The International Edition

PPCHEM PowerPlant Chemistry®

The Journal of All Power Plant Chemistry Areas

December 2005

Plant managers, please read page #721.

ISSN 1438-5325

Visit us at http://www.ppchem.net

Volume 7 (2005) No. 12

Condenser Tube Fouling and Failures: Cause and Mitigation

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ABSTRACT

The two most common condenser tube problems faced by chemists are internal tube fouling and tube failure. Fouling can have a major impact on power station generating efficiency and/or capacity, and tube leaks can seriously impact unit availability and reliability. Fundamental understanding of the root cause(s) of these issues and their mitigation is essential to resolving these problems and/or preventing their occurrence.

INTRODUCTION

Maintaining clean, leak-free condenser tubes is critical to low-cost power plant operation. Cleanliness is usually an internal (waterside) tube concern, and problems most commonly occur due to scale precipitation, particulate deposition, or microbiological growth. Fouled tubes may result in two critical problems: (1) unit performance loss due to impedance of heat transfer, and (2) tube failure. Tube failures can originate due to damaging conditions on either the waterside or steamside of tubes, resulting from a variety of mechanisms. The effects of condenser tube leaks can be devastating to plant availability and reliability; expensive equipment replacement may be required in severe situations. The root causes of condenser tube fouling and failures are relatively well understood, and are generally preventable and correctable.

FOULING

Fouled condenser tubes cause significant economic problems for power station operation. Reduced heat transfer capability results in a higher backpressure in the condenser and less efficient turbine performance, requiring increased fuel or even limiting generation capacity. A second serious concern is that condenser tube leaks commonly occur as a consequence of fouling [1].

Types of Fouling

Condenser tube fouling, which is mostly a tube interior concern, generally falls into the categories of (1) microbiological, (2) scale, (3) deposition, (4) corrosion products, and (5) tubesheet pluggage.

Microbiological fouling routinely occurs in natural waters, as many bacterial species will naturally colonize and grow on inert substrates; the temperature at the interior wall of condenser tubes is ideal for growth of some bacteria. The resulting mass is frequently low in organic solids (10–30 % after drying), with the majority of constituents being inorganic particulates from the cooling water that have become incorporated into the microbiological slime. Even a thin layer of microbiological fouling can be particularly detrimental to heat transfer, as much of the slime mass consists of water, which conducts heat poorly.

Scale (mineral crystallization) occurs on heat transfer surfaces under a combination of dissolved mineral concentration and temperature effects. Scaling of certain common constituents in natural waters (calcium carbonate, calcium phosphate) is promoted by elevated temperatures, such as exist on the interior wall of condenser tubes, particularly towards the outlet end. Other scale-forming minerals (calcium sulfate) are more likely to form at cooler temperatures. Scale can drastically reduce heat transfer, depending on the specific mineral formed and its thickness. While scaling water chemistry is not normally associated with corrosion, it is very possible that crevice corrosion will occur beneath scale.

Particle deposition generally occurs in condenser tubes when the flow rate is inadequate to keep particulates in suspension. Design flow through condenser tubes is often 2–3 $m \cdot s^{-1}$ (7 to 10 ft/s), but this is an average (bulk flow), and some tubes may experience much lower flow than others. This can be a problem if the waterbox is not full, and upper tubes receive intermittent flow. Commonly, areas of low flow result from partial blockage on the tubesheet, or by an object lodged within a tube. It is not likely that particle deposition will cause a significant loss of heat transfer for the condenser, but it may serve as an initiation site for crevice corrosion. Common types of fouling particulates in condensers include sediment/silt, diatoms, coal dust, and minerals precipitated from the cooling water (calcium sulfate, calcium phosphate, silicates, etc.).

Corrosion products can grow relatively thick on the surfaces of certain tubes, primarily copper alloys. Scale or deposition promotes copper oxide growth, and in some cases a thin surface scale will enhance the growth of a thick underlying copper oxide layer, which will inhibit heat transfer and establish sites for crevice corrosion. Corrosion product growth is enhanced by more corrosive waters.

The condenser inlet tubesheet is subject to blockage by various materials and debris, including rocks, concrete pipe debris, cooling tower materials (plastic fill/wood), chunks of ash or coal, pieces of rust, paper trash, leaves and other vegetation, and aquatic animals (crayfish, fish, clams). The primary effect is reduced flow to certain tubes, which results in particulate deposition and increased opportunity for microbiological growth. If major tubesheet blockage occurs, the condenser vacuum can be significantly degraded.

