STEAM TURBINE CORROSION AND DEPOSITS PROBLEMS AND SOLUTIONS

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ABSTRACT

This tutorial paper discusses the basics of corrosion, steam and deposit chemistry, and turbine and steam cycle design and operation—as they relate to steam turbine problems and problem solutions.

Major steam turbine problems, such as stress corrosion cracking of rotors and discs, corrosion fatigue of blades, pitting, and flow accelerated corrosion are analyzed, and their root causes and solutions discussed. Also covered are: life prediction, inspection, and turbine monitoring. Case histories are described for utility and industrial turbines, with descriptions of root causes and engineering solutions.

INTRODUCTION

This tutorial paper discusses steam turbine corrosion and deposition problems, their root causes, and solutions. It also reviews design and operation, materials, and steam and deposit chemistry. References are provided at the end of the paper.

With an increase of generating capacity and pressure of individual utility units in the 1960s and 70s, the importance of large steam turbine reliability and efficiency increased. The associated turbine size increase and design changes (i.e., larger rotors and discs and longer blades) resulted in increased stresses and vibration problems and in the use of higher strength materials (Scegljajev, 1983; McCloskey, 2002; Sanders, 2001). Unacceptable failure rates of mostly blades and discs resulted in initiation of numerous projects to investigate the root causes of the problems (McCloskey, 2002; Sanders, 2001; Cotton, 1993; Jonas, 1977, 1985a, 1985c, 1987; EPRI, 1981, 1983, 1995, 1997d, 1998a, 2000a, 2000b, 2001, 2002b, 2002c; Jonas and Dooley, 1996, 1997; ASME, 1982, 1989; Speidel and Atrens, 1984; Atrens, et al., 1984). Some of these problems persist today. Cost of corrosion studies (EPRI, 2001a, Syrett, et al., 2002; Syrett and Gorman, 2003) and statistics (EPRI, 1985b, 1997d; NERC, 2002) determined that amelioration of turbine corrosion is urgently needed. Same problems exist in smaller industrial turbines and the same solutions apply (Scegljajev, 1983; McCloskey, 2002; Sanders, 2001; Cotton, 1993; Jonas, 1985a, 1987; EPRI, 1987a, 1998a; Jonas and Dooley, 1997). The corrosion mechanisms active in turbines (stress corrosion cracking, corrosion fatigue, pitting, flow-accelerated corrosion) are shown in Figure 1.

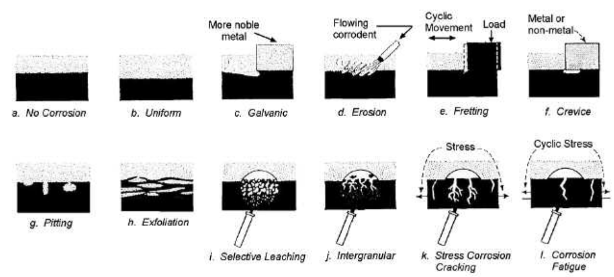

Figure 1. Corrosion Mechanisms Active in Steam Turbines.

Purpose, Design, and Operation of Steam Turbines

The steam turbine is the simplest and most efficient engine for converting large amounts of heat energy into mechanical work. As the steam expands, it acquires high velocity and exerts force on the turbine blades. Turbines range in size from a few kilowatts for one stage units to 1300 MW for multiple-stage multiple-component units comprising high-pressure, intermediate-pressure, and up to three low-pressure turbines. For mechanical drives, single- and double-stage turbines are generally used. Most larger modern turbines are multiple-stage axial flow units. Figure 2 shows a typical tandem-compound turbine with a combined high pressure (HP), intermediate pressure (IP) turbine, and a two-flow low-pressure (LP) turbine. Table 1 (EPRI, 1998a) provides alternate terminology for several turbine components.

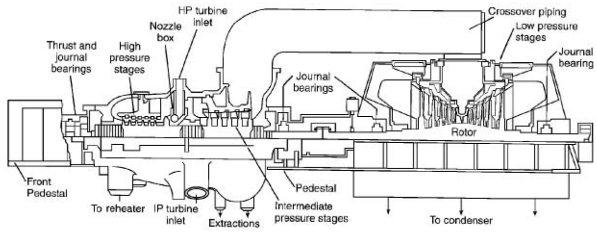

Figure 2. Typical Tandem Compound, Single Reheat, Condensing Turbine. (Courtesy of EPRI, 1998a)

Table 1. Alternate Terminology for Turbine Components.

Common Term	Alternative Terms
Rotating Blades and Parts	
Rotating blades	Buckets
Blade root	Serrations, attachments, fir trees, hooks, attachment base
Blade base	Platform
Blade airfoil	Vane, partition, foil
Pin and finger root	Pinned finger, fork-shaped fastening
Fir-tree (attachment)	Dovetail
Pins	Prongs
Tiewires	Lacing wires, lashing wires, arch bands, snubber, connectors
Shrouds	Covers, bands, coverbands, integral shrouds, spill strips
Tuned blade packets	Harmonic shrouding
Tenons	Rivets, pegs
Tenon rivet	Tenon upset, tenon head
Countersunk tenon rivet	Foxholed tenon
Dovetail	Steeple, roots and grooves
Blade group	Blade packet
Closing blade	Notch piece/blade
Stationary Blades and Parts	
Stationary blades	Nozzles
Nozzle chests	Nozzle boxes, nozzle plate, nozzle chamber/block
Diaphragms	Partitions, blade ring/carrier, stationeries, rings
Stationary vanes	Nozzle foils, nozzle vanes, nozzle partitions
Other Components	
Inlet	Bowel
Control stage	First stage, governing stage, partial admission stage, inlet stage
Rotor	Shaft, wheel, spindle
Disc	Wheel
Keyways of discs	Anti-rotation pin slots
Disc-rim blade attachment	Steeple
Blade entry slot	Gate, notch
Seal	Sealing labyrinth, labyrinth seal, sealing fin, packing ring, packing, gland, sealing strip, spill strip
Turning gear	Barring gear
Pedestal	Standard
Turbine section	Cylinder
Exhaust hood	Exhaust port
Turbine casing	Shell, cylinder
Sleeve rings	Snout rings, piston rings, inlet rings
Attemperators	Sprays

Steam enters from the main steam lines through stop and control valves into the HP section. The first (control) stage is spaced slightly apart from subsequent stages to allow for stabilization of the flow. After passing through the HP turbine, cold reheat piping carries the steam to the reheater (if present) and returns in the hot reheat piping to the integrated HP and IP cylinder to pass through the IP turbine section. The flow exits the IP turbine through the IP exhaust hood and then passes through crossover piping to the LP turbine and exits to the condenser through the LP exhaust. The typical modern steam turbine has a number of extraction points throughout all sections where the steam is used to supply heat to the feedwater heaters.

During its expansion through the LP turbine, the steam crosses the saturation line. The region where condensation begins, termed the phase transition zone (PTZ) or Wilson line (Cotton, 1993; EPRI, 1997c, 1998a, 2001b), is the location where corrosion damage has been observed. In single reheat turbines at full load, this zone is usually at the L-1 stage, which is also in the transonic flow region where, at the sonic velocity (Mach = 1), sonic shock waves can be a source of blade excitation and cyclic stresses causing fatigue or corrosion fatigue (EPRI, 1997c; Jonas, 1994, 1997; Stastny, et al., 1997; Petr, et al., 1997).

Design

Because of their long design life, steam turbines go through limited prototype testing where the long-term effects of material degradation, such as corrosion, creep, and low-cycle fatigue, cannot be fully simulated. In the past, when development was slow, relatively long-term experience was transferred into new products. With new turbine types, larger sizes, new power cycles, and water treatment practices coming fast in the last 25 years, experience was short and limited, and problems developed, which need to be corrected and considered in new designs and redesigns. While the turbine seems to be a simple machine, its design, including design against corrosion, is complex.

There are five areas of design that affect turbine corrosion:

- Mechanical design (stresses, vibration, stress concentrations, stress intensity factor, frictional damping, benefits of overspeed and heater box testing)
- Physical shape (stress concentration, crevices, obstacles to flow, surface finish, crevices)
- Material selection (maximum yield strength, corrosion properties, material damping, galvanic effects, etc.)
- Flow and thermodynamics (flow excitation of blades, incidence angle, boundary layer, condensation and moisture, velocity, location of the salt zone, stagnation temperature, interaction of shock wave with condensation)
- Heat transfer (surface temperature, evaporation of moisture, expansion versus stress, heated crevices)

Recognition of these effects led to a formulation of rudimentary design rules. While the mechanical design is well advanced and the material behavior is understood, the flow excitation of blades and the effects of flow and heat transfer on chemical impurities at surfaces are not fully included in design practices.

Selection of some combinations of these design parameters can lead to undesirable stresses and impurity concentrations that stimulate corrosion. In addition, some combinations of dissimilar materials in contact can produce galvanic corrosion.

Design and material improvements and considerations that reduce turbine corrosion include:

- Welded rotors, large integral rotors, and discs without keyways—eliminates high stresses in disc keyways.
- Replacement of higher strength NiCrMoV discs with lower (yield strength < 130 ksi (896 MPa) strength discs.
- Repair welding of discs and rotors; also with 12%Cr stainless steel weld metal.
- Mixed tuned blade rows to reduce random excitation.
- Freestanding and integrally shrouded LP blades without tenon crevices and with lower stresses.
- Titanium LP blades—corrosion resistant in turbine environments except for NaOH.
- Lower stress and stress concentrations—increasing resistance to SCC and CF.
- Flow path design using computerized flow dynamics and viscous flow—lower flow induced vibration, which reduces susceptibility to CF.
- Curved (banana) stationary blades that reduce nozzle passing excitation.
- New materials for blade pins and bolting—resistant against SCC.
- Flow guides and double-ply expansion bellows—reduces impurity concentration, better SCC resistance.
- Moisture extraction to improve efficiency and reduce flow-accelerated corrosion (FAC) and water droplet erosion and use of alloy steels to reduce FAC.

LP Rotor and Discs

There are three types of construction in use for LP rotors:

- Built-up (shrunk-on design) with forged shaft onto which discs are shrunk and keyed,

- Machined from one solid piece (most common), or
- The discs welded together to form the rotor (Figure 3).

The rotor and disc construction is governed by the practices of individual manufacturers, capabilities of steel mills, cost, and, during the last few decades, by their resistance to SCC. The solid and welded rotors do not have a problem with disc bore SCC. The three types, shown in Figure 3, have little effect on the SCC and CF susceptibilities of the blade attachments.

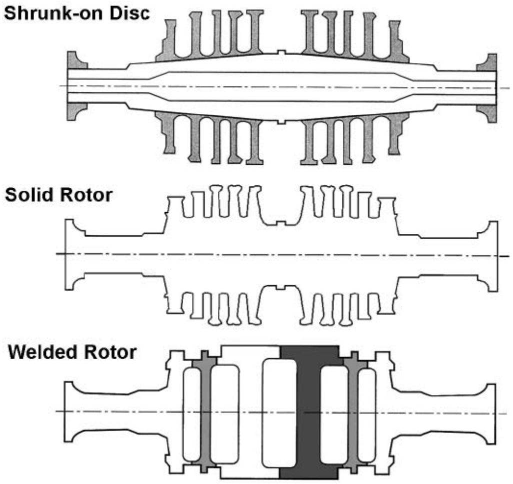

Figure 3. Three Types of Rotor Construction. (Courtesy of EPRI, 1998a)

LP Blades

Blade and blade path design and material selection influence blade CF, SCC, pitting, and other forms of damage in many ways (Sanders, 2001; EPRI, 1981, 1997c, 1998a, 2001b; *BLADE-ST*™, 2000). The main effects of the blade design on corrosion, corrosion fatigue strength, stress corrosion cracking susceptibility, and pitting resistance include:

- Vibratory stresses and their frequencies.
- Maximum service steady stresses and stress concentrations.
- Flow induced vibration and deposition.
- Mechanical, frictional, and aerodynamic damping.

Rotating LP turbine blades may be "free standing" (not connected to each other), connected in groups, or all blades in the row may be "continuously" connected by a shroud. Connections made at the blade tip are termed shrouds or shrouding. Shrouds may be inserted over tenons protruding above the blade tips and these tenons then riveted down to secure the shrouds, or they may consist of integrally forged or machined stubs, which, during operation, provide frictional damping of vibration because they touch (Figure 4). This design also eliminates the tenon-shroud crevices where corrosive impurities could concentrate. In some cases, long 180 degree shrouds are used or smaller shroud segments are welded together.

