Steam turbine corrosion

Otakar Jonas

The cost of the US utility and industrial turbine corrosion is estimated at about $700 million/year. Main problems include corrosion fatigue of fossil turbine blades, stress corrosion of discs, erosion-corrosion of wet steam piping, and pitting and stress corrosion of other components. Failure statistics and recent research are revealing correlations to the material, environmental, and design parameters which need all be considered in failure analysis, redesign, new design, and steam chemistry control. Interrelations and interactions between the mechanical and thermodynamic design, material properties, and steam and deposit chemistry are discussed and recommendations and corrosion design rules and requirements pertinent to these three components of turbine corrosion are given.

Introduction

STEAM TURBINES (EXCLUDING CONTROLS) CONTRIBUTED about 6.7% to more than 9000 forced outages in US utility units between 1971 and 1980 (Table 1). These outages cost the utilities $92,575 GWh, and outages caused by corrosion were a major part of it. A survey of about 500 utility turbines larger than 100 MW shows that the typical yearly frequency of corrosion failures is between 1 and 5% of operating turbines (Figure 1). Considering that it takes, on the average, about 4 years for corrosion to lead to a failure, about 25% of operating large turbines are now under attack. An American Society of Mechanical Engineers survey of industrial turbines found a similar degree of corrosion and deposit problems (Figure 2).

Blade failures are most frequent (in fossil turbines) in the last minus one row of (L-1R), and Figure 3 blade pitting and cracking is more frequent in once-through boiler units (all volatile treatment-VT and condensate polishers) than in drum boiler units. West German, UK, and Japanese statistics indicate low incidence of blade failures. A recent survey of 494 US utility units reports that 167 units (34%) experienced blade failures between 1970 and 1981. In 1980, 1981, and 1982, the failure rate was about 4.7%.

Stress corrosion of LP turbine discs is for each type of turbine and each location on a disc specifically distributed, indicating a correlation with surface temperature and steam conditions most likely related to impurity concentration, and with yield strength, stress, and operating temperature. Another interesting (often neglected) feature of the US disc cracking experience is that on a disc keyway develops cracks; sometimes, there are cracks in the bore and none in the keyways, and the rim cracking is often confined to only a segment of the circumference. Turbines operated in West Germany and Japan, even US-designed, are free of these problems.

US experience is rather unique as compared to other industrial countries. The differences include:

1. Much higher number of corrosion failures in the US
2. Most decentralized, nonuniform water chemistry practices specific to individual units and utilities
3. Low recognition and understanding of effects of water chemistry
4. Low recognition of effects of system design and material selection on corrosion
5. Late recognition of effects of blade and disc design on turbine component corrosion

We should consider the differences between the US and foreign practices in our analysis of turbine corrosion.

After many years of a search for solutions, improvements of water and steam chemistry and design changes are starting to produce them.

There will continue to be corrosion failures, even with the improved design and operation, because many turbine components (blades, discs, rotors) are already so corroded (pitted) that their corrosion strength is reduced beyond repair, and it is only a question of small additional corrosion or mechanical damage for them to fail.

It has been estimated that out of the total US yearly cost of corrosion of about $70 billion, 15% corrosion in utility steam systems costs about $1.5 billion/year. The cost of corrosion of US nuclear turbines has been estimated at about $200 million a year. The cost of blade corrosion (estimated from data in Reference 9) at about $300 million a year. Adding the estimated costs of bolt, bellows, and piping corrosion, the total US cost of the utility turbine corrosion is about $600 million a year.

Information on industrial and marine turbines is limited, but considering the results of the survey of industrial turbines and the fact that there are many more industrial turbines than the utility ones, the cost is likely to be over $100 million a year.

Replacement power keeps escalating, and can be as high as $100 per MWh or $1 million a day for a large utility unit. The cost of replacement power far exceeds the cost of replacement parts and can be up to two orders of magnitude higher. Average cost of replacement blades ranged from $135,000 to $559,000 per unit per year, average cost of downtime from $5.3 to $10.8 million per unit per year.

This article is an attempt to describe and document our current understanding of corrosion of steam turbine components and to give a balanced view of the effects of material properties, environment, and design. Major results of corrosion and chemical studies are considered throughout and applied in conclusions and recommendations.

