Because of accelerated corrosion in raw water systems at nuclear power plants, piping often must be lined to check corrosion. Linings are usually installed in-place, although some raw water piping and components can be lined in the site maintenance facility or even in an offsite shop. Coatings and linings have often been applied to tubesheets and channels of heat exchangers in conjunction with retubing to prevent galvanic attack. Unfortunately, in the USA, lining application work often does not meet the high standards expected in nuclear programs. Process controls critical to the success of lining installations are often misunderstood or inadequately addressed.

This article describes problems and procedures in the U.S. nuclear power generation industry; however, the good practice advice on re-lining service water pipework is relevant to operators everywhere. This article first reviews the use of linings in service water systems (SWS). It then describes the need for improved lining performance in these settings, and it notes concerns about linings voiced by the U.S. Nuclear Regulatory Commission (NRC). The remainder of this article reviews the process controls essential to optimising service life. These include:

- surface preparation considerations;
- detection and elimination of residual surface contamination;
- application and curing of linings; and
- special requirements and procedures for controlling water leakage, eliminating microbiologically-influenced corrosion, and optimising work procedures.

SWS linings represent the largest category of safety-related coatings outside containment. Revision 1 of the NRC’s Regulatory Guide (RG) 1.54, which addresses safety-related coatings, is pending. The existing version addresses only containment coatings. Revision 1 will reference ASTM D5411-2000, Standard Guide for the Use of Protective Coatings Standards in Nuclear Power Plants, which formalises for the first time the existence of safety-related coatings inside and outside containment. It is anticipated that Rev. 1 of RG 1.54 will link Appendix B (of the U.S. Code of Federal Regulations, Part 50, Power Plants) QA/QC protocols already established for containment coatings to safety-related coatings and linings outside containment.

History of and Basis for Service Water System Linings

Corrosion control with liquid-applied linings and, to a lesser extent, with sheet linings for maintaining service water systems is an important aspect of maintaining SWS operations. Once-through systems of coastal plants were often designed to include shop or construction-phase linings. Plants with man-made ultimate heat sinks that use open-cycle systems were most often constructed with un-lined carbon steel systems. (Once-through/open-cycle systems use cooling water from an ultimate heat sink such as a river, lake, or ocean. After passing through a heat exchanger, the water returns to its source.)
Lining Types

Various lining materials have also been used, including cement linings and elastomeric polymeric coatings. The linings have been applied in the shop and in the field during the operating phase. Cement linings were typically installed in cast iron and carbon steel piping. Polymeric coatings were applied in the shop or field during construction of some saltwater-sited plants, while a few once-through cooling systems were fabricated from alloy.

Application of coatings during the operating phase of the plant has been required for a variety of reasons. Originally installed linings have a finite life. Achievable service life depends on factors such as water temperature; velocity; turbulence; type of fouling; and frequency of, and methods for, removing fouling.

“Cement” mortar (concrete) linings have a number of advantages. They increase in strength over time, particularly over the first few years of service. The cement-to-metal interface is maintained at a high pH, which passivates the steel, stopping corrosion. Because the cement is applied as a thick layer, it will tend to stay in place due to “arching” (“keystoning”), even if the bond to the metal becomes broken due to water hammer (or sudden shut-off of the water) and similarly disruptive system flow dynamics.

A disadvantage of cement linings is their tendency to hide sub-lining corrosion problems. The passivating effect offered by the cement is diffusion limited, i.e., the alkalinity will leach out of the interstices with time, and corrosion will occur under the cement lining. The corrosion product is shielded from view and can build up to such a volume that chunks of cement spall. The disbonded chunks can create substantial damage as they hit downstream pipe, valves, and heat exchangers. Another disadvantage is that concrete is intrinsically weak in tension. Cement linings have relatively limited life in portions of systems subject to sudden depressurisation and partial vacuum such as are associated with water hammer conditions. Typical of most types of shop-applied linings, joints in cement-lined pipe are field-applied after pipe installation, and the joints are frequently the least reliable portions of the lining system.

Elastomeric linings such as natural and synthetic rubber have also found wide application in seawater and some river- and lake-supplied raw water systems. While the process industries discovered the importance of using different hardnesses of rubbers when lining pipe spools to avoid squeezing out the lining (detrusion) at bolted flanges, this practice was not consistently transferred to the power industry. Usually, soft rubber was used in power plant cooling water systems to line the entire spool, including the flange face. Compressive stresses that developed across the flanges caused the rubber to flow, creating a bulge that narrowed the internal diameter (ID) adjacent to the joints. The rubber at the cervical ID restriction is subject to dynamic stresses that ultimately cause the rubber to tear; rapid corrosion usually follows. This problem could be avoided by designing the flanges of pipe spools and lined vessels like strainers and condensate polishers with hard rubber flange faces.