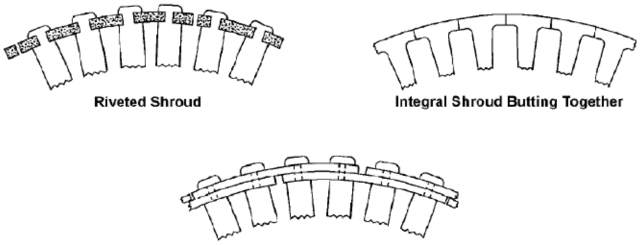

Figure 4. Typical Turbine Shrouds. (Courtesy of EPRI, 1998a)

Blades are connected at the root to the rotor discs by several configurations (Figure 5). There are several types of serrated attachments: the fir tree configuration, which is inserted into individual axial slots in the disc; and the T-shape, which is inserted into a continuous circumferential slot in the disc. The "finger" type attachment is fitted into circumferential slots in the disc and secured by axially inserted pins. All of the blade root designs have geometries that result in higher local stresses at radii and stress concentrations that promote SCC and CF. The goal of the design should be to minimize these local tensile stresses.

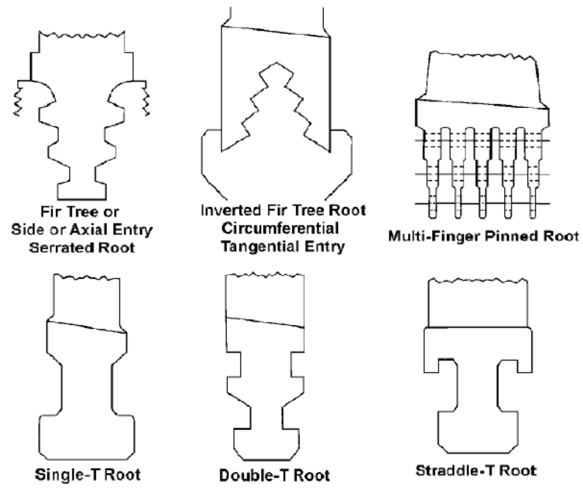

Figure 5. Types of Blade Root Attachments. (Courtesy of EPRI, 1998a)

The airfoil of blades may be of constant cross-section for short blades, and twisted for longer ones. The longest blades for the last few rows of the LP are twisted to match the aerodynamics at different radii and improve aerodynamic efficiency. The longer blades are usually connected at the point of highest vibration amplitude to each other by a tie or lashing wire, which reduces vibration of the airfoil. To reduce random excitation, mixed tuning of long rotating blades has been used in which adjacent blades have different resonant frequencies (EPRI, 1998a).

Stationary blades in LP stages are typically arranged in diaphragms of cast or welded construction. In wet stages, diaphragms may be made with hollow blade vanes or other design features as a means of drawing off moisture that would otherwise lead to liquid droplet erosion (EPRI, 2001b). Recently, some stationary blade designs have also been leaned or bowed, improving flow and efficiency and lowering the excitation forces on the downstream rotating blades.

Casings

Turbine casings must contain the steam pressure and maintain support and alignment for the internal stationary components. They are designed to withstand temperatures and pressures up to the maximum steam conditions. Their design has evolved over the years and casings are now multiple pressure vessels (for example, an inner and outer casing in the HP and IP cylinder, or a triple casing) allowing smaller pressure drops and thinner wall thickness. These thinner cross-sections allow for a lower temperature gradient across the casing section and thus lower thermal stresses. The LP casing may also be a multiple part design with the inner casing containing the supports for the diaphragms and the outer casing directing the exhaust to the condensers.

Design Recommendations for Corrosion Control

New designs, redesigns, and failed components should be checked to determine if they meet allowable corrosion-related design specifications and other corrosion related requirements (Jonas, 1985c).

In new designs and redesigns of turbine components, use should be made of the new design tools, including 3D finite element stress and vibration analysis and 3D viscous flow analysis, and consideration of condensation and impurity behavior. Blade resonance frequencies should be verified by telemetry. To ensure a corrosion-free design, a corrosion engineer and a chemist should be consulted during the design activity.

The following should be considered in design of steam turbines:

- *Stresses* (Jonas, 1985c)—The mechanical design concepts for avoidance of SCC and CF should include an evaluation of the material corrosion properties and defects that influence susceptibility to SCC and CF, i.e., threshold stress (σ_{SCC}), threshold stress intensity (K_{ISCC} and ΔK_{thCF}), crack growth rate ($(da/dt)_{SCC}$ and $(da/dN)_{CF}$), corrosion fatigue limit, pitting rate, and pit depth limit. True residual stresses (micro and macro) should also be considered. Because SCC and CF initiate at surfaces, the maximum surface stresses must be controlled, usually by control of the elastic stress concentration factor, k_t. The stresses should be the lowest in the "salt zone" region where corrosion is most likely.

- Vibratory stresses are rarely accurately known, except when telemetry on operating turbines is performed. The design approach should be to minimize flow excitation, tune the blades, provide maximum damping, and perform laboratory and shop stationary frequency testing. Heater box overspeed and overspeed testing during operation are generally beneficial in reducing operating stresses by local plastic deformation.

- *Heat transfer and flow* (EPRI, 1997c)—Surface temperature resulting from heat transfer and flow stagnation should be considered along with its effect on thermodynamic conditions of the impurities and water film at surfaces (i.e., evaporation of moisture). Flow effects on blade vibration and deposit formation are complex, and there are over 15 flow blade excitation mechanisms to be considered.

- *Flow of moisture*—To avoid flow-accelerated corrosion (EPRI, 1996; Kleitz, 1994; Jonas, 1985b; Svoboda and Faber, 1984) and water droplet erosion (Ryzenkov, 2000; Pryakhin, et al., 1984; Rezinskikh, et al., 1993; Sakamoto, et al., 1992; Povarov, et al., 1985; Heyman, 1970, 1979, 1992), the flow velocity of wet steam should not exceed the allowable velocity specific to the materials and moisture chemistry. Regions of high turbulence should be avoided or higher chromium steels should be used. Blade path moisture can be extracted.

- *Crevices*—Crevices can act as impurity traps and concentrators, facilitate formation of oxygen concentration cells, and may generate high stresses by the oxide growth mechanism. The worst crevices are those with corrosive impurities and metal temperature within the "salt zone." Some disc bore and keyway and blade tenon-shroud crevices fall into this category.

- *Galvanic effects*—When dissimilar materials are coupled together, corrosion of both materials can be affected by the associated shift in corrosion potentials into the stress corrosion cracking (SCC) or pitting regions. The more active of the two materials may suffer galvanic corrosion. In addition, in some environments, the potential shift could be into the region where one of the coupled materials is susceptible to stress corrosion cracking or pitting.

- *Inspectability*—In designing turbine components, the question of inspectability should be addressed. In particular, crevice and high stress regions should be reachable using available inspection techniques.

- *Chemical compounds used during machining, cleaning, nondestructive testing (NDT), and other activities*—Many different chemical compounds are used during manufacture, storage, erection, and inspection of turbine components. Some of them contain chlorine and sulfur as impurities or as a part of the organic matrix. During thermal decomposition of the residues of these compounds, hydrochloric, sulfuric, carbonic, and organic acids can form (Jonas, 1982). It is recommended that their composition and use be carefully controlled to minimize the risk of residual contamination and subsequent corrosion. For the compounds that can remain on turbine surfaces during operation, chlorine and sulfur levels should be restricted to low ppm levels in that compound. Of specific concern are: MoS_2 (Molylube™) (Turner, 1974; Newman, 1974), Loctite™, thread compounds (Cu, Ni, graphite), and chlorinated solvents.

Materials and Corrosion Data

There is little variation in the materials used for blades, discs, rotors, and turbine cylinders, and only a few major changes have been introduced in the last decade. Titanium alloy blades are being slowly introduced for the last LP stages, and better melting practices to provide control of inclusions and trace elements are being evaluated for discs and rotors. Table 2 (Jonas, 1985a) lists common materials and the typical corrosion mechanisms for the various turbine components.

Table 2. LP Turbine Components, Materials, and Related Corrosion Mechanisms.

Component	**Material**	**Corrosion Mechanisms***
Rotor	CrMoV, NiCrMoV low alloy steel forging	P, SCC, CF
Discs	NiCrMoV, CrMoV, NiCrMo low alloy steel forging, 12Cr weld repair	P, SCC, CF, FAC
Blades and shrouds	12Cr stainless steels, 15-5PH, 17-4 PH, Ti6-4, PH13-8Mo, Fe-26Cr-2Mo	P, SCC, CF
Tie wires	12Cr stainless steels (ferritic and martensitic)	SCC, P, CF
Dovetail pins	CrMo low alloy steels, 5CrMoV, similar to ASTM A681 Grade H-11	SCC
Erosion shields	Stellite Type 6B – weld deposited or soldered, same as blade	SCC, E
Stationary blades	304 SS, other stainless steels	SCC, LCCF
Shell and piping	Carbon steel	FAC, SCC
Expansion bellows	AISI Types 321 or 304 stainless steels, Inconel 600	SCC, LCCF
* P – pitting, SCC – stress corrosion cracking, CF – corrosion fatigue, FAC – flow-accelerated corrosion, LCCF – low cycle corrosion fatigue, E – erosion		

LP rotors are typically constructed of forgings conforming to ASTM A293 (Class 2 to 5) or ASTM A470 (Class 2 to 7), particularly 3.5NiCrMoV. Shrunk-on discs, when used, are made from forgings of similar NiCrMoV materials conforming to ASTM A294 (Grade B or C), or ASTM 471 (Classes 1 to 3). The strength and hardness of turbine components must be limited because the stronger and harder materials become very susceptible to SCC and CF (EPRI, 1998a); particularly turbine rotors, discs, and blades cannot be made from high strength materials.

The crack propagation rate increases exponentially with yield strength at high yield strength values and SCC starts being influenced by hydrogen embrittlement. Because of this sensitivity to high yield strength, practically all turbine discs, fossil and nuclear, with yield strength higher than ~140 ksi (965 MPa) have been replaced with lower strength materials. Figure 6 is a correlation of crack propagation rates versus yield strength for several operating temperatures (Clark, et al., 1981). This type of data has been used to predict the remaining life and safe inspection interval. There is also an upper temperature limit for LP rotor and disc steels, ~650°F (345°C) aimed at avoiding temper embrittlement (EPRI, 1998a).

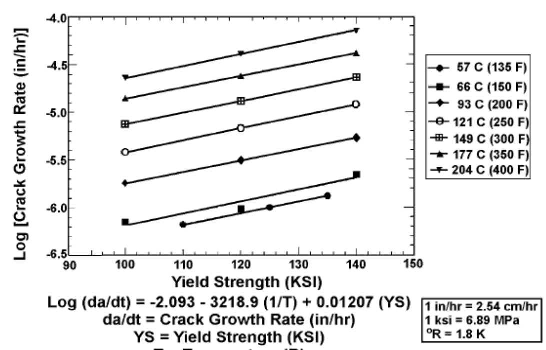

Figure 6. Average Crack Growth Rates Versus Yield Strength for Several Operating Temperatures for NiCrMoV Disc Steel. (Courtesy of Clark, et al., 1981)

Since the 1930s, most LP turbine blades have been manufactured from a 12%Cr stainless steel—typically types AISI 403, 403-Cb, 410, 410-Cb, and 422, depending on the strength required. Types 403 and 410 have better SCC and CF resistance than Type 422, an important characteristic for use in the wet stages of the LP turbine. There are numerous specifically customized versions of these generic materials (Carpenter H-46, Jethete M152 (modified 403), etc.).

The precipitation hardened stainless steels designated 17-4 PH, 15-5PH, and PH13-8Mo have been used for some fossil and nuclear LP turbine blades. The composition of 17-4PH is 17 percent Cr, 4 percent Ni, and 4 percent Cu. These steels may be difficult to weld and require post-weld heat treatment. The copper rich zones in the copper bearing stainless steels are often subject to selective dissolution, forming pits filled with corrosion products. These pits can be crack initiation sites.

Titanium alloys, primarily Ti-6Al-4V, have been used for turbine blades since the early 1960s (EPRI, 1984d, 1984e, 1985c). There are numerous benefits to using titanium alloy blades, including the ability to use longer lasting stage blades, favorable mechanical properties in applications involving high stresses at low temperatures, excellent corrosion resistance, and resistance to impact and water droplet erosion damage. Drawbacks to titanium include higher cost, difficult machining, and low material damping.