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TABLE 1 — Top 18 causes of forced-full and partial outages, 1971-80, ranked in order of lost GWh. Also showing total outage charges against all cause codes, including the top 18

<table>
<thead>
<tr>
<th>Code</th>
<th>Item</th>
<th>Forced Full</th>
<th></th>
<th>Forced partial</th>
<th></th>
<th>Total</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>No. GWh</td>
<td>No. GWh</td>
<td>No. GWh</td>
<td>No. GWh</td>
<td>No. GWh</td>
<td>No. GWh</td>
</tr>
<tr>
<td>101</td>
<td>Waterwalls</td>
<td>14,540</td>
<td>291,101</td>
<td>2,022</td>
<td>16,282</td>
<td>16,562</td>
<td>307,383</td>
</tr>
<tr>
<td>103</td>
<td>Superheater</td>
<td>9,922</td>
<td>142,677</td>
<td>1,873</td>
<td>5,168</td>
<td>11,795</td>
<td>147,844</td>
</tr>
<tr>
<td>121</td>
<td>Pulverizer</td>
<td>502</td>
<td>4,941</td>
<td>74,105</td>
<td>89,443</td>
<td>74,607</td>
<td>94,384</td>
</tr>
<tr>
<td>905+</td>
<td>Boiler feed pump</td>
<td>1,700</td>
<td>21,219</td>
<td>14,210</td>
<td>70,003</td>
<td>15,910</td>
<td>91,222</td>
</tr>
<tr>
<td>922</td>
<td></td>
<td>100</td>
<td>77,839</td>
<td>6,589</td>
<td>13,111</td>
<td>10,452</td>
<td>90,950</td>
</tr>
<tr>
<td>104</td>
<td>Reheater - first</td>
<td>80,997</td>
<td>785</td>
<td>3,071</td>
<td>4,729</td>
<td>84,068</td>
<td>100,783</td>
</tr>
<tr>
<td>629</td>
<td>Vibration of T-G</td>
<td>2,750</td>
<td>71,074</td>
<td>2,253</td>
<td>9,709</td>
<td>5,011</td>
<td>90,783</td>
</tr>
<tr>
<td>901</td>
<td>Buckets or blades</td>
<td>187</td>
<td>53,324</td>
<td>1,747</td>
<td>17,979</td>
<td>1,934</td>
<td>71,303</td>
</tr>
<tr>
<td>109</td>
<td>F.W. heater leak</td>
<td>1,090</td>
<td>16,885</td>
<td>11,544</td>
<td>47,217</td>
<td>12,834</td>
<td>64,102</td>
</tr>
<tr>
<td>106</td>
<td>Economizer</td>
<td>4,783</td>
<td>59,860</td>
<td>564</td>
<td>3,142</td>
<td>5,347</td>
<td>63,002</td>
</tr>
<tr>
<td>109</td>
<td>I.D. fan</td>
<td>977</td>
<td>14,548</td>
<td>12,184</td>
<td>38,078</td>
<td>13,161</td>
<td>52,626</td>
</tr>
<tr>
<td>110</td>
<td>F.D. fan</td>
<td>785</td>
<td>10,420</td>
<td>9,455</td>
<td>38,078</td>
<td>10,240</td>
<td>49,098</td>
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<tr>
<td>631</td>
<td>Lube oil syst., T-G</td>
<td>911</td>
<td>41,782</td>
<td>1,099</td>
<td>4,786</td>
<td>2,010</td>
<td>46,568</td>
</tr>
<tr>
<td>102</td>
<td>Generating tubes</td>
<td>1,691</td>
<td>42,448</td>
<td>409</td>
<td>1,625</td>
<td>2,100</td>
<td>44,074</td>
</tr>
<tr>
<td>706</td>
<td>Stator windings, etc.</td>
<td>187</td>
<td>37,767</td>
<td>226</td>
<td>2,910</td>
<td>413</td>
<td>40,677</td>
</tr>
<tr>
<td>136</td>
<td>Furnace slagging</td>
<td>549</td>
<td>17,684</td>
<td>14,487</td>
<td>22,835</td>
<td>16,036</td>
<td>40,529</td>
</tr>
<tr>
<td>600</td>
<td>Main turbine, general</td>
<td>999</td>
<td>37,399</td>
<td>1,101</td>
<td>3,090</td>
<td>2,100</td>
<td>40,469</td>
</tr>
<tr>
<td>622</td>
<td>Control, turbine &amp; reheat stop valves</td>
<td>1,937</td>
<td>26,285</td>
<td>2,266</td>
<td>9,251</td>
<td>4,205</td>
<td>37,537</td>
</tr>
</tbody>
</table>