Many types of shop-applied linings must be field-prepared at the joints. Such is invariably the case with field-welded pipe spools. The joints of flanged sections are not immune from lining degradation because of the stresses and strains associated with bolt-up. One advantage of cured-in-place (CIP) linings is that such installations intrinsically limit the number of lining joints. Obviously, even CIP linings require joints at some points, and these, too, have proven vulnerable to degradation. Insufficient attention to detail in the design of joints in lining systems contributes to lining degradation and the need for repair.

Maintaining and Lining Unlined Pipe

Most open cycle nuclear service water systems were installed as unlined carbon steel. Over time, corrosion byproduct, scale, and fouling contributed to corrosion. In the USA, non-flow-accelerated corrosion (non-FAC) has attained a sufficient level of concern with respect to system availability/reliability to prompt owners to institute wall thickness monitoring programs. Internal corrosion of raw water pipe can, for a given pumping head, substantially
reduce flow and can contribute debris. Internal pipe corrosion fosters slime and scale. This build-up, in turn, can harbour microbial organisms. Under-deposit pitting, frequently enhanced by MIC, is common in most raw water systems (Fig. 1).

During a plant’s operating phase, linings are applied to previously unlined pipe and components for a variety of reasons. Often, portions of a system will be lined to minimise fouling, to enhance the efficiency of the fouling removal processes, and to retard corrosion. When SWS heat exchangers are retubed (Fig. 2), the tube material is often upgraded to avoid pitting. It is not uncommon for more noble materials such as stainless steel and titanium to be substituted for copper alloy materials. Substituting more corrosion-resistant alloys changes the galvanic “equation” that governs the materials of construction for a heat exchanger and can result in attack of tubesheets and channels (Fig. 3). Polymeric coatings such as liquid-applied, solventless epoxies have found wide use in lining portions of heat exchangers, valves, and other SWS components. The linings protect the original fabrication materials when retubing heat exchangers with more noble materials or when upgrading the metals used in parts of the systems.

Even SWSs fabricated from corrosion-resistant alloy are not immune to degradation. As indicated in Fig. 4, one plant found 90/10 copper-nickel to undergo excessive erosion. As a result, much of that system was lined with an epoxy shortly after start-up.

The specific need for careful and effective maintenance of SWS linings has been established in the “Recommended Actions” of Generic Letter 89-13:

*Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting and biofouling cannot degrade the performance of the safety-related systems supplied by service water. The maintenance program should have at least the following purposes:
  * “To remove excessive accumulations of biofouling agents, corrosion products, and silt;”
  * “To repair defective protective coatings and corroded service water system piping and components that could adversely affect performance of the intended safety functions.”

**Reliability of Linings in Raw Water Service Needs Improvement**

Lining application is not technically complicated when compared with many of the maintenance functions regularly performed at nuclear power plants. Nevertheless, repairing and rehabilitating or reinstalling linings is often improperly performed. Rework of degraded cooling water system linings has become routine at many facilities. Typically, coatings applied or repaired during the prior refueling outage are expected to need and scheduled for, repair during the next outage.

This expectation of inferior lining performance has become ingrained in the culture of many plants’ engineers and maintenance and planning personnel. Such poor expectations with respect to the serviceability of linings are not tolerated in other industries where lining performance is critical to operations. In the process and pipeline industries, for instance, corrosive materials under high temperature and pressures are contained and transported with a high expectation of favourable lining performance and freedom from corrosion. The lining installation proficiency within those industries has evolved over time.

Process industry engineers have participated actively in technical committees aimed at translating lessons learned into effective standard practices and procedures. They have been motivated by the need for lining quality to ensure cost-effective operation as well as worker and public safety. NACE International has long championed good design and installation practices for corrosion resistance and lining application. While the publications of NACE International have been adopted by the petrochemical and process industries, the power industry has been slower to adopt them. As a result, most nuclear power plants have been slow to recognise the need for a coating specialist or coatings engineer to oversee coating and lining work. Lining maintenance work in the nuclear power industry has consequently been performed inconsistently and has resulted frequently in deficient and substandard material performance.