LP turbine casings are typically constructed of welded and cast components. Materials acceptable for lower temperatures, such as carbon steel plate, are used.

Considering the typical steam turbine design life of 25 to 40 years and the relatively high stresses, these materials have been performing remarkably well. Turbine steels are susceptible to SCC and CF in environments such as caustic, chlorides, acids, hydrogen, carbonate-bicarbonate, carbonate-CO_2, and, at higher stresses and strength levels, in pure water and steam.

Corrosion Data

Corrosion data should provide allowable steady and vibratory stresses and stress intensities for defined design life or inspection intervals. It is suggested that SCC data include threshold stress (σ_{SCC}), threshold stress intensity (K_{ISCC}), crack growth rate (da/dt), and crack incubation and initiation times. Corrosion fatigue data should include fatigue limits for smooth and notched surfaces and proper stress ratios, crack growth data, and corrosion fatigue threshold stress intensities.

Examples of the type of data needed are shown in Figures 7 to 9 for the NiCrMoV disc material and in Figure 10 for 12%Cr blade steel. Properly heat treated 12%Cr blade steel (yield strength ≤ 85 ksi, 600 MPa) is not susceptible to stress corrosion cracking and stress corrosion data are not needed. The data shown in Figures 7 to 10 can be used in turbine disc and blade design in which the allowable stresses and stress intensities should be below the threshold values for SCC and CF. The use of these data is outlined in (Jonas, 1985c).

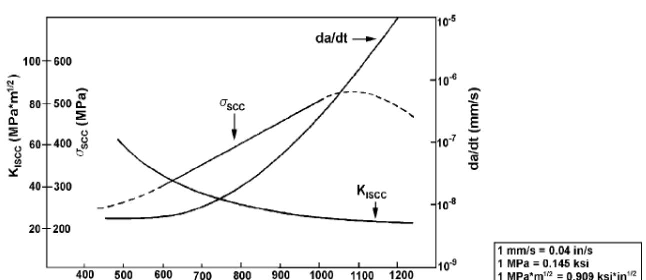

Figure 7. Stress Corrosion Behavior of NiCrMoV Disc Steel Versus Yield Strength for "Good" Water and Steam (Compiled from Published Data); K_{ISCC}—Threshold Stress Intensity, σ_{SCC}—Threshold Stress, and da/dtq—Stage 2 Crack Growth Rate. (Courtesy of Jonas, 1985a)

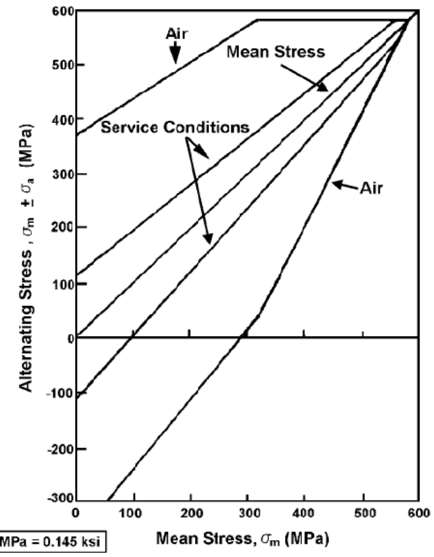

Figure 8. Corrosion Fatigue (Goodman) Diagram for NiCrMoV Disc Steel; Tested to 10^8 Cycles. (Courtesy of Haas, 1977)

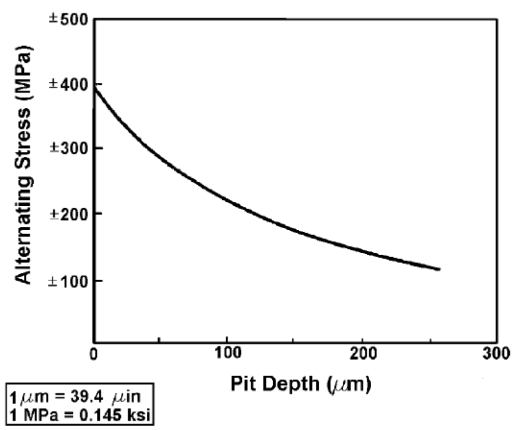

Figure 9. Air Fatigue Strength Reduction of NiCrMoV Disc Steel Caused by Pitting (Courtesy of McIntyre, 1979)—Effects of Pit Density Were Not Investigated.

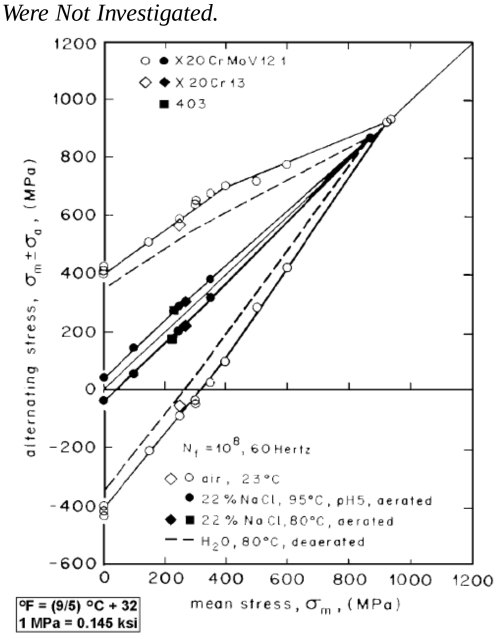

Figure 10. Corrosion Fatigue (Goodman) Diagram for Three Stainless Steel Blading Alloys. (Courtesy of Atrens, et al., 1984)

The needed data are difficult to obtain because of the long time needed for testing and because of the great range of possible service environments and temperatures. There does not seem to be any universally accepted accelerated test or environment. The K_{ISCC} test in hydrogen sulfide gives a reasonable approximation of K_{ISCC} for low alloy steels, and ultrasonic fatigue tests give usable data to a high number of cycles that may be usable for turbine design.

As a rule of thumb, the elasticity limit at temperature (usually between 0.4 and 0.6 of the 0.2 percent yield strength) can be used as a good estimate of the SCC threshold stress for low and medium strength materials in mildly corrosive environments. This is consistent with the oxide film rupture or strain induced cracking theory of stress corrosion cracking.

Shot peening (EPRI, 2001b)—has been used as a means of reducing high surface tensile stresses. At a sufficiently high shot peening intensity, a surface layer of residual compressive stresses is produced. One turbine vendor uses shot peening and other surface treatments extensively and they have almost no SCC of discs and corrosion fatigue (CF) of turbine blades. There is a concern that in corrosive environments, pits can grow through the compressive stress layer into the subsurface region with much higher tensile stresses.

Other surface treatments for protection against corrosion, such as coatings and electroplating, have been evaluated (EPRI, 1987a, 1993a, 2001b; Jonas, 1989) and sometimes used. There are now several suppliers of steam turbine coatings (EPRI, 1987a, 1993a; Jonas, 1989).

Environment—Stress—Material

Turbine stress corrosion cracking and high- and low-cycle corrosion fatigue mechanisms are typically governed by a combination of environmental effects (steam chemistry, temperature, etc.), steady and vibratory stresses, and material strength, composition, and defects (Figure 11). It should be noted that even pure water and wet steam can cause cracking of turbine materials, particularly in the low alloy rotor and disc steels, and that medium and high strength materials are very susceptible to environmentally induced cracking in any environment, including pure water and steam.

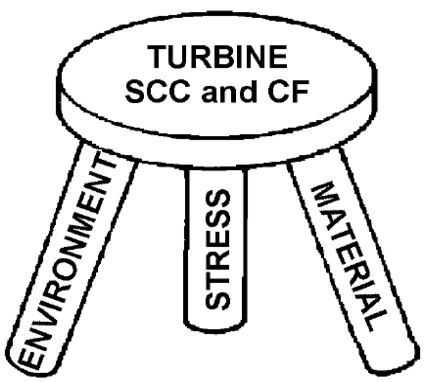

Figure 11. Three Components of Turbine Stress Corrosion and Corrosion Fatigue Cracking in Turbines.

Turbine environment plays a major role in corrosion during operation and layup. The uniqueness of this environment is caused by the phase changes of the working fluid and the impurities carried by the steam (steam, moisture, liquid films, and deposits). Within the steam flow path and on the turbine component surfaces, the parameters controlling corrosion, such as pH, concentration of salts and hydroxides, and temperature, can change within a broad range. Even though steam impurity concentrations are controlled in the low parts per billion (ppb) range, these impurities can concentrate by precipitation, deposition, and by evaporation of moisture to percent concentrations, becoming very corrosive (Figures 12 and 13) (EPRI, 1994a, 1997b, 1997c, 1999; Jonas, et al., 1993).

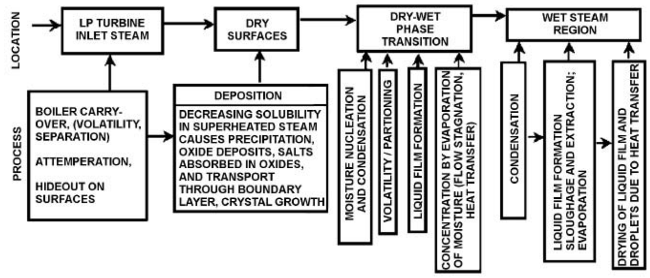

Figure 12. Physical-Chemical Processes in LP Turbines.

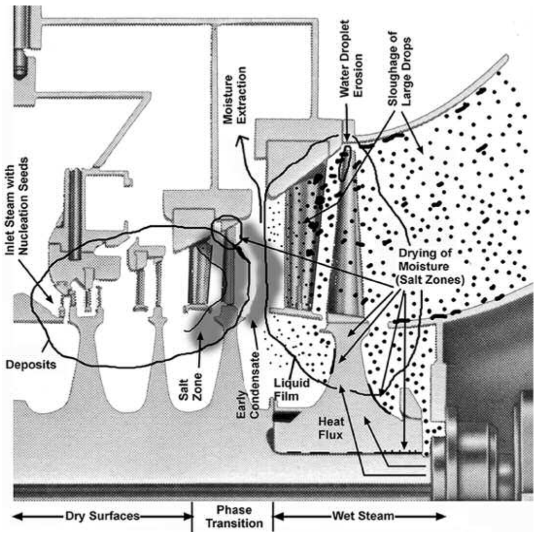

Figure 13. Cross Section of an LP Turbine with the Locations of the Processes Listed in Figure 15-11.

Steam Chemistry

Steam chemistry or purity, together with the thermodynamics and flow design, determines corrosiveness of the deposits and liquid films on turbine component surfaces (Jonas, 1982, 1985a, 1985d; Jonas and Dooley, 1996, 1997; EPRI, 1984b, 1994a, 1997b, 1997c, 1999; Jonas, et al., 1993; Jonas and Syrett, 1987; Schleithoff, 1984). In fossil units, the LP turbine requires the lowest concentration of impurities in the cycle, that is, low parts per billion concentrations (1 ppb is 1 µg/liter). Steam purity is controlled by the purity of makeup, condensate, and feedwater and in drum boilers by boiler water chemistry, boiler pressure, and carryover. As a minimum, steam purity should be monitored by isokinetic sampling and by analysis of sodium and cation conductivity (EPRI, 1986, 1994c, 1998b, 1998c, 2002a; Jonas, 2000).

The corrosiveness of the steam turbine environment is caused by one or more of the following:

- Concentration of impurities from low ppb levels in steam to percent levels in steam condensates (and other deposits) resulting in the formation of concentrated aqueous solutions
- Insufficient pH control and buffering of impurities by water treatment additives such as ammonia
- High velocity and high turbulence flow of low-pH moisture droplets (FAC)

The situation is generalized in Figure 14, which is a Mollier diagram showing the LP turbine steam expansion line and thermodynamic regions of impurity concentrations (NaOH, salts, etc.) and resulting corrosion. Low volatility impurities in the "salt zone" are present as concentrated aqueous solutions. The NaCl concentration can be as high as 28 percent. Note that the conditions at the hot turbine surfaces (in relation to the steam saturation temperature) can shift from the wet steam region into the salt zone and above. This can be the reason why disc stress corrosion cracking often occurs in the wet steam regions. The surfaces may be hot because of heat transfer through the metal or because of the stagnation temperature effect (zero flow velocity at the surface and change of kinetic energy of steam into heat).