Total of all forced outages for the decade

<table>
<thead>
<tr>
<th></th>
<th>Forced Full GWh</th>
<th>Forced partial GWh</th>
<th>Total GWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>All fossil codes</td>
<td>92,223</td>
<td>1,681,331</td>
<td>338,546</td>
</tr>
<tr>
<td>All nuclear codes</td>
<td>4,178</td>
<td>313,457</td>
<td>14,645</td>
</tr>
</tbody>
</table>

FIGURE 1 — Statistics of large turbine corrosion failures.²

FIGURE 2 — Corrosion and deposit problems in US industrial turbines.³

Major corrosion problems

Corrosion fatigue (CF), stress corrosion cracking (SCC), pitting, and erosion-corrosion are the main corrosion mechanisms acting in steam turbines. A list of major problems is shown in Table 2. Pitting and corrosion fatigue of turbine blades and stress corrosion of discs are currently the two costliest problems. Much research activity centers around these two problems,⁴⁻¹⁴,¹⁷,³⁸ and progress is being made both in operation (better steam chemistry) and design (lower stresses, no crevices, limit on maximum strength to reduce susceptibility to SCC).

Materials Performance
TABLE 2 — Turbine components that have experienced corrosion

<table>
<thead>
<tr>
<th>Component</th>
<th>Material</th>
<th>Corrosion mechanisms(1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rotor</td>
<td>CrMoV, NiCrMoV low alloy steel forging</td>
<td>P, SCC, CF, E</td>
</tr>
<tr>
<td>Shell</td>
<td>CrMoV low alloy steel castings, C-steel</td>
<td>SCC, CF, E</td>
</tr>
<tr>
<td>Discs-bucket wheels</td>
<td>NiCrMoV, CrMoV, NiCrMo low alloy steel forging</td>
<td>P, SCC, CF, CE</td>
</tr>
<tr>
<td>Dovetail pins</td>
<td>CrMo low alloy steel</td>
<td>SCC</td>
</tr>
<tr>
<td>Bucket tie wires</td>
<td>12Cr stainless steels (ferritic &amp; martensitic)</td>
<td>SCC, P, CF</td>
</tr>
<tr>
<td>Shrouds-bucket covers</td>
<td>12Cr stainless steels, 17-4 PH</td>
<td>P, SCC</td>
</tr>
<tr>
<td>Blades-buckets</td>
<td>12Cr stainless steels, 17-4 PH</td>
<td>P, CF, SCC, E</td>
</tr>
<tr>
<td>Stationary blades</td>
<td>304 SS</td>
<td>SCC, SCC-LCF</td>
</tr>
<tr>
<td>Expansion bellows</td>
<td>AISI 321, 304, austenitic stainless steel, Inconel 600</td>
<td>SCC, SCC-LCF</td>
</tr>
<tr>
<td>Erosion shields</td>
<td>Stellite type 68-weld deposited or soldered</td>
<td>SCC, E</td>
</tr>
<tr>
<td>Boitling</td>
<td>Incoloy 901, Refractalloy 25, Pyromet 860</td>
<td>SCC, SCC-LCF</td>
</tr>
<tr>
<td>Wet steam piping</td>
<td>Carbon steel</td>
<td>CE</td>
</tr>
</tbody>
</table>


There is a pronounced thermodynamic effect in both component failures. They are most frequent where the metal surface temperature is slightly above the saturation temperature of steam. This is for the low pressure fossil turbines usually on the LP-1R blades. It is one of the reasons why the L-1R blades have a higher failure rate than any other blade row (Figure 3). Another reason for the high L-1R blade failure rate could be the effects of transonic flow and vibratory stresses and changing temperatures resulting from an interaction of the shock wave with the Wilson line (periodic destruction of the Wilson line).19

Causes of blade failures are listed in Table 3, modified from Reference 9. There are several possible corrosion damage mechanisms and many factors affecting discs and rotors. They are listed for the observed crack locations (Figure 4) in Table 4. To find the true causes of corrosion, it is essential to analyze the local temperature, pressure, chemistry, moisture velocity, and stress conditions. These analyses are often neglected.