Foulant Removal

There are a number of approaches to removing foulants from condenser tubes. To select the optimum removal method, the foulant must first be identified, if possible. If the unit can be brought off-line for inspection, material in the condenser tube can be collected and analyzed. Microbiological fouling may be difficult to identify when wet, but typically forms flakes that readily detach from the tube wall when dry. Macrofouling of the tubesheet can be recognized by the presence of debris in the waterbox, which tends to fall off the tubesheet when flow is discontinued.

On-Line Foulant Removal Efforts to remove certain foulants on-line can be successful when the probable foulant is known from experience. The pH can be lowered to remove specific foulants such as calcium carbonate (pH < 5.8) and calcium phosphate (pH < 4.0), although there is a risk to the system by exposure to low pH. If mechanical cleaning systems are in place (abrasive sponge balls or similar recirculating cleaning tools), they can be used; such systems are likely to be effective with very soft foulants (microbiological or deposits), but may not be helpful for scale or corrosion product removal. Dosing with high levels of biocides for short periods may help to remove biofilms, although established microbiological growths are resistant to biocides. If flow can be increased, settled particulates might be removed, provided caution is exercised in units having copper-alloy tubes.

Off-Line Foulant Removal Removal of foulants with the unit off-line is frequently the most effective approach. The tubes and system can be examined directly, so identification of the problem is more certain, and therefore selection of the best means of removal is more likely.

An off-line chemical cleaning to remove scale or corrosion products in condenser tubes is likely to be successful, provided the process is correctly designed and implemented. However, a number of drawbacks to chemical cleaning must be considered, including:

- safety
- cost
- waste disposal
- time required
- insuring complete foulant removal
- maintaining integrity of base metal

Incomplete foulant removal can occur when the foulant is dislodged from the tube during a chemical clean, but not completely dissolved or adequately rinsed, leaving a residue of sludge. Alternatively, part of the foulant may be dislodged from the tube, and part remain adherent (particularly with scale that is a composite of multiple minerals). The tubes should not be left in a "half-cleaned" condition, as increased corrosion may occur where base metal is exposed. In either case, following a chemical clean with mechanical removal, if feasible, is a good practice to insure tube cleanliness.

Several techniques are commonly utilized to mechanically remove foulants. Mechanical scrapers (metal or plastic) are widely applied, and specific scrapers have been designed to remove virtually all common foulants, even hard mineral scale such as calcium carbonate (*Figures 1 and 2*). Scrapers are propelled at 3–6 $m \cdot s^{-1}$ (10 to 20 ft/s) by pressurized water at about 2 MPa (300 psig), so loosened debris is rinsed from the tube with the scraping process. Concern has frequently been expressed regarding the affect of metal scrapers on base metal. Careful evaluation over many years has led to the conclusion that there is virtually no risk of base metal damage with metal scrapers that are properly designed and used [2]. One advantage of metal scrapers is that they are effective against a variety of foulants, so may be useful for general purpose cleaning if the foulant is not identified. However, some foulants are better removed by identification and matching with a specific scraper design [3].

Figure 1: Metal tube scrapers, Hex Cleaners, for general purpose tube cleaning (Conco Systems, Inc.).

Figure 2: Cal Buster, designed for breaking up hard calcium carbonate scale (Conco Systems, Inc.).

Other common mechanical foulant removal techniques include metal-wire brushes (Figure 3) and high-pressure water. Wire brushes are propelled individually down tubes, similarly to scrapers. Brushes may be particularly useful for tubes that have inlet-end metal inserts, or inlet epoxy coatings, which can reduce the internal diameter. High-pressure water ("hydroblasting") can be effective on some foulants, particularly soft materials such as microbiological films and particulate deposits, but may incompletely remove very adherent scales. Additionally, hydroblasting must be performed carefully, as the water will quickly cut through relatively soft condenser tubing (such as copper alloys) if the spray nozzle is allowed to pause for too long. Where inlet-end metal inserts are present, hydroblasting can severely deform the inserts by forcing water into the insert-tube interface.

Figure 3:

Stainless Steel Tube Cleaning Brush, for general purpose tube cleaning, including when scrapers will not fit properly due to inlet-end inserts or epoxy coating (Conco Systems, Inc.).