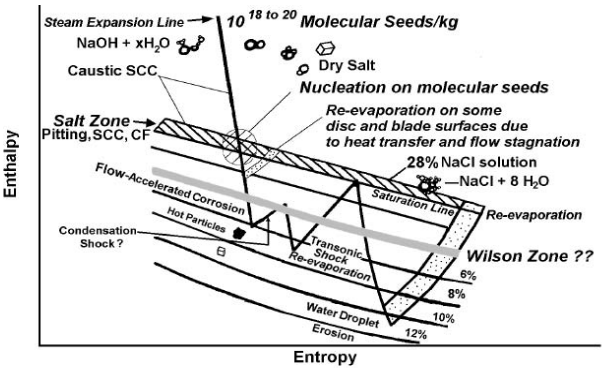

Figure 14. Mollier Diagram with LP Steam Expansion Line and Thermodynamic Regions for Impurity Concentration and Corrosion Mechanisms.

The impurity concentration mechanisms include:

- Precipitation from superheated steam and deposition.
- Evaporation and drying of moisture on hot surfaces.
- Concentration on oxides by sorption.
- Nonhomogeneous nucleation of concentrated droplets and crystals on surfaces.

Dissolved impurities deposit from superheated steam when their concentration exceeds their solubilities, which sharply decreases as the steam expands. Depending on their vapor pressure, they can be present as a dry salt or an aqueous solution. In the wet steam region, they are either diluted by moisture or could concentrate by evaporation on hot surfaces.

The region of passivity for iron and low alloy and carbon steels is narrow, falling within the pH range of 6 to 10. Since pH control in a power plant is mostly for the protection of the preboiler cycle and the boiler, it often does not match the needs of the turbine surfaces. The pH in the turbine depends on temperature, mechanical and vaporous carryover of impurities, and water treatment chemicals from the boiler and their volatility (distribution between the vapor and the surface film).

When hydrochloric acid forms in cycles with ammonia all-volatile treatment (by decomposition of chlorinated organics, Cl^- leakage from polishers, or seawater or other cooling water leakage in the condenser), ammonium chloride forms in the water, and the acid may be neutralized. However, because of its volatility, ammonium chloride is transported with steam into the turbine where it hydrolyzes, forming NH_3 gas and HCl.

Deposits on turbine surfaces in units with sodium phosphate boiler water treatment (most drum boilers) are less corrosive (Jonas and Syrett, 1987; EPRI, 1984b; Jonas, 1985d). Sodium phosphate is a better neutralizing agent through the cycle; fewer acids are transported into the turbine and phosphate frequently codeposits with harmful impurities, providing in-situ neutralization and passivation. This is most likely the reason for lower frequency of turbine corrosion in systems with phosphate water treatments. Measurements of pitting potential of disc and blading alloys confirm the beneficial effects of sodium phosphate in the presence of NaCl.

Besides the corrosion during operation, turbines can corrode during manufacture (corrosive products from machining fluids, exposure to tool tip temperatures), storage (airborne corrosive impurities, preservatives containing Cl and S), erection (airborne impurities, preservatives, cleaning fluids), chemical cleaning (storage of acid in hotwells), nondestructive testing (chlorinated cleaning and NDT fluids), and layup (deposits plus humid air). Many of these corrosive substances may contain high concentrations of sulfur and chloride that could form acids upon decomposition. Decomposition of typical organics, such as carbon tetrachloride occurs at about 300°F (150°C). The composition of all of the above compounds should be controlled (maximum of 50 to 100 ppm S and Cl each has been recommended), and most of them should be removed before operation.

Molybdenum disulfide, MoS_2, has been implicated as a corrodent in power system applications (Turner, 1974; Newman, 1974). It can cause stress corrosion cracking of superalloys and steels by producing an acidic environment. Its oxidation products form low pH solutions of molybdic acid and even ammonium molybdate, which can form during operation, causing rapid attack of turbine steels. MoS_2 has been used as a thread lubricant and in the process of disc-rotor assembling when the discs are preheated and shrunk on the rotors. Analysis of disc bore and keyway surfaces often reveals the presence of molybdenum and sulfur. In steam, MoS_2 reduces the notch strength of disc steel, to about 30 percent of its strength in air. It has also been implicated in bolt and rotor shaft failures.

Layup corrosion of unprotected turbines increases rapidly when the relative humidity of air reaches about 60 percent. When salt deposits are present, pitting during unprotected layup is rapid. Pit growth in turbine blade and rotor alloys in chloride-metal oxide mixtures in wet air is about as fast as in a boiling deaerated 28 percent NaCl solution. Turbine layup protection by clean dry air is recommended.

Progress in controlling turbine corrosion through better control of the steam chemistry includes (Jonas, 1982, 1985d, 1994; EPRI, 1984b, 1986, 1994a, 1994c, 1997b, 1997c, 1998b, 1998c, 1999, 2002a; Jonas, et al., 1993, 2000; Jonas and Syrett, 1987; Schleithoff, 1984, "Progress in...," 1981):

- Decreasing concentration of corrosive impurities in makeup and feedwater, lower air inleakage and condenser leakage, etc.
- Oxygenated water treatment for once-through fossil units for excellent feedwater chemistry and clean boilers.
- Layup protection.
- Turbine washing after chemical upsets to remove deposited impurities.
- Reduction or elimination of copper and its oxides and their synergistic corrosion effects by reducing oxygen concentration, operating with a reducing (negative oxidation-reduction potential [ORP]) environment and a low ammonia concentration, or by replacing copper alloys with steel or titanium.

PROBLEMS, THEIR ROOT CAUSES, AND SOLUTIONS

Steam turbine corrosion damage, particularly of blades and discs, has long been recognized as a leading cause of reduced availability (Scegljajev, 1983; McCloskey, 2002; Sanders, 2001; Cotton, 1993; Jonas, 1985a, 1987; EPRI, 1981, 1998a, 2001b; Jonas and Dooley, 1996, 1997; NERC, 2002). It has been estimated that turbine corrosion problems cost the U.S. utility industry as much as one billion dollars per year (EPRI, 1985b, 2001a; Syrett, et al., 2002; Syrett and Gorman, 2003; Jonas, 1986) and that the cost for industrial turbines, which suffer similar problems, is even higher.

In this section, the main corrosion problems found in LP turbines and their root causes are summarized, and solutions to reduce or eliminate each problem are discussed. The field monitoring equipment shown in Figure 15 can be used to diagnose and prevent many common LP turbine corrosion and deposition problems (EPRI, 1997c, 2001b; Jonas, 1994; Jonas, et al., 2007). In addition, there are also monitors available to detect vibration, blade and rotor cracking, steam leaks, air inleakage, rotor position, and wear of bearings (Jonas, et al., 2007).

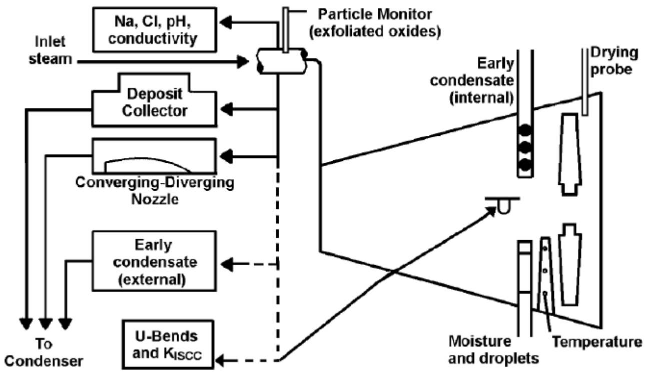

Figure 15. LP Turbine Troubleshooting Instrumentation Can Identify Specific Corrosive Conditions. (Courtesy of EPRI, 1997c)

An overview of the low-pressure turbine corrosion problems together with erosion and other problems is given in Table 3. The problems are listed according to their priority and impact with disc rim blade attachment stress corrosion cracking being the highest impact problem today because of the long time required for weld repair or procurement of a new disc or new rotor (up to six months). Cracking of discs, corrosion fatigue of the rotor shaft, and fatigue or corrosion fatigue of long blades can become a safety issue because they can lead to perforation of the casing and other destructive events (EPRI, 1981, 1982a, 1998a; Jonas, 1977; Turner, 1974). It is estimated that inadequate mechanical design (high steady and vibratory stresses, stress concentration, and vibration) is responsible for about 50 percent of the problems, inadequate steam chemistry for about 20 percent, and nonoptimum flow and thermodynamic design for about 20 percent. Poor manufacturing and maintenance practices account for the remaining 10 percent of the problems.

Table 3. LP Turbine Corrosion, Erosion, and Deposition Problems.

	Problem	Damage[1] Mechanisms	Root[2] Causes	Inspection[3] and Detection	Possible Safety Issues	Cost[4] per Event ($ millions)
1	Disc/blade attachment cracking	SCC, CF, P	D, CH	UI, V, MP	Turbine wreck	1 – 20
2	Disc bore cracking	SCC, P	D, M	UI	Turbine wreck	2 – 20
3	Blade airfoil cracking	CF, P, WE	D, CH	V, VSA	Penetration of casing	0.1 – 2
4	Blade root cracking	CF, SCC, P	D, CH	V, UI	Penetration of casing	0.2 – 2
5	Dovetail pin cracks	SCC	D	V, UI	None	0.1 – 0.5
6	Blade tenon, shroud, and snubbers	CF, SCC, P	D, CH, M	V, UI	None	0.1 – 1
7	Blade pitting during erection and layup	P	CH - deposition	V	None	0.1 - 10
8	Blade airfoil damage	FOD	Cleanliness, M	V, particle monitoring	None	0.1
9	Stationary blade cracking	CF, P	D, O	V, DP	None	Low
10	Rotor cracking	CF, F, P	D	MP, VSA	Turbine wreck	2 – 10
11	Casing bolt, casting, and weld cracking	SCC	D, M, CH	V, DP, UI, MP	Steam leak	0.1 - 1
12	Casing and extraction piping	FAC	D, CH	V, UI	Steam leak	0.1 – 1
13	Cross-over pipe, expansion bellows	SCC	D, CH	V, UI, leak	Steam leak	0.1 - 2
14	Thrust bearing wear	Wear	CH – deposits	V, rotor position	Turbine wreck	0.1 - 5
15	Loss of MW and efficiency	Deposits, P, FOD, WE	CH, D, O, A	V, performance monitoring	None	Up to 2/year

CF – corrosion fatigue, SCC – stress corrosion cracking, P – pitting, FAC – flow-accelerated corrosion, LCCF – low cycle corrosion fatigue, WE – water droplet erosion, FOD – foreign object damage
D – design and material selection, CH – chemistry, O – operation, A – age, M – manufacturing and maintenance
V – visual, UI – ultrasonic inspection, MP – magnetic particle, EC – eddy current, DP – dye penetrant, VSA – vibration signature analysis
Lost production and repairs per one event. The cost of lost production is typically much higher than the loss from repairs with a ratio up to 10:1

When a corrosion problem is discovered during inspection or by equipment malfunction, the failure mechanism and the root causes are not always known. Even when the damage fits a description of a well-known problem (disc or blade cracking), replacement parts may not be readily available and the decision for what to do has to be made quickly. The main objectives in handling identified and potential problems are maintaining safety and avoiding forced outages. The questions should be asked: can we operate safely until the next planned inspection or overhaul? If not, what is the safe inspection interval? If repeated failures are likely and repair would take a long time and lead to a large loss of production, spare rotors may be a good economical solution.

Data collected by the North American Electric Reliability Council (NERC) for 1476 fossil units between 1996 and 2000 shows that LP turbines were responsible for 818 forced and scheduled outages and deratings, causing the utilities a 39,574 GWh production loss. The outages are often characterized as "low frequency high impact events." (NERC, 2002) shows the components that were responsible for the failures as well as the MWh losses associated with the failures. Many of these outages are caused by corrosion (except for bearings).

Table 4. Forced and Schedule Outages and Deratings Caused by LP Turbine Components for the Years 1996 to 2000 (1476 Units, 168 Utilities).