In an effort to redress shortcomings with the technology of power plant coatings and linings, ASTM Committee D33, Protective Coating and Lining Work for Power Generating Facilities, was established in 1980. The objective of ASTM D33 has been to deliver high quality standards...
to ensure that critical coating and lining work could meet appropriate technical requirements and processing procedures. Committee D33 spawned a group of nuclear utility coatings engineers known as the Nuclear Utility Coatings Council (NUCC). NUCC, now supported by the Electric Power Research Institute (EPRI), is dedicated to enhancing awareness of proper materials, practices, and intra-industry education in the technology of protective coatings and linings.

U.S. Regulatory Concerns Regarding Performance of Safety-Related Coatings and Linings

The NRC’s awareness of the performance inadequacies of SWS linings has been evident in the regulators’ increasing concern about the impact of degraded linings on system availability and reliability. Those concerns are made manifest in Information Notices (INs) 94-57, 95-02, and 97-13. These events and a host of Licensing Event Reports (LERs) relating to degraded coatings within containment have caused the NRC to refocus on the issue of potential sources of debris. These concerns and the process of revising Regulatory Guide 1.54, which imposes the Appendix B Criteria with specific respect to safety-related coatings and linings, led the NRC to revisit certain quality assurance and design issues. The vehicle for assembling the background information the NRC needed was Generic Letter (GL) 98-04. GL 98-04 included the following line of inquiry:

- What programs are in place to ensure ongoing implementation of licensing commitments?
- How are 10 CFR 50.46(b)(5) long-term core and containment cooling commitments secured? Specifically, how do screen/strainer designs account for paint debris? Do the screen designs reflect debris expectations predicated on maintenance rule policies (i.e., 10 CFR 50.65, mandated periodic condition assessments with repairs as required)?

GL 98-04 deals solely with issues inside containment (traditionally referred to as “Service Level I or SL I Coatings”). EPRI TR-109937 addresses safety-related coatings outside containment (i.e., those referred to as “Service Level III”) in addition to SL I coatings. These coatings were included because of the NRC’s concerns regarding linings for components used in heat removal systems essential to achieving and maintaining safe shutdown. The design, process, and quality concerns regarding the impact of failed coatings and linings are inextricably linked regardless of whether the source location of the potential debris is inside or outside containment. To date, the NRC has not polled licensees regarding SWS linings design and maintenance policies to ensure the reliability of Service Level III coatings. It seems, however, that similar concerns with respect to clogging of SWS heat exchanger...
tubesheets and flow constrictions (orifices, strainers, etc.)—in other words, SL III systems and components—will ultimately need to be addressed.

Recognizing that licensees would need guidance in formulating their response to GL 98-04, the Nuclear Energy Institute (NEI) encouraged the Electric Power Research Institute (EPRI) to compile a resource that would review safety-related coatings regulations and the standards available to facilitate compliance. The NRC actively supported the development of such guidance and agreed to defer issuance of GL 98-04 until the EPRI guidance, TR-109937,9 was published.

Revision 1 of Regulatory Guide 1.54 was issued in July of 2000. The revised guide references newer ASTM standards devised to replace withdrawn ANSI standards referenced in the original RG 1.54 as well as standards that were not available until recently. A key ASTM standard, revised last year, is ASTM D5144-2000. This standard is pivotal to the NRC’s expectation that the industry compile a compendium of all ASTM nuclear coating and lining standards. In fact, the NRC held up publication of the RG 1.54 revision so that D5144 could be updated. The revised Regulatory Guide clarifies that Service Levels I and III are safety-related and deserving of a commensurate level of design and quality control. The ASTM standards generally recognised as applying to containment coatings (Level I) are indicated, where appropriate, as to be equally applicable to safety-related coatings outside containment (Level III). The confusion over “Level II” coatings (coatings for facilitating decontamination) has been eliminated by a statement in the revised D5144 establishing that this category of coatings is not safety-related.

Surface Preparation Considerations

Fouling Removal

For SWSs, the initial step of the cleaning process generally entails removing macrofouling. Bulk fouling is removed with scrapers and shovels. High-pressure waterjetting8,10 is often used to remove stubborn fouling such as barnacles and clams. In the USA, environmental regulations require the effluent organic biota (biomass like shells, bivalves, and fish) and water to be captured and disposed of per plant waste permit criteria.