Microbiological fouling can be removed by almost any mechanical cleaning technique, but can also be addressed by allowing the condenser tubes to dry out (Figure 4), and then flushing with water (returning to normal cooling water flow). This rather passive cleaning approach requires that the underlying foulant present is microbiological in nature, even if the bulk of the foulant consists of inorganic particles.

Macrofouling is essentially a mechanical blockage issue with microfouling consequences. This problem is corrected by physical removal of trash, etc. from the waterbox, and rodding out of chunks of debris lodged in tubes.

Figure 4: View of inlet-end tubesheet through manway; tubes are filled with microbiological slime that is dried and flaky.

Fouling Prevention

Steps can be taken to significantly reduce the possibility of condenser tube fouling. Incoming water may be treated for particulate removal by the use of settling ponds, or by filtration. Clarification can remove both particulates and some dissolved foulants, such as hardness (calcium and magnesium). Prevention of macrofouling is primarily accomplished by screens intended to block large debris from reaching the condenser. These screens are sized to block any potential foulant that is too large to easily pass through the condenser tubes. For recirculating fresh water cooling towers, the probability of scale formation is directly related to evaporative cycles, so scaling control is partially managed by limiting cycles of concentration.

Certain chemicals added to the cooling water are effective at preventing specific types of tube fouling. Biocides (oxidizing or non-oxidizing) are used to minimize microbiological growth, although environmental discharge restrictions limit their use in once-through cooling systems. Antiscalant specialty chemicals reduce the probability of scale formation; pH reduction also helps in this regard (typically with sulfuric acid addition). Dispersants can lessen the possibility that particulates will settle or adhere to tube interiors. Corrosion inhibitors are often added (e.g., zinc and phosphate for carbon steel, triazoles for copper alloys).

Mechanical approaches to fouling prevention in tubes include recirculating scraping/wiping devices, such as sponge balls. These items must pass through condenser tubing without much force (carried with circulating water flow), yet apply slight pressure to tube interior walls without becoming lodged within the tubes. Some maintenance is required, as there is gradual wear on the cleaning pieces, and they must be periodically replaced. These devices can be very effective in limiting microbiological film growth, but their effectiveness against scaling is uncertain.

Adequate flow rate is another important mechanical component to fouling prevention. Low flow provides increased opportunity for microbiological colonization and growth on tube interior walls, and for settling of particulates. On the other hand, excessive flow (greater than $2.1\ m \cdot s^{-1}$ (7 ft/s)) can cause damage to copper-alloy tubing, so an optimal range may be required. Since the average flow will be different than 'worst-case' flows in specific tubes, achieving a desired overall flow rate may not completely resolve these fouling issues.

CONDENSER TUBE FAILURES

When a condenser tube leaks, cooling water is drawn by the condenser vacuum into the high-purity condensate [4]. The impact of this contamination will depend primarily on (1) the quantity of cooling water inleakage, and (2) the quality of the cooling water. State-of-the-art detection of cooling water ingress requires continuous sodium and cation conductivity monitoring of condensate and/or feedwater.

The quantity of inleakage is relatively straightforward, depending on the size of the breach in the tube wall. Depending on the tube damage mechanism, the leak may increase in size with time, or remain unchanged. It is common for certain leaks to operate intermittently; this may be due to thermal expansion/contraction, as with load swings or unit cycling, or can occur if particulates in the cooling water flow into the leak and plug it temporarily.

The significance of inleakage is directly dependent on the cooling water quality. High-quality freshwater (commonly 150–400 $mg \cdot L^{-1}$) cooling a once-through condenser will permit relatively few contaminants to enter the condensate, even with a significant volume of inleakage. The same water cycled in cooling towers may be ten to fifteen times more concentrated in dissolved solids than its source (3 000–4 000 $mg \cdot L^{-1}$). Poorer quality freshwater, perhaps from shallow wells, can be considerably higher in dissolved solids (1 500–2 500 $mg \cdot L^{-1}$), and may be cycled in cooling towers up to 25 000 $mg \cdot L^{-1}$. Seawater is about 3.5 % dissolved solids (35 000 $mg \cdot L^{-1}$), and is nearly always used for once-through cooling.

When cooling water leaks into the steam cycle, the impact is highly dependent on the specific constituents present. Inleakage to the steam cycle by seawater is particularly detrimental due to its high concentration of chloride (19 000 $mg \cdot L^{-1}$), which can cause severe damage to boilers and turbines. For this reason, tubes for seawater use are made from highly corrosion-resistant alloys (titanium or high-alloy stainless steels), and demineralizers are commonly employed to remove contaminants from condensate, in the event of a leak.