Component	Total Occurrences	Outages/ Unit-Year*	Total MWh Losses for All Units	MWh/ Unit-Year*	MWh/ Outage
Outer Casing	11	0.002	$5.1x10^4$	7.6	4,698
Inner Casing	24	0.004	$9.4x10^5$	139.0	39,210
Diaphragms	37	0.005	$1.3x10^6$	185.9	34,014
Buckets or Blades	194	0.029	$1.5x10^7$	2,241.3	78,222
Bucket or Blade Fouling	10	0.001	$9.5x10^5$	140.6	95,209
Wheels or Spindles	2	0.000	$6.1x10^4$	9.0	30,533
Shaft Seals	37	0.005	$3.4x10^5$	50.7	9,283
Gland Rings	3	0.000	$1.0x10^4$	1.5	3,422
Rotor Shaft	43	0.006	$6.1x10^6$	905.2	142,529
Bearings	265	0.039	$9.0x10^7$	1,329.7	33,973
Other Problems	192	0.028	$5.7x10^6$	834.5	39,428

* - Total Number of Unit-Years = 6771

Life Prediction and Inspection Interval

Experience shows that pits and ground-out stress corrosion cracks can remain in-service for several years, depending on stress and environment. However, components containing high-cycle corrosion fatigue cracks should not be left in-service. Procedures for prediction of residual life and determination of a safe inspection interval have been developed for all major failure mechanisms including SCC, CF, fatigue, FAC, and creep. The procedures for SCC of turbine discs (Clark, et al., 1981; EPRI, 1989; Rosario, et al., 2002), low cycle corrosion fatigue, and FAC (EPRI, 1996) have been successfully applied because all variables influencing these mechanisms can be reasonably predicted or measured. However, life prediction for high cycle corrosion fatigue and fatigue has not been so successful because the vibratory stresses and the corrosiveness of the environment are usually not accurately known.

Life prediction is based on results of inspection, fracture mechanics analysis of components with defects, and application of SCC and CF crack growth data. Time or number of load cycles to reach ductile or brittle fracture is predicted and a safety factor is applied to determine the time for the next inspection. In the procedure used by OEMs and Nuclear Regulatory Commission (NRC) for nuclear turbines for determining the inspection interval for turbine discs under SCC conditions, the safety factor of two was applied to the predicted time-to-failure.

Stress Corrosion Cracking of Discs

Stress corrosion cracking of LP turbine disc keyways and blade attachments have been the two most expensive generic problems in large steam turbines (Cheruvu and Seth, 1993; EPRI, 1982a, 1982b, 1984a, 1984c, 1985a, 1985d, 1987b, 1989, 1991a, 1997a, 1998d; Jonas, 1978; Speidel and Bertilsson, 1984; Clark, et al., 1981; Rosario, et al., 2002; Nowak, 1997; Kilroy, et al., 1997; Amos, et al., 1997; Turner, 1974; Newman, 1974; Parkins, 1972; Holdsworth, 2002). The keyway cracking problem has been resolved by redesigns of the shrunk-on or bolted-on discs, material replacement with lower strength material, and by elimination of the corrosive disc bore lubricants, based on molybdenum disulfide (MoS_2), used in assembling the rotor. SCC of blade attachments of various designs is still a problem (EPRI, 1997d, 1998a, 2002c; Nowak, 1997).

There are several corrosion damage mechanisms and many factors affecting discs (Figure 16). Typical locations and orientations of SCC cracks in LP discs are shown in Figures 17 and 18. There has also been SCC in pressure balance holes. Most incidents of disc rim attachment cracking have been found in nuclear units, however, there have also been problems in fossil units. In an independent survey, 13 of 38 (35 percent) boiling water reactors (BWRs) and 28 of 72 (39 percent) pressurized water reactors (PWRs) reported disc rim attachment cracking while 29 of 110 (26 percent) supercritical fossil units and only 20 of 647 (3 percent) subcritical units reported cracking (EPRI, 1997d). Disc rim blade attachment cracking occurred in multiple-hook (steeple), fir tree attachment designs (typically occurs in the corners of the hooks), in straddle mount dovetail and pinned-finger attachments, and in T-roots. It is always associated with stress concentrations.

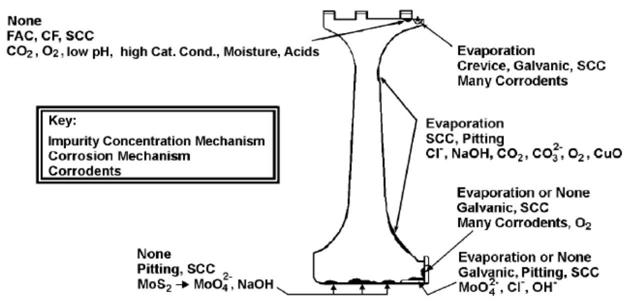

Figure 16. Crack Locations in Turbine Discs with Probable Impurity Concentration and Corrosion Mechanisms and Corrodents. (Courtesy of Jonas, 1985a)

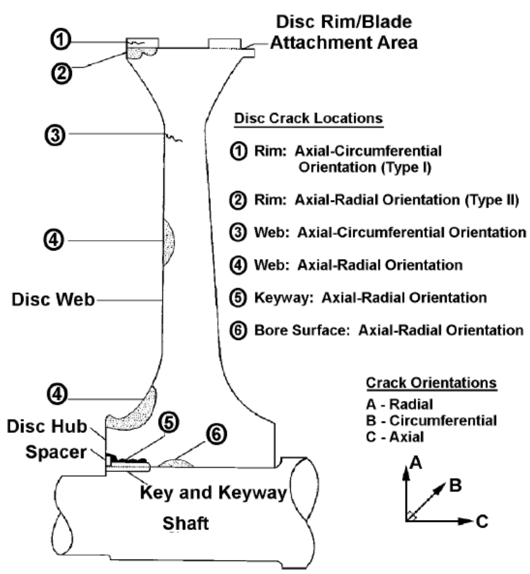

Figure 17. Typical Locations and Orientations of SCC Found in LP Turbine Discs. (Courtesy of EPRI, 1982a)

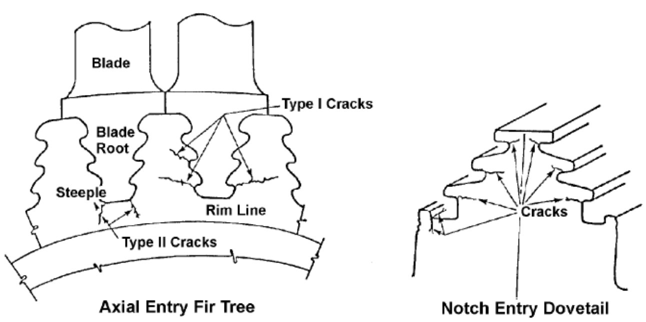

Figure 18. Typical Locations of Disc Rim Cracking. (Courtesy of EPRI, 1982a)

Materials—All low alloy steels used for LP turbine rotors and discs are susceptible to SCC and CF in numerous turbine environments including pure water and wet steam. The strongest material factor influencing SCC is yield strength. At higher yield strength, SCC crack growth rate can be several orders of magnitude higher than for lower yield strength materials. The purity of the material and the steel melting practices mostly influence the fracture toughness, which determines the maximum tolerable crack size before a disc brittle fracture and burst.

Fractography—SCC cracks of low alloy steels often initiate from pits and propagate intergranularly with branching. The initial part of the crack can be corroded and filled with magnetite. There could be beach marks or stretch marks, caused by overloading the crack during overspeed testing. Another type of beach mark can be caused by changes of the environment or by fatigue. Depending on the ratio of the steady and cyclic stresses, the disc cracks can be a mixture of intergranular and transgranular cracking. Figure 19 shows an SCC crack initiating at the radius of the upper serration of L-1 blade steeple. The intergranular crack initiated from a pit.

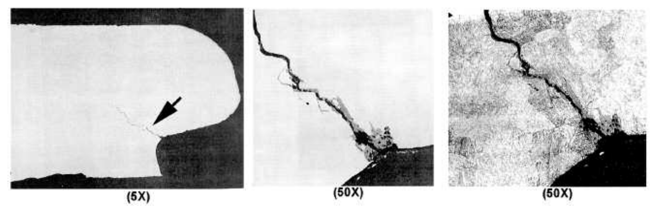

Figure 19. SCC Crack in the Upper Steeple Serration-L-1 Blade Attachment.

The factors that determine the SCC crack initiation time and propagation rate include material yield strength, surface stress, temperature, and the local chemical environment. Some of these relationships are shown in Figures 6 and 7. At yield strengths above ~135 ksi (930 MPa), these low-alloy steels show high SCC growth rates.

Pitting often initiates SCC. When corrosive deposits are present, pitting during unprotected layup can be faster than pitting during operation. This is because during the layup, there can be 100 percent relative humidity and there is oxygen present. At high stresses, above the elasticity limit of the material, pitting is enhanced through the mechanism identified as stress induced pitting (Parkins, 1972). In some cases, blade attachment cracking is a combination of stress corrosion cracking and corrosion fatigue because of the effects of blade vibration.

Root Causes

SCC of discs (at keyways, bores, and blade attachments) is caused by a combination of high surface stresses, a susceptible material, and operational and shutdown environments. Design-related root causes are the most important and prevalent. They include high surface tensile stresses and stress concentrations, and use of high strength materials.

Sources of stresses that contribute to SCC of discs include:

- Basic centrifugal load caused by rotor rotation. Locally high concentration of centrifugal loads caused by variation in the gaps (gauging) between blade and disc rim attachment.
- Residual machining stresses.
- Vibratory stresses—interaction of SCC and corrosion fatigue. Also, vibratory stresses reduce the life of the cracked disc when the flaws reach a sufficient size that fatigue becomes a dominant mechanism.

Steam chemistry root causes of SCC and CF cracking include:

- Operating outside of recommended steam purity limits for long periods of time; sometimes caused by organic acids from decomposition of organic water treatment chemicals.

- Condenser leaks—minor but occurring over a long period of time.
- Condenser leaks—major ingress, generally one serious event, and the system and turbine not subsequently cleaned.
- Water treatment plant or condensate polisher regeneration chemicals (NaOH or H_2SO_4) leak downstream.
- Improperly operated condensate polisher (operating beyond ammonia breakthrough, poor rinse, etc.).
- Shutdown environment: poor layup practices plus corrosive deposits.

Sodium hydroxide is the most severe SCC environment encountered in steam turbines. The sources of NaOH include malfunctioning condensate polishers and makeup systems and improper control of phosphate boiler water chemistry combined with high carryover. Many other chemicals can also cause SCC of low alloy steels. The chemicals used in turbine assembly and testing, such as molybdenum disulfide (lubricant) and Loctite™ (sealant containing high sulfur), can accelerate SCC initiation (Turner, 1974; Newman, 1974).

Solutions

In most cases where material yield strength is <130 ksi (895 MPa), the solution to disc SCC is a design change to reduce stresses at critical locations. This has been achieved by eliminating keyways or even disc bores (welded rotors) and by larger radii in the blade attachments. Higher yield strength (>130 ksi, 895 MPa) low alloy steel discs should be replaced with lower strength materials. The goal is to keep the ratio of the local operating stress to yield stress as low as possible, ideally aiming for the ratios to be less than 0.6. Minimizing applied stresses in this manner is most beneficial in preventing initiation of stress corrosion cracks. Once cracks begin to propagate, a reduction in stress may be only marginally effective unless the stress intensity can be kept below ~10 to 20 ksi-in$^{1/2}$ (11 to 22 MPa-m$^{1/2}$). This is because of the relative independence of the crack growth rate over a broad range of stress intensities. For many rim attachment designs, such levels of applied stress intensity are impossible to achieve once an initial pit or stress concentration has formed. An emerging solution to disc rim stress corrosion cracking is a weld repair with 12%Cr stainless steel. Another solution has been to shot peen the blade attachments to place the hook fit region into compression.

Good control of the steam purity of the environment can help to prevent or delay the SCC. Maintaining the recommended levels of impurities during operation and providing adequate protection during shutdown can help minimize the formation of deposits and corrosive liquid films, and lengthen the period before stress corrosion cracks initiate. The operating period(s), events, or transients that are causing excursions in water and steam chemistry should be identified using the monitoring locations and instrumentation recommended in the independent water chemistry guidelines (EPRI, 1986, 1994c, 1998b, 1998c, 2002a; Jonas, et al., 2000) and special monitoring as shown in Figure 15 and elsewhere (EPRI, 1997c, 2001b; Jonas, et al., 2007).

