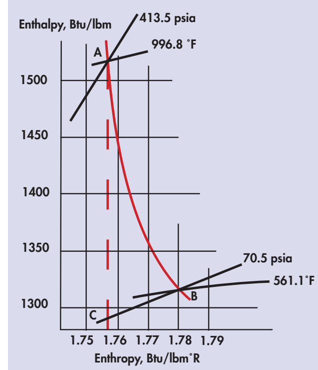
Although not widely used, blade vibration monitors are recommended for units with known vibration problems in order to confirm the root cause of damage and assess the efficiency of modifications. Two approaches to blade vibration monitoring are:

- Strain gauges attached to rotating blades can transmit data via radio telemetry. This method is well proven, but has the disadvantage that the strain gages have a fairly short life, and re-installation requires opening the turbine.
- Magnetic, optical or eddy current sensors inserted through guide tubes in the casing measure blade passing time of arrival. If the blade is vibrating non-synchronously, then the blade tip will arrive earlier or later than expected. Minimum detectable vibration deflection ranges from 10 μm to 25 μm.

1.2 Performance Monitoring

In addition to condition monitoring with supervisory instrumentation, performance testing can yield critical information about unit health.

- Enthalpy drop efficiency testing in superheated steam sections is straightforward, requiring accurate measurements of inlet and exhaust steam temperature and pressure, as illustrated in Figure 1-1. Enthalpy drops in turbine sections containing two phases require measurement of moisture level, which has only recently become available on a routine basis. Optical probes use light scattering to determine the percentage decrease in light intensity and thus derive the size of suspended droplets in the steam. Liquid mass flow rates derived from droplet sizes can be used to determine wetness.
- Simplified heat rate testing consists of measuring the heat supplied to the turbine cycle and the electrical output at given valve points. It also requires flow measurements, cycle isolation, and measurement of certain feedwater temperatures and pressures.
- Capability testing includes measurements of electric output at specific governing valve points, extraction flows, pressures and temperatures.
- Steam rate testing requires accurate measurement of throttle steam flow, generator output at given valve points, extraction steam flow rates, steam pressures and temperatures.



Intermediate Pressure Turbine Enthalpy Drop

Location	Press., psia	Temp., °F	Enthalpy Btu/lbm	Entropy Btu/lbm°R
(A) IP inlet	413.5	996.8	1521.1	1.758
(B) IP EXH	70.5	561.1	1312.4	
(C) Isentropic	70.5	. . . .	1290.5	1.758

Isentropic enthalpy drop= 1521.1-1290.5 = 230.6 Btu/lbm
Actual enthalpy drop = 1521.1-1312.4 = 208.7 Btu/lbm
Stage group efficiency = (208.7/230.6)100% = 90.5%

Figure 1-1. Determining stage group efficiency by the enthalpy drop method.[3]

- Heat balance testing requires precise measures of all steam flows, temperatures, pressures, and electrical output.
- One additional simple screening measure is to compare stage inlet steam pressure and flow or feedwater flow. Figure 1-2 can be used as a simple means to detect performance degradation.

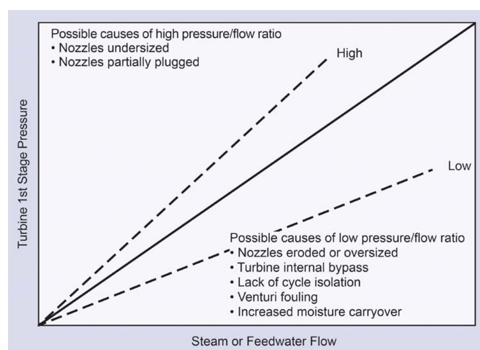


Figure 1-2. Degradation as indicated by plotting turbine first stage pressure versus flow rate.[1]

2. Inspection and Nondestructive Evaluation

2.1 Visual Examination

Visual inspection is one of the most basic and important means of damage evaluations. The results should be used to determine whether additional disassembly will be needed and whether more thorough NDE is indicated by a survey or inspection of the easily accessible locations.

Typical forms of damage that can be assessed with visual examination include:

- Missing blades or covers.
- General surface condition of blades, shields, etc.
- General surface condition of coatings.
- Degree of erosion by solid particles or liquid droplet impingement.
- Visible signs of cracking.
- Surface damage including pitting, corrosion buildup, deposits, foreign object damage.
- Heavy rubbing.
- Notch lifting.
- Evidence of elongation such as by creep or other gross deformation.
- Distortion.
- Forging laps.

Key locations to be accessed include: the first stage of the HP and IP (primarily for assessing accumulating damage by solid particle erosion and copper deposition) and the last few rows of the LP turbine, for erosion, fatigue and corrosion fatigue.