Cooling water ingress usually results in pH shifts in the boiler, which can be dramatic. Whether the pH decreases or increases depends largely on whether the magnesium or bicarbonate ion in the cooling water is dominant, according to the following reactions that occur in the boiler:

$$Mg^{2+} + 2H_2O \rightarrow Mg(OH)_2 + 2H^+ \quad \text{(pH decrease)} \qquad (1)$$

$$HCO_3^- \rightarrow CO_2 + OH^- \quad \text{(pH increase)} \qquad (2)$$

Eq. (1) commonly is predominant in seawater and with freshwater that has been concentrated by cooling towers; Eq. (2) may be dominant with once-through freshwater sources.

System design and boiler water treatment are selected with consideration of minimizing damage from condenser tube leaks. Condensate polishing demineralizers are ideal for catching cooling water ingress before it travels to the boiler and turbine. For units without these polishers, phosphate-based boiler water treatment, including the ability to feed phosphate quickly when a condenser leak occurs, serves to buffer pH shifts, and will prevent hardness ions (calcium, magnesium) from forming scale in the boiler.

Categories of Condenser Tube Failures

Condenser tube leaks may occur from the steamside or waterside of the tubes, and can be caused by chemical or mechanical factors, or a combination of the two. The listing of failures here is not comprehensive, but covers the majority of common damage mechanisms.

Steamside Failures: Mechanical Causes Impact damage is a common mechanical failure mechanism for all condenser tube alloys. Objects left in the system after a low-pressure turbine overhaul can be propelled into the condenser at high velocity during unit startup, and leave severe dents or holes upon impact (Figure 5).

Erosion from high-velocity water or steam is another mechanical failure mode that affects all common alloys used for condenser tubes. Water droplet erosion from steam condensation exiting the low-pressure turbine frequently damages tubes at the top of the condenser bundle, but often is long-term accumulated damage, taking years to result in failure. More severe damage of this type results from various drain lines entering the condenser, bearing high-velocity, high-temperature steam or water (Figure 6). While these drain entries are baffled where the possibility of condenser tube damage exists, the baffles may eventually be eroded away, or break loose for various reasons.

Steamside Failures: Corrosion Corrosion-induced steamside failures in condenser tubes are primarily manifested as stress corrosion cracking (SCC) or condensate

Figure 5: Admiralty brass tube, failed by impact damage due to unknown object propelled into condenser at startup, after turbine outage.

Figure 6: Admiralty brass tube, failed by drain line erosion due to failed valve.

grooving, caused by volatile gases dissolving into the condensing steam. This mechanism primarily affects brass tubes, although copper-nickel tubing can be susceptible. Ammonia is most frequently the corrodent, in combination with oxygen. While ammonia may be controlled to non-threatening levels in bulk condensate ($< 0.5 \text{ mg} \cdot L^{-1}$), local concentrations in the condenser can be much higher. In particular, the air removal section accumulates volatile gases (ammonia, oxygen), which dissolve into the condensate present to some extent. Tube support plates serve as a collection point for condensate drainage, due to slight sloping of the tubes, so that the point of tube entry into the support plate receives continual exposure to corrosive condensate. The tubing may lose wall thickness by general corrosion (condensate grooving), or experience SCC, depending primarily on the stress levels in the tube metal (*Figures 7 and 8*). In the case where the air removal section is tubed with an alloy resistant to ammonia-based corrosion, brass tubes below this section may still be susceptible to the corrosive draining condensate.

Condensers with brass tubing have also experienced severe pitting and failures by SCC due to sulfurous acid, in systems where sodium sulfite is used for feedwater oxygen scavenging (*Figure 9*) [5,6]. Sulfite breaks down in the boiler to generate sulfur dioxide gas:

$$2\,SO_3^{2-} \rightarrow SO_2 + SO_4^{2-} \quad (3)$$

Sulfur dioxide subsequently dissolves into condensing steam to generate sulfurous acid:

$$SO_2 + H_2O \rightarrow H_2SO_3 \quad (4)$$

Since sulfur dioxide is relatively hygroscopic, sulfurous acid may condense anywhere along the tube length, although the air removal section will still probably experience the worst damage. General corrosion of the tube surface results in a thick layer of cupric oxide (CuO), providing sites for under-scale concentration of corrodent. Although sulfurous acid condenses in the steam, it is oxidized to sulfuric acid relatively quickly, so the exact mechanism of corrosion is not clearly defined. However, SCC is clearly the mechanism of failure that results. Sodium sulfite is best applied only to boilers at pressures less than 5.9 MPa (850 psi). Units that once used sodium sulfite and then switched to ammonia-based control (including hydrazine) may experience confusion regarding whether ammonia or sulfurous acid was the primary cause of failure. Sulfite-based SCC develops very slowly, and deep cracks may persist for many years without causing failure. Additionally, the thick cupric oxide scale may serve to block leakage, even when the tube wall has been completely penetrated by a crack.