Corrosion Fatigue and
Stress Corrosion Cracking of Blades

LP turbine blades are subject to CF, SCC, and pitting of the airfoils, roots, tenons and shrouds, and tie wires (Holdsworth, 2002; EPRI, 1984c, 1984d, 1985c, 1985d, 1987c, 1991b, 1993b, 1994b, 1998d; Jaffe, 1983; Evans, 1993; Singh, et al.; *BLADE-ST*™, 2000). Figure 20 depicts the typical locations on an LP turbine rotating blade that are affected by localized corrosion and cracking. In addition, the blade surfaces are also subject to fatigue, deposition, water droplet erosion, and foreign object damage. CF is the leading mechanism of damage. It is a result of the combination of cyclic stresses and environmental effects. There are always environmental effects in fatigue cracking in LP turbines (EPRI, 1984d, 1984e) and all fatigue cracking should be considered corrosion fatigue. The fatigue limit of all turbine materials in turbine environments including pure steam is lower than the air fatigue limit. Corrosion fatigue cracks often originate from pits.

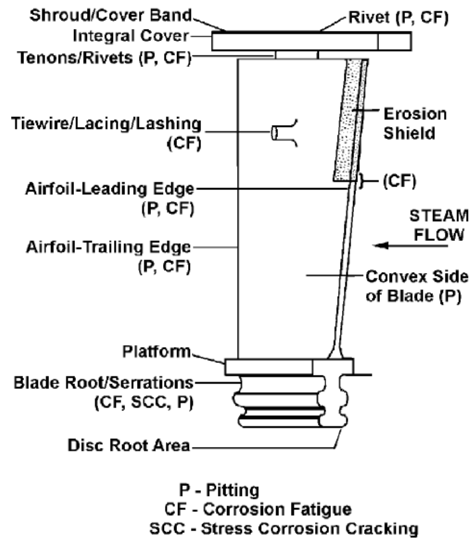

Figure 20. Typical Locations of Cracking and Localized Corrosion on LP Turbine Rotating Blades. There Has Also Been SCC and CF Cracking in the Tiewire Holes. (Courtesy of EPRI, 1998a)

Figures 21 and 22 show corrosion fatigue cracks of L-1 blade root and airfoil, respectively. Figure 23 illustrates pitting in the blade tenon-shroud area, which sometimes initiates corrosion fatigue cracking. Fractography shows that CF blade cracking often initiates from a pit, continuing for 50 to 150 mils (1.3 to 3.8 mm) by intergranular cracking and then proceeding as a flat fatigue fracture with beach marks and striations.

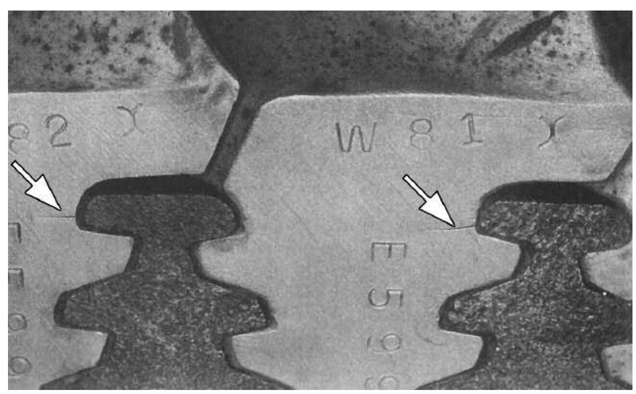

Figure 21. Corrosion Fatigue of L-1 Blade Attachment. (Courtesy of EPRI, 1998a)

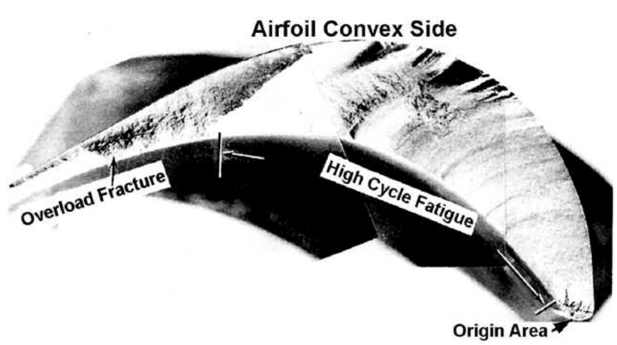

Figure 22. Corrosion Fatigue of L-1 Blade Airfoil. (Courtesy of EPRI, 1981)

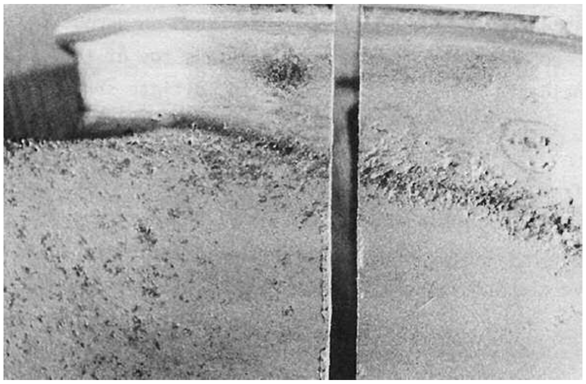

Figure 23. Pitting in the L-1 Blade Tenon-Shroud Area. (Courtesy of EPRI, 1981)

Damage by corrosion fatigue occurs in the last few rows of LP turbines, mostly in the phase transition zone (PTZ) (salt zone shown in Figure 14). The PTZ moves according to load changes, but is typically near the L-1 row in most LP fossil turbines (Figure 24). Units that increase cycling duty may be subject to worsened corrosion fatigue problems. As the unit is ramped up and shut down, the blades pass through resonance more frequently and the phase transition zone shifts, potentially affecting more stages during the transients. In addition, the steam purity can be significantly worse during transients than during steady-state operation, and if the unit is shut down as part of the cycling operation, significant degradation of the local environment can occur (deposits and humid air).

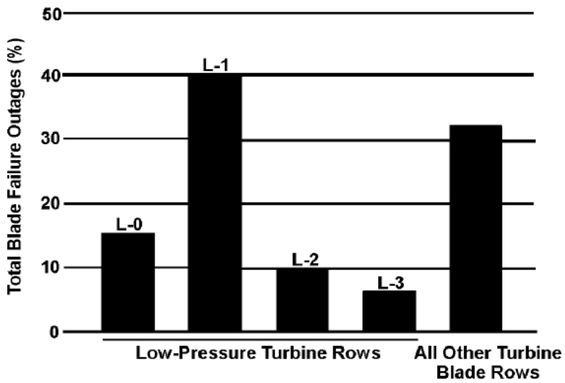

Figure 24. Distribution of Blade Failures in U.S. Fossil Turbines by Row. (Courtesy of Power, 1981)

Causes of blade and blade attachment failures are listed in Table 5 (Jonas, 1985a). To find the true causes of corrosion, it is essential to analyze the local temperature, pressure, chemistry, moisture droplet flow, and stress conditions. These analyses are often neglected.

Table 5. Causes of Blade Failures in LP, IP, and HP Steam Turbines.

	Cause of Failure	LP (%)	IP (%)	HP (%)
1.	Unidentified/no reason given	38	27	33
2.	Stress corrosion, corrosion fatigue	24	6	8
3.	Design related	9	43	8
4.	System resonance	5	---	2
5.	Flow excitation	5	---	7
6.	Feedwater chemistry High carry-over from boiler Contaminated attemperation water	5	---	2
7.	Erosion	5	16	17
8.	Nozzle resonance	3	---	7
9.	Partial admission loading	2	---	8
10.	Water induction	2	6	4
11.	Other reasons given: Resonance due to manufacture-tolerances Pitting during storage and layup Wrong heat treatment (high yield strength) Riveting cracks in tenons	2	2	4

Root Causes

High stresses and marginal steam chemistry acting together are the most frequent root causes. Corrosion fatigue cracks are driven by cyclic stresses with high mean stress playing a large role. Figure 10 shows how fatigue strength is reduced at high mean stresses. It has been estimated that the corrosion fatigue limit for long LP turbine blades in the area of high mean stress is as low as 1 ksi (7 MPa). Rough surface finish and pitting often shorten the time to crack initiation.

Cyclic stresses are caused by turbine startups and shutdowns (low number of cycles, high cyclic stresses), by the turbine and blades ramping through critical speeds at which some components are in resonance (high amplitude, high frequency), and by over 15 causes of flow induced blade excitation during normal operation that include:

- Synchronous resonance of the blades at a harmonic of the unit running speed.
- Nonuniform flows.
- Blade vibration induced from a vibrating rotor or disc.
- Self-excitation such as flutter.
- Random excitation-resonance with adjacent blades.
- Shock waves in the transonic flow region and shock wave-condensation interaction.
- Bad blade design with wrong incidence flow angle and flow separation.

Elevated concentrations of steam impurities (particularly of chloride, sodium, and sulfate) and the resulting deposition and concentration by evaporation of moisture are underlying causes of corrosion fatigue. When feedwater, boiler water, and steam impurity levels exceed recommended limits, cycle chemistry can be a contributor or even the root cause. Poor shutdown and layup procedures are primary contributors to aggressive environments that can lead to pitting and corrosion fatigue. High steam sodium or cation conductivity may indicate conditions that can lead to rapid accumulation of deposits and concentrated liquid films on blade surfaces.

Solutions

The solutions to blade corrosion fatigue problems include:

- Design of blades that are not in resonance with running speed and its harmonic frequencies or with any of the excitation sources listed above.
- Design with friction damping.
- Elimination of the sources of excitation.
- Reduction of mean and alternating stresses by design (lower stress concentrations, etc.).
- Better materials, such as by avoiding high strength alloys, using materials with high material damping, or using titanium alloys.
- Improvement of steam chemistry.

Long-term actions for dealing with corrosion fatigue begin with economic and remaining life assessments. Depending upon the severity of the problem and the costs to eliminate it, some solutions may not be practical for all circumstances. The available prevention strategies fall into four main categories: redesigning the blade to reduce resonance, redesigning the blade or attachment to reduce stress levels, improving steam purity, and/or changing the material or surface (better surface finish, shot peening) of the blade.

Stress reduction options include:

- Changing the vibration resonance response of the blade by design modification (adding or reducing weight of the blade, changing to free standing, grouped or fully connected shrouded blades, moving tiewires or tenons, shroud segment integrally machined with the blade—no tenons, etc.).

- Changing the response of the blades by mixed tuning.
- Increasing the damping of the blades.
- Changing operating procedures; for example, avoiding off-design operation such as very low load, high backpressure operation (which can cause stall flutter), and changing rotational speed during startups.

Options to improve the turbine environment include:

- Controlling impurity ingress (reduce air inleakage, plug leaking condenser tubes, etc.).
- Changing unit operating procedures, particularly for shutdowns and startups.
- Control of boiler carryover by drum design and water chemistry.
- Optimizing or changing feedwater and boiler water treatment to reduce concentration of impurities in steam.

Another option to improve the environment at surfaces is to improve the surface finish of blading. Deposition and subsequent concentration of impurities are a function of blade surface finish (EPRI, 2001b), and this improvement may help slow the accumulation of impurities. Improving the continuous monitoring of steam chemistry (sodium, cation conductivity) will help to verify improvements in the environment.

If such changes are not sufficient, then changing to a more corrosion resistant material, such as a material with a higher chromium content or a titanium alloy, is generally recommended.

It should be noted that higher strength materials are often more susceptible to stress corrosion cracking. It has been shown that 403SS, with yield strength above ~90 ksi (620 MPa), becomes susceptible to SCC.

Pitting

Pitting can be a precursor to more extensive damage from CF and SCC, although extensive pitting of blades can also cause significant loss of stage efficiency by deteriorating the surface finish (EPRI, 2001b). Pitting is found in a wide range of components. It occurs most prevalently during shutdown when moisture condenses on equipment surfaces and as a result, it can be found in stages of the turbine that are dry during operation. However, it can also occur during operation, particularly in crevices (crevice corrosion).

In LP turbines, pitting is primarily found on the turbine blades and blade-disc attachments, particularly in the “salt zone” (Figure 14). There is little pitting on wet stages because corrosion impurities are washed away by the steam moisture. Pitting is frequently found in the blade tenon-shroud crevices because, once corrosive impurities enter, they cannot be removed. Titanium alloys are the most resistant to pitting corrosion, followed by duplex ferritic-austenitic stainless steels (Fe-26Cr-2Mo), precipitation hardened stainless steels (Fe-14Cr-1.6Mo) and 12%Cr steels.

Root Causes

Steam and deposit chemistries are the main causes of pitting, with chlorides and sulfates being the main corrodents. Copper and iron oxides accelerate pitting by providing the matrix that retains salts. Copper oxides also transport oxygen to the corrosion sites. Dissolved oxygen does not concentrate in the liquid films forming on blade surfaces during operation but does, however, accumulate in the liquid films and wet deposits that can form during unit shutdown if proper layup practices are not used. There have been cases of severe blade pitting requiring blade replacement on brand new rotors from which preservatives were stripped leaving them exposed to sea salt during prolonged erection periods.

