Water - the "new oil?"

Important cooling water monitoring parameters no plant should ignore

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Cooling water chemistry - Friend or foe

Cooling water chemistry - friend or foe

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INTRODUCTION

For the power plant operator, the challenges with cooling water are greater than they have ever been. Sources of water are drying up. Twenty five years ago, it was common to site a new power plant where abundant cooling water was available, such as near a lake or river. Today, these site options are rarely available. Innovative solutions are being utilized wherever found, and recycled water from water treatment plants have become a dominate replacement source[1]. One plant in New York City is utilizing water pumped from the subway system drainage. Whatever the source, the water is also not in unlimited supply. In plants with once through cooling, permits usually restrict total volume and/or discharge temperature rise. This requires that most new plants build cooling towers so that the water can be used multiple times. Evaporation from those towers results in increased concentration and when the it exceeds certain limits, scaling can occur. Additionally, existing sources of cooling water are changing. Environmental requirements have become more stringent. Although this has generally resulted in "cleaner" water, the changes in some rivers have allowed the microbiological activity to thrive. In these cases, the "cleaner" water can be more corrosive water.

PARAMETERS TO MONITOR

To understand the aggressiveness of your cooling water, a number of chemical and operational factors need to be considered. One snapshot at a single time is not sufficient. Instead, multiple measurements should be carefully recorded over as long as a period as possible, preferably an entire year. Unusual events, such as large rainfalls, hot spells, and snow melts should also be recorded so that when a change in the chemistry occurs, the root cause is clear. A utility needs to understand potential "worse case" conditions to be prepared for these situations. Following are some of the conditions to watch.

Chloride content

Chloride content is one of the primary parameters used to evaluate for operations and material selection. When the level exceeds certain thresholds (as low as 100 ppm for TP 304),

chlorides will react with the passive protective film on the tube surface. The surface then activates and active corrosion is initiated. This commonly occurs in random isolated locations and as the corrosion gains depth, the onset of pitting begins. As the pit grows deeper, the solution in the pit becomes more concentrated, more conductive, and has a lower pH. The result is progressively higher corrosion rates. The potential for activation increases as either the temperature or the chloride level increase, or the pH decreases.

For copper alloys, alloying additions to improve chloride resistance inclu-

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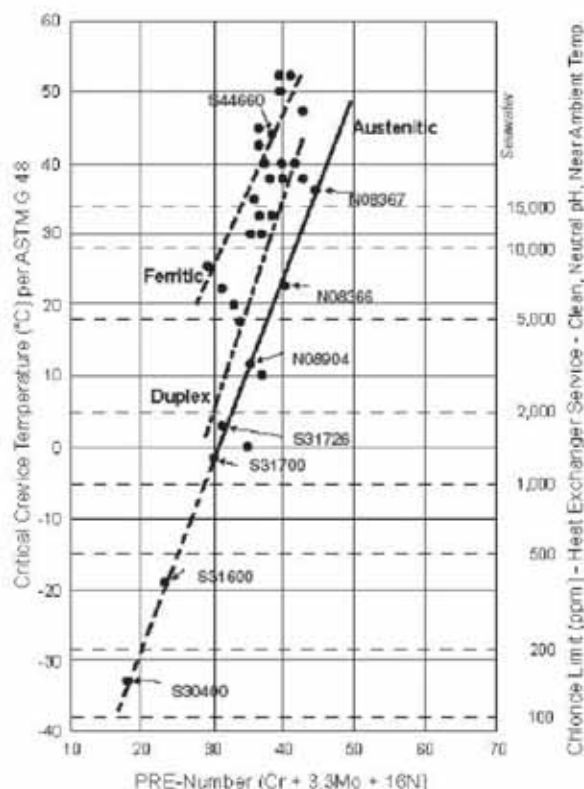
de aluminum (such as in aluminum brass) or nickel (such as copper- nickel). Absolute values of safe chloride levels for copper alloys are hard to determine as the porous patina is strongly affected by other factors such as minor pH swings, and the presence of other ions (especially sulfur). With copper alloys, iron ions in some water can have a very beneficial effect. Some utilities will add ferrous sulfate to cooling water to help protect the passive layer on these alloys.