Figure 7: Ammonia condensate grooving in admiralty brass tube. Grooves formed on each side of tube support plate.

Waterside Failures: Mechanical Causes The major mechanical influence on waterside condenser tube failures is the erosion component of erosion-corrosion damage. This failure mechanism is almost exclusively a problem for copper-alloy tubing, with brass being more susceptible than copper-nickel. The mechanism initiates with normal oxidation of base metal. The oxide is relatively protective at low flow rates, but it is mechanically weak and can be removed by high flow, particularly in combination with abrasive particulates. With the oxide removed, freshly exposed base metal quickly re-oxidizes in the oxygen-saturated cooling water environment, and the oxide is subsequently removed mechanically [7].

Figure 8: Stress corrosion cracking in admiralty brass tube due to excessive ammonia concentrations in the air removal section. Magnification 5x.

Figure 9: Stress corrosion cracking in admiralty brass tube due to carryover of sulfur dioxide, in sulfite-treated boiler. Magnification 4x.

Erosion-corrosion occurs where local flow is high, regardless of bulk flow. This scenario can develop in a variety of situations, including:

- as a result of plugging of many tubes, forcing the same *total flow* through a smaller number of tubes, therefore at higher velocity;
- at tube inlets, where water entering the tubes is turbulent due to a sudden change in the direction of flow (Figure 10);
- adjacent to partial flow blockage in tubes, where the reduced diameter leads to a concomitant increase in flow rate (Figure 11);
- in front of intermittent scale of sufficient size that flow impacting the scale is re-directed downward into the tube, at high turbulence (Figure 12); and
- randomly along the tube length, particularly in once-through condensers, where sediment is sometimes relatively high (as in river water during high flow periods).

In any of these scenarios, abrasive particulates (fly ash, sediment) will increase the rate of oxide removal, and therefore the rate of metal loss.

Figure 10: Inlet-end erosion-corrosion in admiralty brass tube. Magnification 3x.

Figure 11: Erosion-corrosion failure in 90-10 copper-nickel tube, due to accelerated local flow around an object lodged in the tube. Magnification 4x.

Figure 12: Erosion-corrosion around residual calcium carbonate scale in admiralty brass tube, due to local flow eddies and acceleration. Magnification 3x.

Waterside Failures: Corrosion Under-deposit or under-scale (or crevice) corrosion is a frequent damage mechanism for copper-alloy and austenitic (300-series) stainless steel condenser tubes. The specifics of crevice development and subsequent corrosion can vary greatly, but the mechanism is essentially the same – the development of differential concentrations between the bulk environment and that beneath the deposit, in which the under-deposit environment is corrosive to base metal. One means of developing this scenario results from the depletion of oxygen beneath the deposit, through reaction with either base metal or the deposit itself. The oxygen-depleted region becomes anodic, and base metal is oxidized according to:

$$Cu \rightarrow Cu^{2+} + 2e^- \quad (5)$$

whereas the metal adjacent to the crevice receives the released electrons for the cathodic reduction of oxygen:

$$O_2 + 2H_2O + 4e^- \rightarrow 4OH^- \quad (6)$$

Additional potential differences develop due to the concentration of constituents such as anions (chloride, sulfate) beneath the deposit. These are drawn towards the under-deposit region by the positive electrical charge of metal ions that are thermodynamically motivated to exit base metal. In most cases, both differential oxygen and differential anion concentrations probably work together to promote under-deposit corrosion. This sequence of events is depicted in Figures 13–16.

Some common modes of deposition, and means of addressing fouling issues, were discussed earlier.