Solutions

The first line of defense against pitting is controlling steam purity. This will improve the local environment produced during operation and decrease the amount of deposition. The chemistry guidelines established by an independent research and development firm (EPRI, 1986, 1994c, 1998b, 1998c, 2002a; Jonas, et al., 2000) particularly for cation conductivity, chloride, and sulfate, should be followed. There should be a layup protection of the LP turbines by dehumidified air, vapor phase inhibitors, or nitrogen.

After a steam chemistry upset, such as a large condenser leak, the turbine should be washed online or after a disassembly. Doing nothing may result in multimillion dollar corrosion damage requiring rotor replacement.

Flow-Accelerated Corrosion

Flow-accelerated corrosion of carbon and low-alloy steels in the steam path two-phase flow has been less widespread in fossil plants than in nuclear plants; however, it has occurred at some locations (EPRI, 1996; 1998a; Kleitz, 1994; Jonas, 1985b; Svoboda and Faber, 1984) such as:

- Wet steam extraction pipes and extraction slots.
- Exhaust hood and condenser neck structure.
- Casings.
- Rotor gland and other seal areas.
- Disc pressure balance holes.
- Rim and steeples of last row disc.
- Rotor shaft—last disc transition.
- Leaking horizontal joint.
- Transition between the stationary blades and the blade ring.

While most cases of flow-accelerated corrosion damage are slow to develop and are found during scheduled inspections, FAC of piping and turbine casing horizontal joints can lead to leaks and FAC of rotors and discs can initiate cracking.

Root Causes

Root causes of FAC in the turbine (EPRI, 1996, 1998a; Jonas, 1985b) include:

- Susceptible material: carbon steel or low-chromium steel.
- Locally high flow velocities and turbulence.
- High moisture content of the steam.
- Low levels of dissolved oxygen, excess oxygen scavenger.
- Low pH of moisture droplets.
- Water/steam impurities.

Solutions

It is recommended that a comprehensive FAC control program be implemented, including an evaluation of the most susceptible piping and other components (EPRI, 1996). Areas of local thinning need to be periodically inspected and repaired. Approaches to piping repair include replacement with low alloy steels, weld overlay, and plasma arc and flame spraying to protect susceptible surfaces. The material applied should have high chromium content. If a component is replaced, the material of the new component should contain some chromium. For example, carbon steel pipe should be replaced with 1.25 percent or higher chromium steel. Little can be done about changing the moisture concentration in fossil turbines. Steam chemistry improvements through better control of feedwater and boiler water chemistry, such as reduction of organic acids, could result in increase of pH of the early condensate and less FAC (EPRI, 1997b, 1997c, 1999).

Treatment of feedwater, such as maintaining high pH levels (above 9.6) and elevated oxygen concentrations, can also reduce FAC in the turbine.

Other Phenomena (Noncorrosion)

Although not specifically corrosion related, there are other problems that occur in steam turbines including: deposition on blade surfaces; water droplet erosion of wet stage blades; low cycle thermal fatigue of heavy high temperature sections of rotor, casing, and pipes; solid particle erosion of turbine inlets and valves; and water induction and water hammer.

Deposition on Blade Surfaces

Deposits are the result of impurities in the feedwater, boiler water, and attemperating water being carried over into the turbine (Jonas and Dooley, 1997; EPRI, 1997b, 2001b; Jonas, et al., 1993; Jonas, 1985d). All impurities are soluble in superheated and wet steam and their solubility depends on pressure and temperature. The steam leaving the steam generator is at the highest steam pressure and temperature in the cycle. As it passes through the turbine, the pressure and temperature decrease, the steam loses its ability to hold the impurities in solution, and the impurities precipitate and deposit on the turbine blades and elsewhere.

The main impurities found in turbine deposits are magnetite, sodium chloride, and silica. It takes only a few hours of a chemical upset, such as a major condenser leak or a boiler carryover event, to build up deposits, but it takes thousands of hours of operation with pure steam to remove them.

The impact of deposits on turbine performance is the most pronounced in the HP section. Performance loss depends on deposit thickness, their location (steam pressure), and the resulting surface roughness (EPRI 2001b). Deposits will change the basic profile of the nozzle partitions resulting in losses caused by changes in flow, energy distribution, and aerodynamic profiles, as well as by surface roughness effects. These changes can result in large megawatt and efficiency losses. With replacement power typically over $100/MWh and costing as much as $7000 per MWh in the summer of 1998, the savings from reducing this deposition can be very high.

In the LP turbine, deposits are often corrosive, they can change the resonant frequency of blades, increase the centrifugal load on blade shrouds and tenons and, in the transonic stages, they can influence the generation of shock waves.

Solutions—Optimization of cycle chemistry (Jonas, 1982, "Progress in...," 1981; EPRI, 1986, 1994c, 1998b, 1998c; 1985d, 2002a; Jonas, et al., 2000, 2007; ASME, 2002) is the easiest method for reducing impurity transport and deposition. The optimal cycle chemistry will result in reduced corrosion and minimized impurity transport. This is especially important if copper alloys are present in the system because the optimal feedwater pH for copper alloys and ferrous materials are not the same and the incorrect pH can result in high levels of iron or copper transport. Other methods for managing deposition on blade surfaces include:

- Specify good surface finishes (polished blades) on all new and replacement blades.
- Determine the effect of erosion and deposition on maximum MW and efficiency with a valves wide open (VWO) test. The data from several VWO tests can be compared to determine the rate of MW loss and MW versus chemistry and operation. This can be used to optimize the system.
- Turbine washing to reduce deposition and MW losses and improve efficiency. Both, a turbine wash of an assembled turbine and a wash of a disassembled rotor can be used to remove soluble deposits. To remove corrosive salt deposits, several days of washing may be needed. A wash is usually completed when the concentration of corrosive impurities, such as sodium and chloride, in the wash water is less than 50 ppb.

Water Droplet Erosion

In the last stages of the LP turbine, the steam expands to well below saturation conditions and a portion of the vapor condenses into liquid (EPRI, 2001b; Ryzenkov, 2000; Oryakhin, et al., 1984; Rezinskikh, et al., 1993; Sakamoto, et al., 1992; Povarov, et al., 1985; Heyman, 1970, 1979, 1992). Although the condensed droplets are very small (0.05 to 1 µm, 2 to 40 µin diameter), some of them are deposited onto surfaces of the stationary blades where they coalesce into films and migrate to the trailing edge. Here they are torn off by the steam flow in the form of large droplets (5 to 20 microns, 0.2 to 0.8 mils). These droplets accelerate under the forces of the steam acting on them and, when they are carried into the plane of rotation of the rotating blades, they have reached only a fraction of the steam velocity. As a result, the blades hit them with a velocity that is almost equal to the circumferential velocity of the blades, which can be as high as 640 m/s (2100 ft/s) in a fossil LP turbine. Water droplet erosion typically occurs in the last two to three rows of the LP turbines in fossil fired units. The damage is most common on the leading edge and tip of the blades and along the shroud.

In turbines operating at low load for long periods, such as cycling and peaking units, reversed flow of steam caused by windage and activation of hood spray can erode the trailing edges of blades. Thin trailing edges with erosion grooves can become fatigue or corrosion fatigue crack initiation sites. Less frequent erosion damage locations include LP turbine glands and seals, stationary blades, blade attachment sections of discs, disc flow holes (impulse design), and the LP rotor at the gland.

The effects of steam and early condensate chemistry on water droplet erosion are not known, but studies have found that NaCl in the droplets significantly reduces the incubation period for erosion. In addition, pH was found to have a strong impact on both the incubation period and the erosion rate. At higher pH, both the maximum and steady state erosion rates decrease while the incubation period increases (Ryzenkov, 2000; Povarov, et al., 1985).

Solutions—There are several options available for reducing the amount of damage from liquid droplet impact. There are two principal options: protection of the leading edge by a hard material and collection and drainage of moisture. Table 6 outlines these options.

Table 6. Long-Term Actions for Reducing Moisture Erosion on LP Turbine Blades.

Protection of Leading Edge
Shielding of susceptible locations, particularly the leading edge of the rotating blades, using another metal (Stellite, titanium, high carbon steel, etc.)
Localized hardening of the blade material by heat treatment
Weld repair, if erosion is not too severe and if cracks do not penetrate to the blade/shield interface
Erosion-resistant coatings
Design Options
Water extraction by cylinder belts or circumferential water catcher belts to pull moisture out of the last stages of LP turbines
Removal of water through suction slots made in hollow stationary blades
Extracting moisture between blade rows
Redirection of flow to modify geometry, reduce amount of liquid impacting surfaces, reduce impact velocity of droplets, or change impact angle to reduce normal component of impact velocity
Increased axial spacing between the stator/nozzle and rotor/rotating blades
Heated stationary blades
Provide a drain in the outer wall behind each nozzle

Turbine Inspection and Monitoring

Adequate turbine inspection methods are available to detect corrosion and deposition. These NDT methods include visual, magnetic particle, ultrasonic, dye penetrant, eddy current, and radiographic techniques. Modern turbine designs consider the accessibility of individual components by inspection probes.

Monitoring techniques include stress and vibration monitoring (i.e., vibration signature), temperature and flow measurement, and water and steam chemistry sampling and analysis. (Jonas, 1982, 1985d, 1986, 1994; EPRI, 1984b, 1994a, 1994c, 1997b, 1997c, 1998c, 1999, 2002a; Jonas, et al., 1993, 2000; Jonas and Syrett, 1987; Schleithoff, 1984; "Progress in...," 1981). An advanced expert system has been developed (EPRI, 1994c) for the use by station operators and chemists, which automatically determines the problems and recommends corrective actions. There are also monitoring methods for online diagnosis of the environments on turbine surfaces and corrosion (Jonas, 1994; EPRI, 1994a, 1997b, 1997c, 1999; Jonas, et al., 1993).

MISSING KNOWLEDGE

It is estimated by the author that 70 percent of knowledge to solve and prevent corrosion problems in steam turbines is available. The percentage of available knowledge for understanding the effects of stress and environment is much lower than that for solving the problems, about 40 percent. The knowledge that is missing or needs improvement includes:

- Threshold stress required to initiate SCC in blade attachments.
- Effects of steeple geometry (stress concentrations and size) on SCC and CF.
- Effects of overloads during heater box and overspeed tests on stress redistribution and SCC in steeples, blade roots, and disc keyways.
- Effectiveness of grinding out SCC and CF cracks as a corrective measure.
- Effects of organic water treatment chemicals, and organic impurities on SCC, CF, and pitting and composition of water droplets.
- Effects of electrical charges carried by water droplets on corrosion.
- Effects of galvanic coupling of dissimilar materials, such as the blade-steeple, on corrosion.
- Effects of residues of preservatives and Loctite™ on SCC, CF, and pitting of blade attachments.
- Effects of blade trailing edge erosion on cracking.
- Accelerated stress corrosion testing.
- Effects of variable amplitude loading on CF crack initiation and propagation.
- Effects of water droplet pH and composition on erosion and how to predict erosion.
- Effects of shot peening to reduce stresses and SCC of blade roots and disc steeples.
- Understanding of the basic mechanisms of stress corrosion, corrosion fatigue, fatigue, and stress induced pitting.

CASE HISTORIES

Stress Corrosion Cracking in Finger-Style Dovetails

Unit: The station consists of three 805 MW, once-through boiler, supercritical, coal-fired units that went into operation between 1974 and 1976. Each of the three units has two LP turbines (LPA and LPB).

Problem: In 1995, in Unit 1, a blade failed in the L-1 row at a tiewire hole of the leading blade of a four-blade group (Nowak, 1997; Kilroy, et al., 1997). Three damaged groups of blades were removed for replacement. A wet fluorescent magnetic particle examination of the finger-style disc attachments found hundreds of crack-like indications, which were later identified as SCC. Cracks ran both axially and radially, and were deep (Figure 25).