Erosion-corrosion of the carbon steel wet steam piping has been of concern in Europe, but is only slowly being recognized as a problem in the US. It is more pronounced in carbon steel pipes with high velocity turbulent flow and low pH moisture containing a high concentration of carbon dioxide or other acid forming anions.20-25 In the US, pipe wall thickness in several power water reactor (PWR) units has been reduced significantly (up to perforation in at least one case). Corrosion of other turbine parts (Table 2) is caused by one or more of the same causes as described above. There is a strong SCC-low cycle fatigue interaction in many turbine materials (well recognized in piping) which may be important in stationary blade, bolt, expansion bellows, and turbine cylinder failures. Highest frequency of turbine botting failures has been in HP and IP cylinders and nozzle blocks. Stress corrosion cracking of expansion bellows used to be a problem in fossil units with high concentration of sodium hydroxide (IP-LP pipes).26

Materials

There is little worldwide variation in materials 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, and control of inclusions and trace elements are being tested for discs and rotors. In addition to the materials listed in Table 2, carbon steel is used for LP shells, CrMo steels and austenitic stainless steels for HP piping, and miscellaneous other materials for other components.

TABLE 3 — Causes of blade failures

<table>
<thead>
<tr>
<th>Cause of failure</th>
<th>LP</th>
<th>IP</th>
<th>HP</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Unidentified/no reason given</td>
<td>38%</td>
<td>27%</td>
<td>33%</td>
</tr>
<tr>
<td>2. Stress corrosion, corrosion fatigue</td>
<td>24%</td>
<td>6%</td>
<td>8%</td>
</tr>
<tr>
<td>3. Design related</td>
<td>9%</td>
<td>43%</td>
<td>8%</td>
</tr>
<tr>
<td>4. System resonance</td>
<td>5%</td>
<td>—</td>
<td>2%</td>
</tr>
<tr>
<td>5. Water excitation</td>
<td>5%</td>
<td>—</td>
<td>7%</td>
</tr>
<tr>
<td>6. Feedwater chemistry</td>
<td>5%</td>
<td>—</td>
<td>2%</td>
</tr>
<tr>
<td>6’. High carryover from boiler</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6”* Contaminated attemperation water</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7. Erosion</td>
<td>5%</td>
<td>16%</td>
<td>17%</td>
</tr>
<tr>
<td>8. Nozzle resonance</td>
<td>3%</td>
<td>—</td>
<td>7%</td>
</tr>
<tr>
<td>9. Partial admission loading</td>
<td>2%</td>
<td>—</td>
<td>8%</td>
</tr>
<tr>
<td>10. Water induction</td>
<td>2%</td>
<td>6%</td>
<td>4%</td>
</tr>
<tr>
<td>11. Other reasons given</td>
<td>2%</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>12. Resonance due to manufacture-tolerances</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13. Pitting during storage and layup</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>14. Wrong heat treatment (high YS)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. Riveting cracks in tenons</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Percentages are from Reference 9.

Considering the typical 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 conditions in environments such as caustic, chlorides, hydrogen, carbonate-bicarbonate, carbonate-CO₂, acids, and at higher stresses and strength levels to pure water and steam.

No turbine can permanently tolerate concentrated caustic, sodium chloride, or acids. Under such conditions, disc and rotor materials would crack by SCC in a few hundred hours at stresses as low as 10% of the yield strength. Blades made of 12Cr may tolerate NaOH, but would pit and crack by corrosion fatigue at low vibratory stresses in many other corrodents. With high concentration of impurities for a long time, there would always be a weak link in the turbine or within the
### TABLE 4 — Disc and rotor crack locations and possible corrosion mechanisms and causes

<table>
<thead>
<tr>
<th>Location</th>
<th>Possible mechanism and causes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disc keyways</td>
<td>SCC, high stress, poor surface finish, crevice, corrosive cutting fluid (Cl⁻), MoS₂, steam-borne impurities, salt zone</td>
</tr>
<tr>
<td>Flow-through keyways</td>
<td>Add erosion-corrosion, hot surfaces in wet steam</td>
</tr>
<tr>
<td>Disc bore</td>
<td>SCC, marginal stress, crevice, MoS₂, salt zone, pitting, fretting</td>
</tr>
<tr>
<td>Disc face</td>
<td>SCC, hot surface in wet steam, steam-borne impurities, marginal stress</td>
</tr>
<tr>
<td>Disc rim</td>
<td>SCC, CF, erosion-corrosion initiation, hot surface in wet steam, in salt zone, high stress, steam expansion through blade root-steeple crevice and seals, galvanic and crevice effects</td>
</tr>
<tr>
<td>Steeples</td>
<td>CF, SCC, erosion-corrosion initiation, marginal steady and vibratory stress, steam-borne impurities, hot surface in wet steam, adiabatic steam expansion through seals and crevices, salt zone, galvanic effects</td>
</tr>
<tr>
<td>Rotor near glands</td>
<td>Erosion-corrosion initiation, CF, condensing gland steam, salt zone, air in gland steam or water</td>
</tr>
<tr>
<td>All</td>
<td>Pitting during storage, rupture, and unprotected layup</td>
</tr>
</tbody>
</table>