Microbiologically influenced corrosion (MIC) is a particular problem with austenitic stainless steels, although it has been reported to affect copper alloys as well. The highly

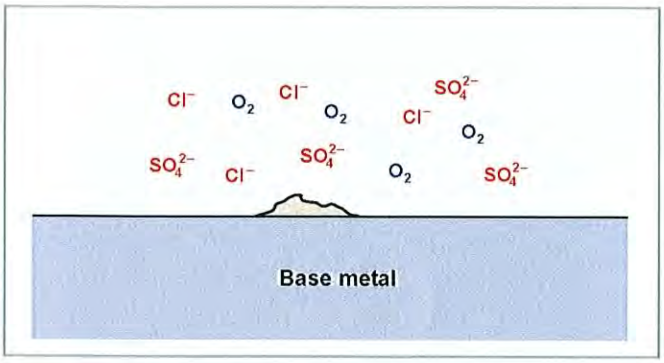

Figure 13: *Crevice (under-deposit) corrosion: cross-section depicting local deposit on tube surface.*

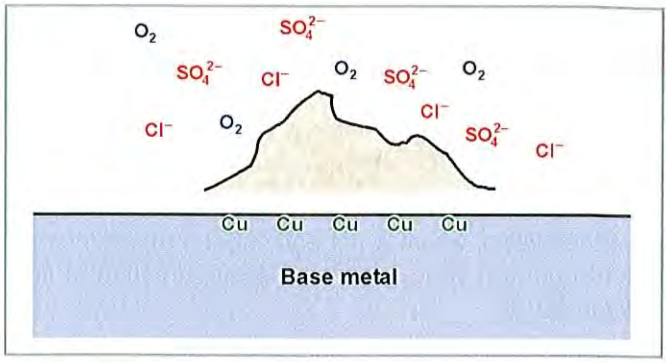

Figure 14: *Crevice (under-deposit) corrosion: enlargement of Figure 13, showing crevice between deposit and tube metal.*

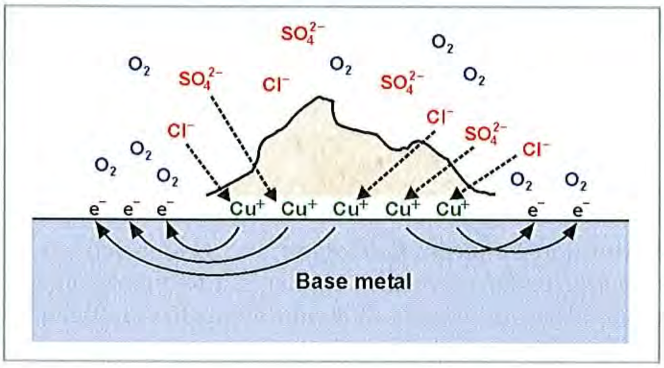

Figure 15: *Crevice (under-deposit) corrosion: electrochemical interactions under deposit in cooling water: (1) electrons released from copper are reduced by oxygen, (2) anions are attracted to positively charged metal ions in the crevice.*

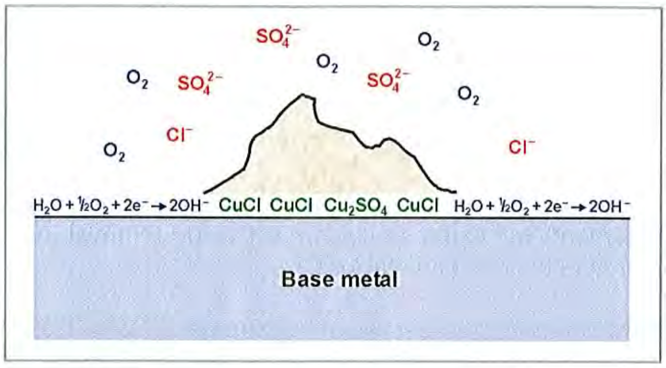

Figure 16: *Crevice (under-deposit) corrosion: cuprous chloride and cuprous sulfate salts accumulate in crevice, as base metal is lost.*

passive surface oxide layer on stainless steels, when disrupted, subjects base metal to an intense focus of anodic current. Microorganisms can provide such a disruption. Besides serving as a deposit under which crevice corrosion can occur, microorganisms may generate corrodents (converting sulfate to hydrogen sulfide) or deposition (manganese dioxide, iron oxides) that accelerate corrosion (Figure 17).