Rockel[2] determined that the additions that provide the chloride resistance in stainless steels are chromium, molybdenum, and nitrogen. This led to the development of the Pitting Resistance Equivalent number, PREn which is defined as follows:

$$PREn = \% \, Cr + (3.3 \times \% \, Mo) + (16 \times \% \, N)$$

Kovack and Redmond[3] studied this relationship further and developed three relatively parallel relationships depending upon crystal structure. The ferritics were found to have significantly greater crevice corrosion resistance than the austenitics for a similar PREn. Understandably, the duplex grades fell in between. Janikowski[4], and Tverberg and Blessman[5] used this relationship to develop a tool to determine the maximum chloride content that should be used for each alloy. This is presented on the right hand axis of Figure 2.

Scaling potential

Scaling can cause a number of problems. The scale layer can become a thermal barrier resulting in lower heat transfer, and consequentially, in a condenser, a significant increase in backpressure. Scaling also creates a crevice at the tube surface. The reduction of the inside diameter of the tube creates a greater head loss lowering total cooling water flow. It is not uncommon for scales to reduce the calculated cleanliness factor (which is the result of the combination of reduced conductivity and lower water flow) to an equivalent HEI[6] factor of 50%. This can result in significant derating during summer months (as reported by Burns and Tsou[7]), or can show as a loss of he-

at rate in most other conditions. Although in many cases, the two can be additive for lost income, we've only addressed the heat rate below.

Since total megawatt output of many units are restricted by permit, we will use the heat rate as the major reason for operational cost increment due to scaling effects. In a conventional boiler type plant, a typical value for increase in energy needed to overcome 0.1 in. in Hg A back pressure increase is 15 BTU/ KW-Hr. Using this as a basis, following is a formula that can be used to determine that annual incremental cost due to the increase in back pressure.

$/yr = Fuel cost ($/MBTU)
* (15 BTU/KW-Hr)
* (1000 KW/ MW)
* (8760 Hr/yr)
* Plant Size (MW)/
  (106 MBTU/BTU)
* .90 (Plant Availability)

For a 300 MW gas fired conventional boiler steam plant with scaling resulting in a back pressure increase of 0.1 in. Hga, using this formula and assuming today's natural gas costs at $12/ MBTU, and assuming that the plant was operational 90% of the time (and that steam turbine was not choking), the incremental fuel cost for operating this plant can be as much as $425,700 / yr.

We have developed a hypothetical 300 MW power plant to develop the example of the incremental cost. The condenser processes 1,650,000 lbs of steam/hr with an Enthalpy of 950 BTU/lb. It has 14,000 TP 304 tubes that are 1" x .028" with an effective length of 35 feet long. It is designed with a 2 pass configuration and an inlet water temperature of 80 degrees F. The circulating water pump design provides 130,000 gal. / min. resulting in a temperature rise of 24.12 degrees F. The base design for this condenser is a 95% cleanliness factor which is a typical cleanliness for stainless steel and titanium tubing. However, as scaling starts to occur, the "apparent" cleanliness factor decreases.

We've chosen two options, coal and "oil/natural gas", as fuel for the plant. As they are competing fuels for many applications, today's natural gas and oil cost are similar, at about $12/MBTU. Coal is currently a much more cost effective fuel in most areas at $2.25/MBTU. We've also assumed that the plants are based loaded plants that are operational 90% of the time during the year. Table 1 below identifies the additional fuel costs per year due to various levels of apparent "scaling" as calculated using HEI criteria from measured back pressure . With today's fuel costs, this shows how critical it is to do whatever is needed to keep tubes clean. A combination of cooling water chemistry control and alternative cleaning methods may be justified. Today's continuous ball cleaning systems require significantly less maintenance and attention than those installed 15 years ago. With the fuel cost above, these systems may show a quick payback.