![FIGURE 4 — Crack locations in turbine discs with probable impurity concentration and corrosion mechanisms and corroders.](image)

![FIGURE 5 — Potential-pH diagram for iron in hot aqueous solutions.](image)

![FIGURE 6 — Corrosion rate of copper alloys and carbon steel vs pH.](image)

Power cycle which would fail prematurely. While we could use titanium for blades and tolerate most of the impurities (except hydroxides), more corrosion resistant materials for the large forgings of rotors and discs are hard to find. The cost, forgeability, banding of alloying elements and impurities, and other problems make it difficult. Plating and surface coatings appear to be only marginal temporary solutions.²⁷

Aside from the susceptibility to localized corrosion in concentrated impurities, low alloy and carbon steels used extensively in steam turbines have a rather narrow range of passivity (see the modified Pourbaix diagram in Figure 5²⁸). This makes these steels vulnerable to pH excursions and consequent pitting and other forms of localized corrosion during the operation and layup. In chloride solutions, the acid corrosion boundary in Figure 5 shifts to the right, and the pH region for passivation becomes even narrower.

Where copper alloys are used in the systems using all-volatile water treatment, use of high pH and effective neutralization of acids are restricted by the need to minimize corrosion and transport of copper (Figure 6).
The above material-corrosion restrictions, system chemistry, and ecological and other requirements lead to the conclusion that the concentration of corrodes on turbine surfaces must be kept low. Unless a local concentration mechanism cannot be avoided (such as in heated crevices and where there is evaporation of moisture on hot surfaces), turbines should be designed against corrosion in water and steam, within the compositions given by steam purity specifications\textsuperscript{16,12,20,35} and with the highest possible margin against occasional short excursions of impurity concentrations. This logic has been described in Reference 5 and the environment selected as the base was water (at temperature) with impurity concentrations at 100 times the limits for normal operation (representing a "reasonable" environment and accounting for some concentration in surface oxides and crevices). Using the recommendation in Reference 29, it could have 2 ppm NaCl, 5 ppm SiO\textsubscript{2}, 2 ppm Na\textsubscript{2}SO\textsubscript{4}, 2 ppm NaOH, and proper pH and oxygen concentration pertinent to the power system water chemistry and location within the turbine.

Corrosion data from the above environments should be usable by a designer. They should provide allowable steady and vibratory stresses and stress intensities for defined design life or inspection intervals. It is suggested that the SCC data include $\sigma$\textsubscript{SCC} and $K_{SCC}$, 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 through 9 for the NiCrMoV disc material and in Figure 10 for 12% Cr blade steel. Properly heat treated 12% Cr blade steel (yield strength \approx 600 MPa or 85 ksi) is not susceptible to SCC, and stress corrosion data is not needed.

The difficulty in obtaining the suggested data is the long time needed for testing. There does not seem to be any universal accelerated test or environment. The $K_{SCC}$ test in hydrogen sulfide gives a reasonable approximation for low alloy steels, and ultrasonic fatigue gives usable data to a high number of cycles needed for turbine design.

As a rule of thumb, the elasticity limit at temperature (usually between 0.4 and 0.6 of the 0.2% yield strength) can be used as a good $\sigma$\textsubscript{SCC} estimate for reasonable, not very corrosive environments for low and medium strength materials. This is consistent with the oxide film rupture or strain induced cracking theory of SCC\textsuperscript{37,38}.

Environment

The corrosiveness of the steam turbine environment is caused by one or more of the following: (1) concentration of impurities from low ppb levels to percent and formation of concentrated aqueous solutions; (2) insufficient pH control (in both acid and alkaline regions) by water treatment additives such as ammonia; and (3) high velocity, high turbulence, suppressed pH moisture.