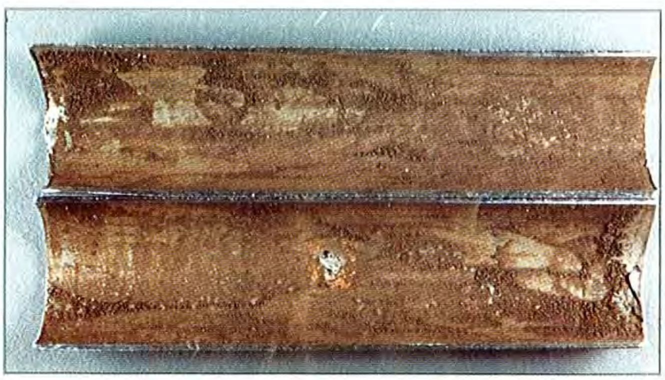

Figure 17: *Manganese oxide deposits in 304 stainless steel tube; failure at arrow.*

Tube Failure Mechanisms Not Caused by Service
Condenser tubes may fail in service due to specific situations other than the service environment. Off-line chemical cleaning, if not accomplished properly, can cause tube damage that later results in failures (Figure 18). Manufactured defects, such as incomplete or improperly formed weld seams, or denting during handling, can lead to failures (Figures 19 and 20). During tube installation, rolling tubes into the tubesheet requires precise quality control to avoid excessive stresses or crevices (Figure 21).

Condenser Tube Failure Correction

When a condenser tube leak is detected, a decision on a course of action must be made. Factors considered include:

- amount and type of contamination entering the condensate
- historical problems with cooling water contamination and condenser leaks
- urgency of generation, and time remaining until evening or weekend

- capacity of condensate polishers (if present)
- whether the unit can be brought to half-load, or must be taken off-line

Identification of which waterbox is leaking, for typical units with split waterboxes, can accelerate repair of the failure. This can be done at full load by tracer gas injection upstream of the waterbox (sulfur hexafluoride, SF_6, or possibly helium for large leaks), or by isolating one waterbox and draining cooling water until evidence of sodium/cation conductivity disappears (this will provide approximate leak level, as well as confirming which half of the condenser contains the leak). In cases where multiple leaks are present, and at different rates of inleakage, this process may be impossible to conduct adequately.

Several approaches to identifying the specific tube/tubes that are leaking have been used. For on-line identification with an isolated, drained waterbox (at half-load), both ends of a leaking tube will be pulling in air from the tubesheets. Tracer gas injection (helium or sulfur hexafluoride) is a very effective and sensitive means of locating the leaking tube(s); SF6 is very sensitive, and particularly useful for small leaks. Less sophisticated indicators such as shaving cream or thin plastic wrap (must be applied to both inlet and outlet ends of the tube), or a flame/smoke, are often effective in identifying the leaking tube(s). For off-line identification, the hotwell is flooded with condensate, and tubesheets are examined for those with water running out. A fluorescent dye can help greatly in distinguishing leaking tubes from those that may still have water draining slowly. Although the theory behind the identification of leaking tubes is relatively simple and straightforward, there are numerous pitfalls that occur in practice, and experience in locating leaking tubes is invaluable.

When a leaking tube is located, both ends of the tube must be plugged with water-tight seals. A variety of tube plugs are available for this function, but all must be applied properly for long-term reliability, and (sometimes) with a view towards future recovery of either the leaking tube, or its replacement.

Of critical importance to addressing condenser tube leaks is identification of the root cause, particularly for repeat leaks in the same condenser over a short time frame, which may be due to the same failure mechanism. Extracting a tube from the bundle for laboratory examination may add a few hours to an outage, and detract from the plant's immediate objective of minimizing downtime. However, failure to address repeat condenser tube leaks early on may ultimately result in very high costs for equipment repair (e.g., turbine blade cracking), along with multiple outages to plug continuing leaks. Condenser tube leak incidents that may fall into a pattern of repeat failure mechanisms must be addressed at the earliest opportunity; at

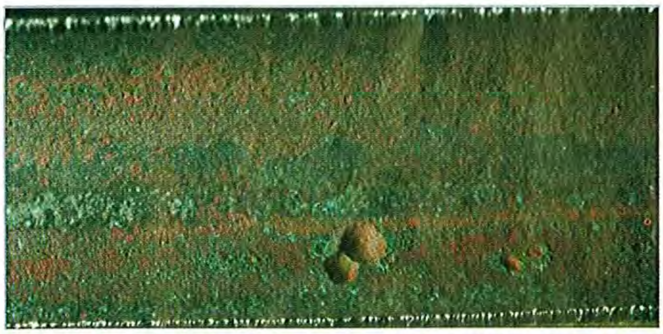

Figure 18: Severe pitting in 90-10 copper-nickel tube, following chemical cleaning that included excessive exposure to cleaning chemical. Magnification 2x.