Most of these damage types are also detectable by fiber optics devices through manway, access ports, fittings, extraction cavities, or other penetrations through the casing. (Figure 2-1 and 2-2)

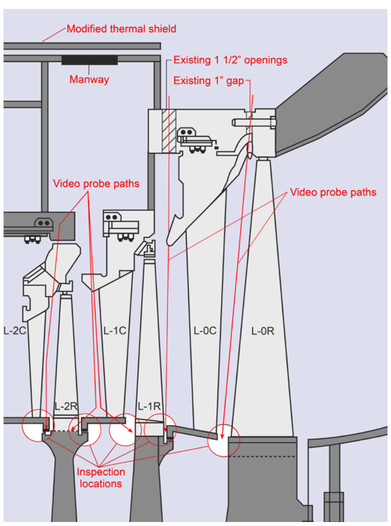


Figure 2-1. Example of visual in-situ inspection of L-0, L-1, and L-2 rows.[1]

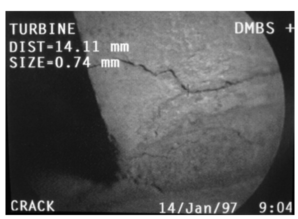
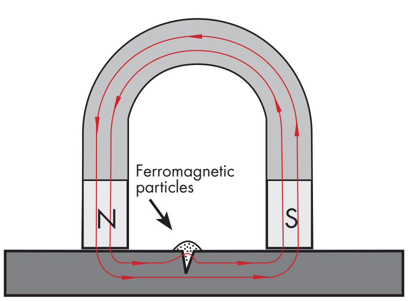


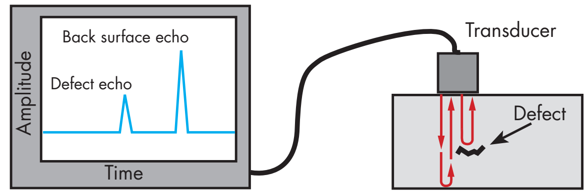
Figure 2-2. Crack in LP blade as seen through fiberscope inspection.[1]

2.2 NDE Methods[2]

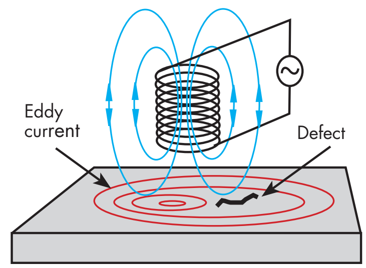
- Penetrant Testing: Liquid penetrants are applied and seep into various types of minute surface openings by capillary action, making them evident by inspection. The major limitation of liquid penetrant inspection is that it cannot detect subsurface flaws. Another factor that can limit the use of liquid penetrants is surface roughness or porosity. Such surfaces produce excessive background and interfere with inspection.
- Magnetic Particle Testing: When the material or part under test is magnetized, magnetic discontinuities that lie in a direction generally transverse to the direction of the magnetic field will cause a leakage field to be formed at and above the surface of the part. The presence of this leakage field, and therefore the presence of the discontinuity, is detected by the use of finely divided ferromagnetic particles applied over the surface, with some of the particles being gathered and held by the leakage field. Nonferromagnetic materials cannot be inspected by magnetic particle inspection.



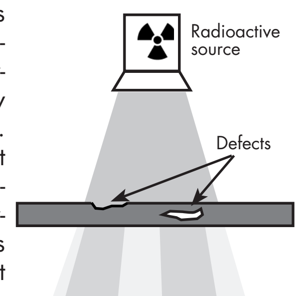
- Ultrasonic Testing (UT): Beams of high frequency (0.1 and 25 MHz) sound waves are introduced into the material to be inspected. The sound waves reflect at interfaces, such as cracks, inclusions and other defects, yielding information about the size and location of flaws. UT inspection is one of the most widely used and effective NDE methods, but requires extensive technical expertise.



- Eddy Current Testing: One or more induction coils are used to induce eddy currents in a part, the pattern of which will be affected by the presence of a flaw or crack. The eddy currents create their own electromagnetic field, which can be sensed either through the effects of the field on the primary exciting coil or by means of an independent sensor. Eddy current inspection is extremely versatile, which is both an advantage and a disadvantage - some variables in a material that are not important in terms of material or part serviceability may cause instrument signals that mask critical variables or are mistakenly interpreted to be caused by critical variables.



- Radiography Testing: Radiography is used to detect the features of a component or assembly that exhibit a difference in thickness or physical density as compared to surrounding material. In general, radiography can detect only those features that have an appreciable thickness in a direction parallel to the radiation beam. This means that the ability of the process to detect planar discontinuities such as cracks depends on proper orientation of the testpiece during inspection.



3. Turbine Repair Methods

3.1 Blade Repair

- For extensive blading damage, it may be economically advantageous to replace blades. For shrouded blades, this is accomplished by cutting the shroud on each side, removing the blade, installing a new blade and butt welding the shroud.
- Erosion Shield Repair
  a. Repair by welding: Welding provides a better attachment than brazing, but it has been traditionally recommended that the blade be removed and factory welded so that the proper heat treatment can be performed. In-situ repair by welding is an option if erosion is not too severe.
  b. Repair by brazing: Brazing is easier to apply in-situ than welding, but generally results in a weaker bond. Cracks in the brazed interface of shielding should be repaired by rebrazing.

c. Local hardening: If damage is not severe, flame or laser hardening can be used to increase erosion resistance of existing blade or shield material locally.

d. Changing leading blade: Where liquid droplet erosion is significantly greater on the leading blades of blade groups, the lashing lug can be cut on the leading blade and the lugs welded to the trailing blade of the next group. This rotates which blade is the leading blade.