The common scales that form are calcite, silica, and gypsum. The minerals that form these scales have inverse solubility. This means that the water's ability to keep the minerals in solution decreases as the temperature goes up. If a circulation water chemistry is near the solubility limit at a condenser inlet temperature, the temperature increase along the tube length (or in higher pressure zones) can result in scale formation. This explains why many plants have increased deposits near the outlet end of the condenser. Wolf Creek Nuclear[8] is a good example of this temperature effect. The scale creates a crevice on the metal surface. If the tube alloy is above the critical crevice temperature, attack may occur. In general, the critical temperature for crevice corrosion is about 50 degrees F lower than for pitting corrosion. An alloy, like TP 304, may be safe at 100 F in an environment when the tube surface is clean (no crevices). However, when the crevice forms, the critical crevice temperature is commonly below 100 F, resulting in attack. The lower attack temperature is the result of higher concentrations of hydrogen, and

HEI Cleanliness	95%	90%	80%	70%	60%	50%
Back pressure, in. Hga	2.85	2.92	3.11	3.37	3.76	4.39
Add. Fuel cost,$/yr Coal Fired	$0	$55,878	$207,546	$415,093	$726,412	$1,229,213
Add. Fuel cost,$/yr Oil or Gas Fired	$0	$298,015	$1,106,914	$2,213,827	$3,874,198	$6,556,334

Table 1. Annual Incremental Fuel Cost for 300 MW Conventional Boiler/Steam Plant, assuming $2.25/MBTU for coal and $12/MBTU for oil or gas

chlorides and/or sulfur compounds that are driven by osmotic pressure and have no return path to the bulk water. This results in significantly higher solution aggressiveness under the deposit.

To determine the potential for scaling, the Langelier Saturation index is a good tool. It is a calculation that sums the components that drive scaling versus the acidity of the water, which can dissolve scale. In addition to the water temperature, pH a strong factor whether scaling would occur. As the pH decreases, the water potential becomes more corrosive (or will have more potential to dissolve scale). As the pH increases, the scaling potential grows. Here are the components needed to determine scaling factor:

- Water pH
- Water Temperature (use the highest or outlet temperature)
- Alkalinity (measured as ppm $CaCO_3$)
- Calcium Hardness (ppm Ca^{+2} as ppm $CaCO_3$)
- Total dissolved solids, TDS

The Langelier Saturation index, LSI, uses the following concept:

$$LSI = pHa - pHs$$

Where: pHa is the actual water pH, and pHs is the pH of the water where saturation occurs

The formulae to calculate these are as follows:

$$pHs = (9.3 + A + B) - (C + D)$$
Where:
$$A = (Log_{10}TDS-1)/10$$

$$B = -13.2 \, Log10(^{\circ}C + 273^{\circ}C) + 34.55$$
$$C = Log_{10} (Ca^{+2} \text{ as } CaCO_3) - 0.4$$
$$D = Log_{10} (\text{Alkalinity as } CaCO_3)$$

If the LSI is negative, the water is non-scaling (or will dissolve scale). If the LSI is positive, the potential is likely for scale to form.

Although a utility has little control over temperature, the factor that can be controlled is the pH. The formula shows that to reduce the potential for scaling, lower the pH. It is common to add acid to closed cooling systems to do this. Sulfuric acid is the most common addition and is rarely detrimental to stainless steels or titanium. Care needs to be taken when adding sulfuric acid to systems containing copper. As discussed later, the sulfur compounds can be a food source for certain bacteria that metabolize it into compounds aggressive toward copper alloys. Never use hydrochloric, muriatic, or other acids containing chlorides or other halides as these may depolarize the protective oxide on the various tube and pipe materials.

Acidity
Acidity, as measured by pH, is a double edged sword. As mentioned in the previous section, lower pH is good when the prevention of scaling is desired. However a reduction in pH may result in the attack of the protective oxide on the metal surface. As copper and iron can form more than one oxide, it is important to try to keep the most protective one present. In general, when water is in contact with carbon steels ,such as those used for piping, it should have a pH of 8.2

or greater[9]. Dropping the pH results in oxide morphology that has higher solubility, dramatically increasing the general corrosion rate. Copper alloys have a similar threshold.