The situation is generalized in Figure 11, which is a Mollier diagram with a turbine steam expansion line and thermodynamic regions of impurity concentrations (\textit{NaOH}, salts) and resulting corrosion. Note that hot turbine surfaces (in relation to steam saturation temperature) can shift from the wet steam region into the salt zone and above. This can be the reason why SCC occurs in the wet steam regions\textsuperscript{10,14,39} and it is the reason for our recommendation to consider local surface temperatures in design and failure analysis. 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).\textsuperscript{3,9,40}

The impurity concentration mechanisms include: (1) precipitation from superheated steam and deposition, (2) evaporation and drying of moisture on hot surfaces, (3) concentration in oxides, and (4) adsorption of nonhomogeneous nucleation of concentrated droplets and crystals on surfaces. None of these mechanisms has been documented extensively, but there are experiments described in the literature and experience which support them.\textsuperscript{2,5,16,18,19,39,40} Our recent measurements of dynamic deposition of NaCl showed orders of magnitude difference in the equilibrium and dynamic solubility; importance of surface superheat, stagnation temperature, and surface roughness; and a variation of the NaCl atomic ratio on the surfaces from about 0.5 to 11.0 (Figure 12).\textsuperscript{40}

Dissolved impurities deposit from superheated steam when their concentration exceeds solubility, 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.

As Figure 5 shows, the region of passivity for iron is narrow, within pH 6 and 10. Since pH control in a power plant is mostly for the protection of the preboiler cycle, it often does not match the needs of the turbine surfaces. That pH depends on temperature, mechanical and vapor carryover of impurities and water treatment chemicals from the boiler, and their volatility (distribution between the vapor and the surface film). An example of this complex situation is shown in Figure 13, where calculated in situ pH for a PWR turbine is plotted.\textsuperscript{42} As can be seen, ammonia, which is used in all once-through fossil boilers and most PWR units, has little effect, particularly when an acid is present. Cyclamoxylamine and morpholine are stronger bases.

When hydrochloric acid forms in cycles with ammonia all volatile treatment (decomposition of chlorinated organics, Cl\textsuperscript{−} leakage from polishers, seawater leakage), 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\textsubscript{3} gas and HCl. This has been confirmed recently by a measurement of absorption spectra of NH\textsubscript{4}Cl in steam.

Deposits on turbine surfaces in units with sodium phosphate boiler water treatment (most drum boilers) are less corrosive. Sodium phosphate is a better neutralizing agent through the cycle; less acids are transported into the turbine and phosphate frequently co-deposits with harmful impurities, providing in situ neutralization and passivation. This is most likely the reason for lower frequency of turbine corrosion in systems with the phosphate water treatments.\textsuperscript{8}

Measure-
ments 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 (machining fluids and temperature, lubricants), storage (airborne impurities, preservatives), erection (airborne impurities, preservatives, cleaning fluids), chemical cleaning (storage of acid in hotwells), nondestructive testing (cleaning and NDT fluids), and layup (deposits plus wet air). Many of these compounds may contain high concentrations of sulfur and chlorine which would form acids upon decomposition. Decomposition of typical organics, such as carbon tetrachloride, occurs at about 150°C. Composition of all of the above compounds should be controlled (maximum of 50 to 100 ppm S and Cl has been recommended), and most of them should be removed before operation.

Molybdenum disulfide, MoS₂, is being implicated more and more as a corrosive in power system applications. It can cause SCC of superalloys and steels by producing a local acid environment. Its oxidation products form low pH solutions of molybdate and even ammonium molybdate, which can form during operation, causes rapid attack of turbine steels. MoS₂ has been used as a thread lubricant and in the process of disc-rotor assembling when the discs are preheated and shrunk on the rotor. During this process, MoS₂ can oxidize to MoO₂, later yielding molybdate on contact with H₂O. Analysis of disc bore and keyway surfaces often reveals the presence of molybdenum and sulfur. In steam, MoS₂ reduced the notch strength of disc steel, like H₂S, to about 30%. It has also been implicated in bolt and rotor shaft failures.

Layup corrosion increases rapidly when the relative humidity of air reaches about 60%. When deposits are present, the layup corrosion can be in the form of pitting or SCC. Pit growth of turbine blade and rotor alloys in chloride-metal oxide mixtures in wet air is about as fast as in a boiling deaerated 28% NaCl solution. In many foreign countries, procedures for layup protection by clean, dry air are used. We could speculate that some of the strange distributions of disc and blade cracking and pitting (one keyway out of three, one segment of disc rim or blade row) is caused by the rotor position during a long, unprotected layup or storage when condensing moisture could concentrate on the lower surfaces.

Progress in controlling turbine corrosion through better control of environment includes:
1. Decreasing concentration of corrosive impurities for better makeup and feedwater, lower air inleakage and condenser leakage, etc.
2. Operation of PWR units with AVIT ammonia treatment with feedwater pH above 9.6 to reduce erosion-corrosion of carbon steel piping and provide for better neutralization of acids and less iron transport.
3. Combined water treatment for once-through fossil units for excellent feedwater chemistry and clean boilers
4. Use of filming amines to separate surfaces from corrosions and reduce erosion-corrosion
5. Layup protection
6. Turbine washing after chemical upsets
7. Reduction or elimination of copper and its oxides and their synergistic corrosion effects by reducing oxygen concentration and pH or replacing copper alloys

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 simulated. 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 during the last 25 years, the experience was short and limited, and some problems developed which need to be corrected and considered in new designs and redesigns.