- Tenon and Coverband Repair: Light damage to tenons and coverbands can be repaired in-situ without removing blades or coverbands and with the rotor in place. Moderate to heavy damage requires removal of blades and coverbands, weld rebuild of tennons and reinstallation of new or repaired coverband.
- Tiewire Repair:

a. Full penetration weld repairs. Breaks can be repaired using a full penetration weld. Type 410 stainless steel filler material is deposited into a half round copper chill.

b. Split sleeve repair. A stainless steel split sleeve can be soldered over a tiewire break.

c. Plug insertion. Weld repairs are typically not practical for hollow tiewires. Instead, a plug can be inserted into hollow tiewires at the end of the wire and driven along until it spans the break. The plug is then silver brazed in place.

d. Redesign of blade. With modern analysis tools, it is possible to develop designs in which the tiewires can be eliminated and this should be considered for conditions where there are significant problems in the tiewire area of the blade.

- Airfoil Repair: Minor pitting can be removed by light abrasion. Erosion damage, if extensive will need repair; if it is less extensive it should be blended out or left. Blending will result in improved aerodynamics and thus lower losses, however, in the early stages after blending, may result in slightly faster erosion rates. Cracked blades may require replacement. Repair of cracking in an airfoil at the tiewire hole can be done either in-situ or in shop.
- Blade Root Repair: At this time, repair to the roots of rotating blades is not recommended because of the large stresses inherent in these attachment areas.
- Stationary Blade Repair: Welding and grinding of stationary blades/nozzles can restore base metal to the original contour, although typically this does not enhance the resistance to erosion. Following welding, grinding to reestablish nozzle contour and throat area is required. This is followed by a procedure such as glass bead cleaning to improve the surface finish.

3.2 Disk Repair

Weld repairs of rotors are a major undertaking. Seven classes of rotor repairs have been defined, as illustrated by Figure 3-1.

Weld metals are typically chosen to match the composition of the rotor, with modifications to improve properties or SCC resistance. Gas tungsten arc welding (GTAW) and submerged arc welding (SAW) have been most commonly used for repairs, although gas metal arc welding (GMAW) and shielded metal arc welding (SMAW) have also been used. Both pre-and postweld heat treatments must be carefully chosen and qualified as part of the overall repair qualification. Multiple inspections should be performed to monitor the repair process.

4. References

1. *Turbine Steam Path Damage: Theory and Practice, Volumes 1*. EPRI, Palo Alto, CA: . 666. TR-108943.
2. ASM International Handbook Committee (1989), ASM Handbook, Volume 17 – Nondestructive Evaluation and Quality Control, ASM International
3. American Society of Mechanical Engineers, Procedures for Routine Performance Tests on Steam Turbines, ASME PTC-6S Report -1988 Reaffirmed 1995, American Society of Mechanical Engineers, New York, NY, 1989

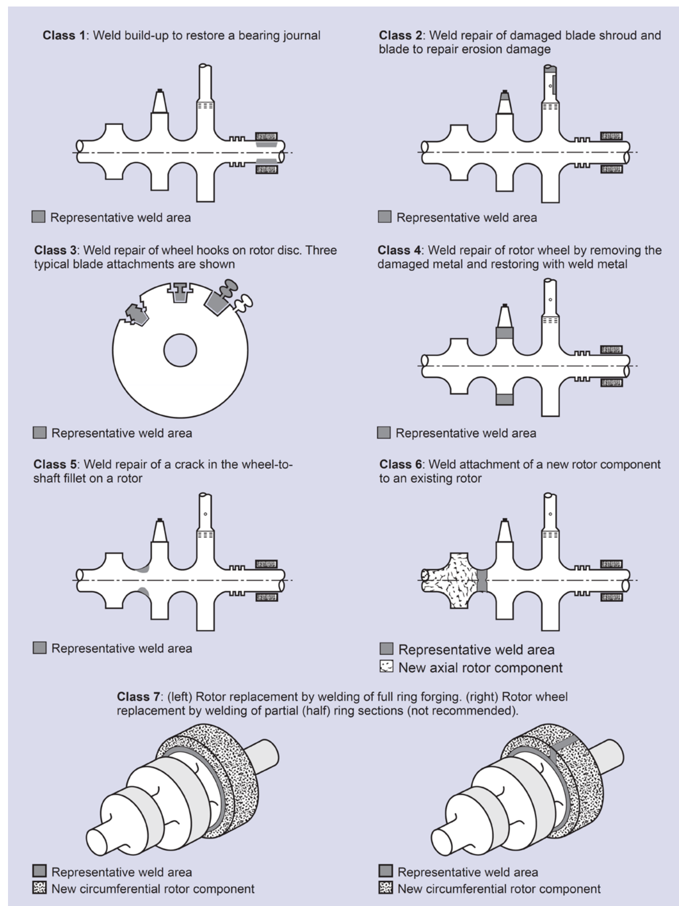


Figure 3-1. Seven classes of rotor repairs.[1]

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