Depending upon the PREn, stainless steels are more resistant to lower pH. Low PREn alloys, like TP 304, TP 316, and TP 439 can resist a pH of 6.0 provided the chloride content of the water is low. High performance stainless steels, like S44660, S44735, and N08367, can resist significantly lower pH combined with higher chloride content as their protective film has substantially higher resistance. Titanium Grade 2 can also tolerate very wide chloride and pH swings.

When chloride and sulfur ions are present, extreme care must be exercised before promoting a drop in pH. The combination of the lower pH with the above ions can depassivate the surface films of copper alloys, carbon steels, and many lower PREn stainless steels. Localized depassivation initiates pitting corrosion and the combination of the difference in reduction potential between the passive and active areas provides the driving force for very high corrosions rates. It is not uncommon for heat exchanger wall penetration within 3-5 weeks of initiation.

Suspended solids
Suspended Solids can be a blessing or a poison. Suspended solids can include silt, sand, silica, or organic material. If the alloy has high erosion resistance and the flow rates are high, the suspended solids can benefit the heat exchanger performance by helping to "scrub" the surface of the tube. This results in a clean and more conducti-

ve tube. Plants with river water with high sand content, such as the Missouri, have used this advantage for many years. However, this does not work well if the alloy is soft, such as copper alloys. The sand/silica acts as an abrasive and erodes the protective oxide. This requires the copper alloy to "reprotect" itself. After the patina reforms, the sand erodes it, thus repeating the cycle. The continuous cycling results in very short tube life.

Crucible Research[10] developed a slurry abrasion test to test the relative resistance to sand abrasion in "seawater" alloys. They used an impeller to propel 50-70 AFS grain silica sand at 13.6 feet/sec in synthetic seawater adjusted to a pH of 8. The test was performed for 100 hours. The results are summarized in Table 2.

In this test, the S44660 and Titanium Grade 2 had similar sand abrasion resistance (as measured by thickness or volume loss. N08367 has slightly less resistance. Cu-Ni had significantly lower resistance than any of the grades. With low flow rates, heavier suspended solids will "settle out". These create crevices at the tube bottom. Additional circumstances can aggravate the situation. When suspended solids are present during scaling conditions, the combination can be a disaster. In some conditions, a nucleation site is needed for scaling to initiate. The suspended solids provide these sites and any surface imperfection on the tube is the collection point for the deposit. The combined deposit is thicker and denser than scaling alone and the irregular deposit create potentials that initiate crevice corrosion. To prevent settling of deposits, higher velocities are needed. Optimally, a velocity of 6 to 10 feet per second is desired. Lower velocity allows the settling and entrapment of larger particles. Velocity above 10 feet per second results in a significant increase in pumping costs. Additionally, when suspended solids are present at times when bacterial slimes are on the tube surface, the slimes act as a "glue" to attach the particles. This creates a denser surface lay-

Material	Hardness (RB)	Weight loss g/cm3	Thickness Loss/Hour (x 10-6cm)
SEA-CURE® S44660	95	4.3	0.39
AL6XN® N08367	87	6.1	0.52
90 Cu-10 Ni	22	181.1	1.40
Ti Grade 2	85	2.4	0.37

Table 2. Results of Silica Slurry Abrasion Testing in Synthetic Seawater

er resulting in a more aggressive crevice.

The "organic" solids can be composed of a decayed vegetation, particles of agricultural products sourced upstream (wood particles), or in the case of reclaimed water, treated waste products from water treatment plants. In addition to being potential crevice formers, these are also potential food sources for a variety of microbiological agents to be discussed in the next section.