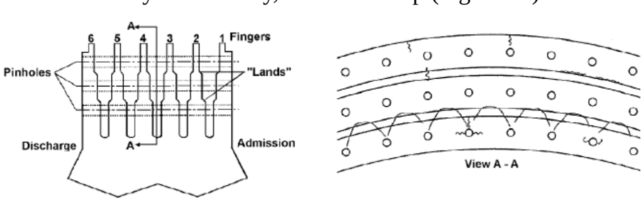

Figure 25. Locations in Finger and Pin Attachments Where SCC Has Been Found. (Courtesy of EPRI, 1997)

Inspection: Inspection procedures and the acceptance criteria that would be applied were developed before the outage. Eventually NDE inspection found some damage in each of the 12 ends of all six rotors. Severe cracking was found in all four-rotor ends in Unit 2 and in Unit 3 on both ends of LPB. Next in severity were both ends of Unit 1 LPB and Unit 3 LPA; with a few indications in Unit 1 LPA. In the heavily cracked rotors, damage was most severe in Fingers 3, 4, and 5 with little or no cracking in Fingers 1 or 6. Cracking was evenly distributed between admission and discharge sides in Fingers 3 and 4 with somewhat more cracking on the admission side in Finger 5.

Results of metallurgical analysis: A metallurgical evaluation confirmed the presence of extensive pitting. Cracks were found to be intergranular, highly branched, and oxide-filled. The metallurgical examination was unable to detect the presence of specific contaminants on the fracture surface. Sampling of deposits, which had occurred elsewhere in the cycle (crossover piping, bucket pins, and bucket fingers) during prior outages, had found indications of sodium, sulfur, and chloride and sodium hydroxide was found by x-ray diffraction in crossover piping.

Analysis of samples from two rotors showed that the chemical composition was within the specification for ASTM A470 Class 7 material. Tensile strength averaged 126.5 ksi (870 MPa) for the two specimens; yield averaged 112.5 ksi (775 MPa).

Review of cycle chemistry: Several cycle chemistry changes had been made over time in response to events such as improved technology and information, and upsets caused by condenser tube leaks, demineralizer breaks, and variations in boiler water makeup. The main water chemistry problem was operation with morpholine, which resulted in poor condensate polisher performance and high concentrations of sodium hydroxide in feedwater and steam. A heavy deposit of sodium hydroxide was found in the crossover piping. The unit had been changed to oxygenated treatment about the time of the discovery of the stress corrosion cracks, which has since resulted in better water and steam purity.

Results of stress analysis: A finite element stress analysis showed that Fingers 3, 4, and 5 of the group were the most highly stressed. The maximum equivalent elastic stresses around the pin holes were ~222 ksi (1530 MPa), ~114 ksi (786 MPa) at the inner land, and ~89 ksi (614 MPa) at the outer land (closer to disc outer diameter [OD]). The differences between inner and outer land stresses agreed with the observation that field cracking was more severe at the inner land. However, no SCC was discovered in the flat portion of the disc fingers around the holes, where the stress was nearly twice as high.

Closer examination found that the flat surface near the pinholes did not show cracks nucleating from the bottom of the pits, whereas intergranular cracks appeared in the pits along the ledge where the pits were linked to form continual flaws.

Root causes: There were two root causes of this massive problem: high design stresses and improper feedwater chemistry using morpholine, which resulted in the presence of NaOH and other impurities in steam. One can also speculate about the contributions of the local stress concentration, poor surface finish, and residual machining stresses.

Economic analysis: An economic analysis was performed and the costs considered included: replacement of rotors in-kind, replacement with an improved rotor steam path that would improve unit heat rate by 1.2 percent, rotor weld repair, outage duration costs, performance changes, reduced generation capacity from pressure plates, fuel pricing, and replacement energy costs.

Actions: As a temporary fix, the affected blade rows were removed and nine pressure plates were installed out of the 12 possible locations. A pressure plate is a temporary device that provides a pressure drop when installed as a replacement for a removed blade row. A decision was made to purchase two new fully bladed rotors and to refurbish the existing rotors. For Unit 1, new rotors were purchased from the original equipment manufacturer (OEM). The two LP rotors removed from Unit 1 were weld repaired using 12 percent chromium material applied with a submerged arc weld process, and installed in Unit 3. Material testing and analysis were used to determine the expected lifetime of the refurbished parts against damage by SCC, and both high- and low-cycle fatigue. Turbine and crossover pipes were cleaned to remove deposits.

Massive SCC of Disc Rim—Supercritical Once-Through Unit after Only Five Years of Service

Problem: Stress corrosion cracking of the L-1 stage disc was discovered during routine inspection (Figure 26).

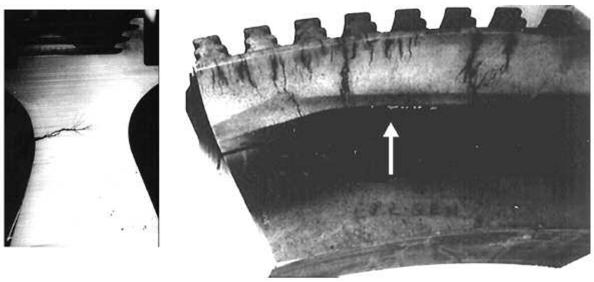

Figure 26. Massive SCC of L-1 Disc Caused by High Concentration of NaOH in Steam.

Root cause: The SCC was caused by poor performance of the condensate polishers that operated in H-OH form through ammonia breakthrough when they released Na^+. The sodium reacted with water forming NaOH and deposited in the turbine.

Actions: Rotor replaced and operation of condensate polishers and monitoring was improved.

Stress Corrosion Cracking of Bolted-on Discs in One Type of LP Turbine

Problem: In the effort to accommodate longer L-0 blades, one type of LP turbine was originally designed with the bolted-on last disc made of NiCrMoV low-alloy steel and heat treated to a yield strength of up to 175 ksi (1200 MPa). This steel was found to be susceptible to SCC.

Root cause: The root cause of this problem was design with a high strength material that is very susceptible to SCC.

Solution: All of these discs in many power plants had to be replaced with a lower strength material because of the danger of SCC failures in all types of steam environments.

Corrosion Fatigue of a Blade Airfoil

Unit: A 400 MW reheat unit with a once-through boiler, seawater cooling, and mixed bed condensate polishers.

Problem: During a three-month period, condenser cooling water leakage occurred periodically. Cation conductivity in the condensate and feedwater increased up to 2 µS/cm for about 30 to 60 minutes per day. At the end of the three-month period, vibration was detected in the LP turbine (EPRI, 1998a)

Damage: The turbine was opened and five broken freestanding L-2 rotating blades were found. According to the turbine design data, the broken blades were in the phase transition zone. The blades were broken at the transition between reddish deposits at the blade foot and clean metal in the upper part of the blades (phase transition on the blade). A laboratory investigation found chloride and sodium at the crack site and confirmed corrosion fatigue as the underlying mechanism. A calculation of vibration frequencies did not show abnormal conditions.

Root cause: Improper water chemistry conditions caused by the condenser tube leak.

Actions: The broken blades were replaced, the condenser leak was repaired, and a dampening (lacing) wire was introduced into the blade design. By doing so, both the environmental and stress contributors were reduced.

Corrosion Fatigue of Numerous Modifications of L-1 Blades

Problem: One type of LP turbine experienced corrosion fatigue failures of the L-1 blade airfoil, which was modified and redesigned over 10 times. Fatigue failures occurred in periods ranging from six weeks to over 10 years of operation. The presence of chloride in the blade deposits at concentrations above 0.25 percent caused pitting, which accelerated crack initiation. In one case, new 16 inch (40 cm) blades were forged in two dies and most of the blades forged in one of the dies (but none from the other die) failed within about six weeks.

Root cause: The root cause of this fast CF failure was an off-design blade geometry caused by wrong die dimensions, which brought these blades into resonance. The failure acceleration was caused by corrosive impurities in steam, mainly chloride.

Actions: Redesigned, better tuned blades were installed and improved control of water and steam chemistry was initiated.

Massive Pitting of a Turbine (HP, IP, and LP) after Brackish Water Ingress

Problem: A separation of the welded end of the condensate sparger caused breakage of condenser tubes and ingress of brackish water into a once-through boiler cycle. Because of the poor reliability of the water chemistry instrumentation, the instrument readings were ignored and the trouble was noticed after there was almost no flow through the superheater because of heavy deposits. The turbine with sea salt deposits was left assembled in the high humidity environment and was only opened 11 days after the condenser tube failure. It was found that the whole turbine was severely rusted and pitted and it was eventually replaced.

Mixed bed condensate polishers were not able to protect the cycle against the massive ingress of brackish water. They were exhausted within a few minutes.

Root cause: The root cause of the impurity ingress was a failure of the condensate sparger. Poor water chemistry monitoring and control and the long delay in beginning turbine damage assessment and cleaning significantly contributed to the amount of damage caused.

Actions: The rotors were replaced and new chemistry monitoring instrumentation was installed.

L-0 Blade Corrosion Fatigue Cracking Caused by Trailing Edge Erosion

Problem: After 14 to 18 years of service of one type of 400 MW turbine, there were five cases of L-0 33.5 inch (85 cm) long shrouded blade failures about 5 inches (12.7 cm) below the tip. The CF cracks originated at the eroded and thinned trailing edge. When the blade tips separated, the blade fragments had such kinetic energy that they penetrated over 2 inches (5 cm) of carbon steel condenser struts. The blade material was martensitic 12%Cr stainless steel with a Brinell hardness of ~345. All affected units were similar drum boiler units, some on all volatile treatment (AVT) and some on phosphate treatment. Steam chemistry in the affected units was good and did not play a role in the rate of erosion or cracking.

Root cause: Erosion caused by frequent operation at low load with the hood sprays on and reversed steam flow, lack of proper early inspection, and blade design with thin trailing edge.

Actions: Heavily eroded and cracked blades were replaced, shallow erosion damage was polished, and similar turbines were inspected for damage.

Stress Corrosion Cracking of Dovetail Pins

Problem: A dovetail pin, which penetrates both the rotating blade and the wheel dovetails, holds a bucket in place on the wheel of a rotor. In many plants during the 1970s and earlier, dovetail pins had suffered stress corrosion cracking, although no lost blades had resulted. The material originally used for the dovetail pins was similar to ASTM A681 Grade H-11 tool steel, with a chemistry of Fe-5.0Cr-1.Mo-0.5V-0.4C at a strength level of 250 to 280 ksi

(1715 to 1920 MPa). This material is still used in rare cases where the highest strength is required.

Root cause: Use of high strength material, which is susceptible to SCC, combined with high bending stresses.

Actions: The approach to solving the cracking problem was twofold: changing the material chemistry and strength and using steel ball shot peening to impart a compressive layer to the surface of the finished pins. The new high strength material is 5CrMoV low alloy steel at a strength level of 240 to 270 ksi (1645 to 1850 MPa). For lower stress applications, a new 1CrMoV low alloy steel with a strength of (170 to 200 ksi) is used.

Results: No cracking has been observed in dovetail pins since the change in materials and the introduction of the shot peening practice.

Turbine Destruction—Sticking Valves

Problem: After only 16 hours of operation of a new 6 MW steam turbine installed in a fertilizer plant, an accidental disconnect of the electrical load on the generator led to a destructive overspeed. The overspeed occurred because high boiler carryover of boiler water treatment chemicals, including polymeric dispersant, introduced these chemicals into the bushings of all turbine control valves, gluing the valves stuck in the open position.

Root cause: Poor control of boiler operation (drum level) together with the use of the polymeric dispersant that, after evaporation of water, becomes a strong adhesive. Controls of the electric generator allowed accidental disconnect.

Actions: New turbine generator installed, boiler and generator controls fixed, turbine valves reused after dissolution of the bushing deposits in hot water.

CONCLUSIONS

• Steam turbines can be a very reliable equipment with life over 30 years and overhaul approximately every 10 years. However, about 5 percent of the industrial and utility turbines experience corrosion and deposition problems. Mostly due to LP blade and blade attachment (disc rim) corrosion fatigue or stress corrosion failures.

• The root causes of the blade and disc failures include design with high stresses, bad steam chemistry, and use of high strength materials.

• Other steam turbine problems include: low cycle thermal fatigue, pitting during unprotected layup and operation, loss of MW/HP and efficiency due to deposits, water droplet erosion, flow accelerated corrosion, solid particle erosion by magnetite particles exfoliated from superheater, turbine destructive over speed caused by the control valves stuck open because of deposits in the bushings, and water induction-water hammer.

• All the problems are well understood, detectable, and preventable. Monitoring, inspection, and defects evaluation methods are available. These methods include design reviews and audits of operation and maintenance, NDT, life prediction, vibration monitoring, vibration signature analysis, water, steam, and deposit chemistry monitoring and analysis, valve exercise, and control of superheater temperatures.

• Steam cycle design and operation influences turbine problems by causing high steady and vibratory stresses, by thermal stresses related to load and temperature control, and by water and steam purity and boiler carryover.

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