Design disciplines which affect turbine corrosion can be separated into four parts: (1) mechanical design (stresses, stress concentrations, Kj), (2) heat transfer (surface temperatures, heated crevices), (3) flow (moisture velocity, location of the salt zone, stagnation temperature, interaction of shock wave with Wilson line), and (4) physical shape (crevices, obstacles to flow, surface finish). These four effects (which interact) can produce undesirable stresses and impurity concentrations. In addition, some combinations of materials in contact, which are also chosen by the designer, can produce galvanic corrosion.

In the design of large turbines (reaching 1300 MW), limits of size and stress for conventional materials have already been reached. In particular, rotors and rotating blades are self-limiting; a size is reached when adding more material does not reduce any more stress because the centrifugal force also increases.

Recent design and material improvements and considerations include welded rotors, integral rotors, and disks without keyways; free-standing and integrally shrouded LP blades without tenon crevices and with lower stresses; titanium LP blades; new materials for blade pins and bolting; and flow guides and double-foil expansion bellows. In addition, these improvements, new designs, redesigns, and failed components should be more carefully checked to determine whether they meet corrosion design allowable and other corrosion-related requirements. Various aspects of design against environment sensitive fracture have been discussed before. Only a small part of this literature deals with the complexity of the problem. Probabilistic approaches are discussed in References 59 and 60. Problems with the probabilistic approach include a lack of sufficient statistical data on corrosion properties of materials, service stresses, and environments.

Not only should a turbine designer be concerned with corrosion, the system designer and architect-engineer must consider it as well. Since there will always be an impurity ingress, there must be systems to remove impurities so that they will not keep accumulating in the cycle. This is for gases, solids, and dissolved impurities. Copper is a nuisance in most modern power systems and makes chemistry and corrosion control
difficult in AVT systems such as in all the once-through and most PWR cycles. It is also bad in BWRs, and it is best not to use it. Water treatment, system design, and materials must be compatible. Even though these general statements sound trivial, deviations from them are probably the single most frequent and costly cause of US power system corrosion.

Discussion

Steam turbines can operate with high reliability and low corrosion failure rates. It has been proven in Europe and on units from US manufacturers which operate without problems in Japan. It can be achieved with current materials, good control of steam chemistry, and a design and manufacture that consider corrosion.

Combining worldwide experience (good and bad) with the improved knowledge of corrosion and strength of materials and of the action of the environment, the turbine designer should be able to optimize the component design or to calculate its life and inspection requirements. System designers and operators should give more weight to good steam chemistry.

Options, improvements, and corrective actions have been outlined in the preceding sections. The goal is to achieve good reliability during the life of the product. Some “debugging” of a new type of turbine and wear towards the end of the design life are expected. The most costly problem is a high level of unexpected random failures causing forced outages. Corrosion failures often fall into this group.

Summary and recommendations

General
1. Corrosion in turbines is generally more complex than usually recognized. Environmental considerations should include impurity concentration by deposition from superheated steam, evaporation of moisture, concentration in heated crevices and in oxides, and parameters which affect erosion-corrosion such as pH, velocity, and turbulence of moisture. Layout considerations and effects of solvents, lubricants, and cutting and NDT fluids should also be recognized.

Stress considerations should include effects of load history, interactions with cycling, and residual and multiaxial stresses. Particular attention should be paid to crack initiation because that is the corrosion phase most influenced by the local environment and stress.
2. Because of their large size and steam load and resulting forces and stress, it is difficult to build large modern turbines with a high degree of margin (low stress). It is, therefore, necessary to combine a refined design with the best corrosion protection (water chemistry and layout) possible. By eliminating a few weak links in the design and water chemistry, a reliable operation can be achieved.

Material
1. Materials—Design. For the same types of steel, the higher yield strength materials are more susceptible to stress corrosion and have lower fracture toughness. The traditional design allowables or safety factors based on the ratio of average or local stresses to strength can become nonconservative when higher strength steels are used and should be supplemented by a set of corrosion design rules.
2. Material properties. Besides the above effects of material strength, heat treat effects, temper embrittlement of low alloy steels, and sensitization of stainless steels should be considered.
3. Material—Surface finish. Most machining processes produce compressive residual stresses which are beneficial for localized corrosion and corrosion fatigue, unless pits penetrate the compressive stress layer. Drilling and abrasive grinding can produce tensile residual stresses. Absorbed machining can also produce microcracks and laps, which can be detrimental. Control of machining is, therefore, essential for corrosion prevention.