Biological potential

Microbiological Influenced Corrosion (MIC) is often confused with pitting corrosion and may occur in water normally considered benign. The term "influenced" is used since the bacteria alone does not normally cause the corrosion. Usually, the bacteria forms a film that isolates the water chemistry on the metal surface from the bulk water chemistry and may have a waste product that can be very aggressive[11]. Table 3 lists common bacteria types known to influence corrosion.

The most common MIC attack mechanisms in North America are the result of the influence of sulfate reducing and manganese reducing bacteria. The sulfate reducing bacteria produce a waste stream that is aggressive to copper alloys. In cooling waters, they rarely are a problem with stainless steels. However, the manganese reducing bacteria can have a disastrous result on low PREn stainless steels. Although the mechanism is complicated, following is the one most likely. The bacteria assist in the oxidation of the soluble Mn ion to form an insoluble MnO_2 layer on the metal surface. This creates a crevice. Additional chlorination intended to assist in the removal of the slime further oxidizes the layer to a permanganate. Under the layer, hydrochloric acid is formed as a byproduct of the oxidation process. The acid attacks the stainless steel. Recent studies have found that manganese concentrations as low as 20 ppb can initiate the problem[12]. This mechanism most commonly attacks TP 304 and TP 316, but higher molybdenum containing grades have also been attacked. A stainless with an ASTM G-48 method B critical crevice temperature exceeding 30 degrees centigrade is need to resist this attack. Those with a proven track record include S44660 and N08367.

Organism	Action	Problem
Thiobacillus	Sulfate Reducer	Produces H2SO4
Desulfovibrio	Sulfate Reducer	Produces H2S
Gallionella	Mn/Fe Fixer	Precipitates MnO2, Fe2O3
Crenothrix	Mn/Fe Fixer	Precipitates MnO2, Fe2O3
Spaerotilus	Mn/Fe Fixer	Precipitates MnO2, Fe2O3
Nitrobacter	Nitrate Reducer	Produces HNO3

Table 3. Bacteria Commonly Associated with MIC

Temperature

Increased inlet water temperature usually has a negative impact on most factors that have been discussed above. These include:

- Increased potential for scaling. Most of the scales have inverse solubility.
- High biological growth rates. This could be the microbes discussed in the MIC above or could be related to plants such as algae which can clog screens and cooling towers.
- Increased corrosion rates, either as general corrosion or pitting corrosion. General corrosion rates of copper alloys increase asymptotically with increasing temperature. On the 300 series stainless steels, the critical pitting temperature can be exceeded. This would change the lifetime of the tubing from over 40 years to potentially less than one year.
- Higher evaporation rates which result in increased concentration of all ions. This also increases the potential for scaling and attack.

Rarely do increased cooling water temperatures help alloy performance.

Operational Concerns

Few plants seem to have enough personnel to handle all of the day-to-day changes that occur with cooling water chemistry. Cooling water chemistry of base loaded plants seems to be easier to control than those plants that cycle. Fortunately, on base loaded plants, properties can be continuously monitored and this equipment can be used to identify any deviation that that may require operator intervention before any damage occurs. Automatic systems to adjust pH or to chlorinate are common.

Water chemistry control can be a challenge on plants that cycle or load follow. During one or more times during the day, these plants are not in a "steady state" mode and what is measured at one location may not be consistent with another. Nightly shutdowns are a real challenge. If the condenser or BOP exchangers are tubed with lower cost alloys such as 300 series stainless steel or copper alloys, it is imperative that the exchanger be drained and dried every time the unit is shut down. Allowing the water to stand stagnant in the tubes creates high potential for MIC attack and settling of suspended solids. The slimes "glue" the solids to the tube surface. After a few cycles, the deposits grow thick enough to become substantial crevice formers. Leaving a small pump on overnight does not create much benefit as the flow rate needs to be above 5 feet per second to prevent settling.

Even if the condenser is drained, care must be exercised to ensure that the condenser is rinsed with clean water and dried. If this is not done, small pools remaining in the tubes concentrate ions from the cooling water. If lower performance tubing materials are being used, the concentrations can exceed the critical levels for de-passivating the protective oxide. When it is impractical to do everything needed for a proper tube lay-up, high performance tube materials should be considered. Those with a long proven track record include S44660, N08367, and titanium grade 2. A forced shutdown during peak periods to repair a boiler tube leak caused by condenser tube leaks could justify the increased initial cost of the higher performance materials.