Figure 19: 304 stainless steel tube with defects at incompletely formed weld seam. Magnification 4x.

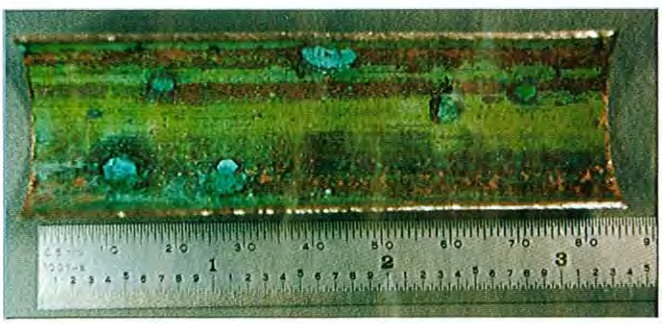

Figure 20: Admiralty brass tube with internal pitting, in correspondence with external dents.

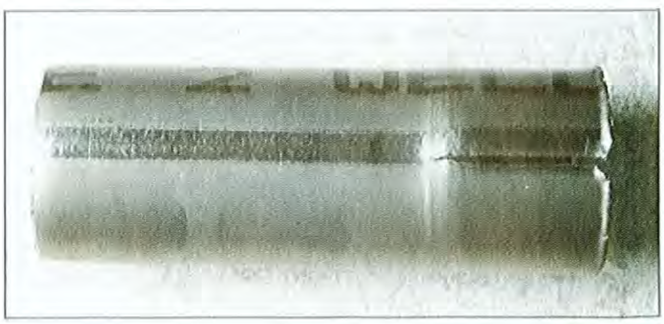

Figure 21: Titanium tube that failed at weld seam upon rolling into tubesheet, due to manufacturing embrittlement, combined with freezing while filled with water during temporary storage.

the very least, several failed tubes should be designated for removal in conjunction with a planned unit outage.

The cost for addressing the root cause of condenser tube failures can vary from minor (e.g., replacing corroded screens for removing macrofoulants) to major (e.g., replacing all condenser tubes with a problem-resistant alloy). It is important to understand and evaluate the actual and potential costs of condenser tube leaks to steam cycle components in order to choose a cost-effective course of action for correction.

Prevention/Avoidance of Condenser Tube Failures

Companies operating power stations with water-cooled condensers should strive to apply state-of-the-art, industry-proven technology to prevent or minimize condenser tube failures. Alloys that have proven reliably failure-resistant for a specific application should be installed in new units. Non-destructive evaluation by eddy current testing should be applied periodically to determine the status of flaws in the tubes (pre-existing or developing). Eddy current testing also permits plugging of those tubes that are determined to have considerable wall loss, thereby avoiding failure and contamination of the high-purity steam cycle water, as well as unit unavailability to repair the leaks. Chemistry control programs most appropriate to avoid fouling and corrosive situations should be applied. Those damage mechanisms that commonly afflict certain tube alloys (e.g., erosion-corrosion in admiralty brass) should be considered a constant threat, and preventive measures evaluated (such as installation of inlet-end metallic inserts that are more resistant to flow-induced damage).

CONCLUSIONS

The fouling and failure of condenser tubes is an expensive and frustrating problem for many electric-generating stations. However, the causes of these troubles are generally well understood, and their correction is often very straightforward, although not necessarily inexpensive. Diligence in following best industry practices will go a long ways towards preventing such problems. If a repeat condenser tube failure scenario exists, identifying the root cause and correcting it in a timely manner is of vital importance.

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Paper presented at the Eskom International Conference on Power Plant Chemistry, Mabalingwe, South Africa, November 8–11, 2005.

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Discussion Board

In September 2004, we installed – following your recommendations and requests – a discussion board on the homepage of our journal. Participation in the discussion in this Forum may help you carry out your professional activities more knowledgeably and responsibly. You may also establish contacts to colleagues around the world active in the power plant chemistry area.

What is the situation more than one year later? The Forum is visited relatively often. Some of the postings have been read more than 300 times:

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However, the number of active postings remains disappointing. We have many curious readers; unfortunately, they are perhaps too insecure or laid-back to take an active part in the discussion. What is your opinion?

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and help us to make our Forum into an active platform for all very exciting power plant chemistry areas.