Environment
1. Average concentrations of major impurities in turbine steam should not exceed a few ppb limits and about 0.2 μS/cm conductivity. Standards and recommendations given by different organizations and turbine vendors are generally adequate.
2. In units with corrosion problems, additional impurities beyond those specified should be measured and their sources contained. These include organic acids, carbonates, fluorides, polisher resin fines, and copper.
3. Transient steam chemistry upsets associated with system transients are the most frequent cause of accumulation of corrosive impurities and corrosion. Chemical monitoring should be capable of an identification of these transients.
4. The most effective measures to achieve the best possible water and steam chemistry are: good condensers, low air leakage and good deaeration, good operation of condensate polishers, good makeup, and elimination of copper in AVT systems followed by optimization of the pH-oxygen regime.
5. Corrosion during an unprotected layup can be as rapid as during the operation with impure steam. It is, therefore, necessary to clean a turbine and to protect it by clean dry air.
6. Boiler chemical cleaning practice with the hot cleaning solution stored in the hotwell should be avoided. Vapors of the solution can condense on turbine and heater surfaces and cause corrosion.
7. Normal AVT treatment with ammonia gives little corrosion protection to the turbine. At higher temperatures, there is little dissociation and, because of its volatility, little ammonia is found on metal surfaces in the salt and wet zones. In these units, impurity concentration in steam must be low to avoid their local concentrations. Some benefits can also be derived by using stronger bases such as cyclohexylamine and morpholine, or increasing ammonia concentration to about 10 ppm (where possible). Injection of hydrazine into the turbine steam is also beneficial.

Design
1. Design—Stresses. The mechanical design concepts for avoidance of turbine corrosion should include evaluation of safety factors against τ<sub>G</sub>, K<sub>SCC</sub>, K<sub>SSC</sub>, D<sub>τ</sub>≡D<sub>cr</sub>, and life limit, pitting rate, and pit depth limit.
2. High multiaxial tensile stresses, strain (mechanical or thermal) fluctuations, and other mechanical interactions and large component sizes, a more conservative approach should be taken. True residual stresses (micro and macro) should be considered.
3. Material—Crevises. Crevises should generally be avoided. They act as impurity traps and concentrators, can form differential oxygen concentration cells, and could generate high stresses by the oxide growth mechanism. The worst crevices are those with trapped corrosive impurities and metal temperature within the “salt zone.” Some disc bore and keyway and blade tenon-shroud crevices fall in this category.
4. Design—Flow of moisture. To avoid erosion-corrosion, 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 should receive special attention.
5. Material—Galvanic effects. When dissimilar materials are coupled together, crevice effects could be enhanced by the shift of corrosion potential. In some environments, this shift could be in the region where one of the coupled materials is susceptible to SCC or pitting.

Materials Performance
6. Design—Inspectability. In designing turbine components, the question of inspectability should be addressed. In particular, crevice and high stress regions should be reached by available inspection techniques.

7. Machining, cleaning, NDT, and other compounds. 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 decomposition of residues of these compounds, hydrochloric, sulfuric, carbonic, and organic acids can form. It is recommended to control their composition and use. For the compounds which can remain on turbine surfaces during operation, low ppm levels of chlorine and sulfur are recommended.

Further research

1. A computerized corrosion data bank should be developed so that the thousands of data points which exist can be summarized and utilized in design and corrosion testing.

2. Corrosion testing of turbine materials should be directed more to obtaining corrosion characteristics usable in design such as $R_{SCC}$, $K_{SCC}$, initiation time, $d_{AT}$, corrosion fatigue limit, $A_{RH}$, and pitting rate.

It should be done in realistic environments representing good steam chemistry, and few off-site environments.

Effects of the load history and spectra (which can influence stress distribution and localized corrosion) and factors of strain cycling and multiaxiality of stress should be explored.

3. Impurity concentration processes under realistic turbine conditions should be investigated, particularly dynamic solubility and rate of deposition and corrosiveness of deposits.

4. Effects of various current manufacturing, testing, storage, preservation, erection, initiation operation, cleaning, and NDT practices on metallic passivation and the onset of corrosion should be investigated.

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