Seasonal effects

In many locations, water chemistry may vary significantly depending upon season. In cooling lakes that are replenished from snow thaws and spring rains, this time of year is a breath of fresh air. The additional volume of relative clean water dilutes the mineral concentrations of these closed aquifers. Conversely, a hot dry summer can concentrate these waters to the point that scaling conditions are possible at lake temperatures. The high evaporation rates at a cooling lake in Arizona has resulted in minerals precipitating on monofilament fishing line on the lake bottom.

Late winter and early spring thaws have also created serious problems for utilities in municipal areas in cold climates (see Case 1 below). During the snow thaws, road salt is washed into local rivers and storm drains. This significantly elevates the chloride levels. In many municipalities, the storm and sanitary drains are combined. The high chloride is then transferred to the local water treatment plant. Many new power plants using recycled water have based their materials selection on water snapshots typically during the summer when the chemistry was rather benign. A 10 to 20 fold increase in chloride level would not be unusual during the runoff period. These could have disastrous on the plants materials.

Root cause failure analysis

When tube failures become significant enough to consider retubing, it is important to have a qualified company perform a root cause analysis of the failure mechanism. In many instances, the wrong mechanism is assumed, resulting in selection of a replacement material that fails very rapidly. This can become a very expensive exercise. Following are some examples where such an analysis would have been beneficial.

Case 1-Because a minimal chloride was detected in the cooling water and the tubes were not made with low residual stress, a Midwestern utility made the assumption that chloride stress corrosion cracking (SCC) was the cause of failure of a number of TP 304 condenser tubes. The response was to replace the TP 304 with TP 439, a grade known for its SCC resistance. The tubing worked well until the next spring when another rash of failures occurred. At most times of the year, the river that was the cooling water source contained less than 100 ppm chloride. However, the river was the recipient of road salt run-off during the spring thaws. Chloride content of the river during these thaws was found to climb as high as 1200 ppm chloride, far above the critical pitting level for either TP 304 or TP 439. A detailed metallurgical analysis of the TP 304 tubing would have detected that the cause was pitting and not SCC. Both TP 304 and TP 439 have similar chloride pitting resistance. With these results, TP 439 would

not have been selected as the replacement alloy. An alloy with significantly greater pitting resistance, such as SEA-CURE® or AL6XN® high performance stainless steels, or titanium grade 2 may have been a better choice.

Case 2-Over the last 50 years, Admiralty brass, aluminum brass, and 90-10 copper-nickel have been successfully used in water normally not considered to be very aggressive. These grades are commonly desired when microbe fouling is considered a problem. When the conditions are favorable, the copper alloy will develop a relative porous patina that gradually allows the dissolution of copper ions into the water. These ions retard the microbe attachment and the tubes remain relatively clean. Provided that the patina layer remains relatively constant controlling copper dissolution, 20 to 30 year lifetimes are not uncommon. However, an aggressive ion, such as H_2S, can break down portions of the patina. Localized attack occurs because of depassivation of the surface and a galvanic cell develops. If this event is one that occurs 15-25 years into the tube lifetime, it is often assumed that general corrosion over the life of the tubes is the cause. This leads to the assumption that replacement tubing of the same chemistry will result in a similar lifetime. In some cases, this is not true as the event that caused failure of the tubes is the result of a permanent change in the cooling water chemistry. A metallurgical analysis of the original failed tubing would have revealed that the actual failure was pitting related, not general corrosion. Combined with a detailed water chemistry history, the analyst could have discovered a link between the changed water chemistry and the pitting. When pitting occurs, it is not uncommon that from the time of initiation to tube perforation may be only a year or two. During stagnant conditions, .028" wall TP 304 can perforate in 3 weeks. To prevent a reoccurrence, a resistant grade to the corrosion needs to be selected.

Case 3- TP 304 tubing had an excellent 25 year track record in a Midwestern power plant after replacing Admiralty brass that failed quickly from erosion corrosion due to high water velocity of 8.5 feet per second. The plant employed once through cooling from an adjacent river. After the 25 year span, the tubes started leaking and the utility replaced the TP 304 with tubes of the same grade because of the history. The new tubes started failing in less than 2 years. An analysis on of the tubes showed high manganese deposits on the inner surface indicating that the failures were probably due to corrosion resulting from manganese reducing bacteria. An analysis of the previously failed tubes would have shown a similar results suggesting that TP 304 may no longer be the proper material for this river chemistry. With changes in EPA requirements and the closing of many manufacturing facilities in North America, many of the rivers are becoming cleaner. Unfortunately, the cleaner water was no longer inhibiting microbiological growth. The utility has now chosen S44660 SEA-CURE® to address their problem.

Summary for dealing with tough conditions

Sooner or later we will need to deal with tough situations. It's best to be prepared for them in advance.

Here are some suggestions:

1. Have a detailed procedure for lay-up practice after shutdown. This should include draining the condenser, flushing with condensate, and drying. For marginal alloys, this is imperative to prevent the initiation of pitting and MIC related corrosion. They need to be kept clean for longitivity. For high performance alloys, such as N08367, S44660, or Ti grade 2, the need to keep them clean is for optimal thermal performance. If shut down for short periods of time, keep the pumps going at higher velocity. Very low flow rates allow settling of suspended solids and the formation of slimes.

2. When considering new materials, assume worst case chloride levels. Plan for concentrations due to high evaporation (summer conditions), or due to road salt run off.

3. If the potential for MIC exists, chose a proven resistant grade, such as N08367, S44660, or Ti grade 2. Assume that at some point in the condenser lifetime that the conditions will occur for slime formation.

4. Do a detailed root cause analysis on condenser tube failures. In general, if you find consistent wall thinning through out the entire tube, the failure probably gradually occurred over the life of the tube. If you find pitting or localized attack, it possibly occurred in the recent history. Do not assume that pitting occurred gradually over 25 years. The cure is to eliminate the cause or select a more resistant material.

5. If you are using eddy current testing for determining the condition of the tubing, it is essential that you validate the test by removing a tube and measuring the actual size of the defects. In many cases, a 90% deep flaw is much shallower (resulting in prematurely plugging tubes). The opposite can also be true.

Conclusion

Cooling water is a necessary "evil" that we need to deal with and it is become shorter in supply. The World Wildlife Federation has summarized water's future as becoming the "new oil"[13]. To address the problems with our water, we have a choice using careful materials selection or using operational "tricks" that we can use to make our lives easier. However, in some cases, the water that we need to live in harmony with may be too aggressive for the traditional "lower priced" alloys. When this occurs, it may be most cost effective to consider a high performance tubing material.

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ACKNOWLEDGMENTS

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SEA-CURE®
Comparative Properties for Aggressive Cooling Water Candidates

Property	SEA-CURE®	Ti Grade 2	90-10 Cu/Ni	AL6XN®
Ultimate Strength*	85 ksi	50 ksi	40 ksi	100 ksi
Yield Strength*	65 ksi	40 ksi	15 ksi	45 ksi
Elongation*	20%	20%	25%	30%
Rockwell Hardness**	Rc 25	Rb 92	Rb 20	Rb 100
Modulus of Elasticity (x10^6 psi)	31.5	15.4***	18.0	28.2
Density	0.278	0.16	0.32	0.29
Thermal Expansion	5.38	5.2	9.5	8.7
Thermal Conductivity	9.9	12.5	26.0	7.9
Fatigue Endurance	35 ksi	16 ksi	25 ksi	33 ksi

*   Minimum ASTM Value
**   Maximum ASTM Value
***   Average of Longitudinal and Transverse

More SEA-CURE® information is available at **www.seacuresolutions.com**.

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