At this stage, a “rough blast” is generally performed so that the extent of any metal repairs or grinding will be evident. Sharp edges should be faired and rounded, and deep pits should be opened by grinding. Grinding will entail design engineering’s assessment of ASME (American Society of Mechanical Engineers) code implications. When tubesheets are being coated in conjunction with retubing, rolling lubricants, if allowed, should be water-soluble. Lubricant residues must be removed by pressure washing. Note that this process as well as peroxide disinfection, or de-salting processes with steam or high purity water all can reintroduce water into the tubes. This water must be removed before proceeding.

Abrasive Blast Cleaning

The next step is abrasive blast cleaning. Abrasive low in crystalline silica, such as Class A (1%) per SSPC-AB 1,11 should be required. Industrial slag abrasive is suitable for routine lining work. A common slag abrasive (coal slag) is produced at fossil plants as a by-product of bottom ash. Some plants use saltwater to sluice the slag, and thus the abrasive may have elevated chloride levels. Section 4.1 of SSPC-AB 1 references appropriate tests to ensure that the abrasive is clean enough for immersion service lining work. Particularly hard metals, including stainless steel, cannot be cut to the profile necessary for proper bonding with a lining unless an extra hard profiling abrasive such as garnet or aluminium oxide (Al2O3) is used. (Note that aluminium oxide can often be more radioactive than is allowable at a plant.) The blast to create a profile is usually the last step in the surface preparation process.

Before lining application begins, the enclosure (Fig. 5) must be totally disassembled and cleaned to keep grit residues out of the fresh lining material. All tarps and folds must be opened and unsealed. Scaffold pipe clamps can hide grit; these need to be loosened and hammered to release abrasive.

Papers presented at a number of prior EPRI-sponsored condenser and service water symposia contain valuable guidance with respect to selection, installation, and repair of linings for open cycle raw water systems.12-15

Detecting and Eliminating Residual Surface Contaminants

Unless detected and thoroughly removed, invisible surface contaminants can cause premature lining failure. The most common surface contaminant encountered within SWSs is sodium chloride. In coastal plants, piping and heat exchangers must be flushed with clean (e.g., potable), fresh water. Unfortunately, maintenance crews
often simply dewater, force dry, and begin abrasive blast cleaning without considering residual surface chlorides. Chlorides are present in all water, including lake and river water. Unlined carbon steel in fresh water is usually covered with a layer of corrosion product. The corrosion creates a constellation of corrosion cells that electrochemically attract and concentrate chloride ions. Consequently, elevated residual chloride entrainment in metal substrates is a concern in virtually all SWSs.

For seawater systems, effective chloride decontamination requires

• removal of macrofouling,
• a rough abrasive blast to open the metal surface to treatment, and
• a condensate-quality soak or steam bath for at least 12 hours.

The effectiveness of the chloride abatement process should be checked with one of the commercially available field test kits. The varieties and attributes of the more common of such test methods are documented. It is often necessary to repeat the third step several times, particularly on castings.

NOTE: The corrosion product that forms on cast iron is graphite. Graphite is most readily removed immediately after the system in which the cast iron is located is taken out of service. Steps should be taken to keep the graphite wet as close as possible to the time the graphite removal process begins. Gross deposits of graphite are best removed by pneumatic chisels. “Fine tuning” during the abrasive blast process can then follow to remove residues in pockets.

One of the most common chloride detection methods uses concentration indicator strips. Pure water of a known volume is swabbed over a defined metal surface area or extracted from a sleeve or cell with known volume and known area. These techniques allow the chloride concentration to be reported in terms of weight of chloride per unit area. The sensitivity of the test strips varies. The chart enclosed with the particular strips being
used should be referenced when converting the gradations on the strip to parts per million (ppm). While some research has been done to establish an allowable chloride concentration value, practical experience suggests that when using the concentration strip method, the surface may be deemed essentially chloride-free if the strip reading is at or below the “1” gradation. Another method of chloride detection uses an ion detecting tube with higher sensitivity than the indicator strips.

**Application and Curing of Linings**

*Ambient Controls and Application Requirements*

Work schedules in a nuclear plant should not be subject to the vagaries of the weather. Assuring stability of the indoor conditions can be challenging. The weather inside the plant directly and quickly reflects outdoor conditions. The work environment is variable. The ambient air is mixed and changed by HVAC cycles, opening and closing of doors, and turning on equipment. Because plant personnel responsible for quality control often have little training in coatings, it is not always evident to them that ambient conditions do not meet application requirements. A freshly coated surface may cool to below the dew point of the surrounding air, and the resulting film of condensed moisture may be too thin to be visually detectable. Such a circumstance is believed to have caused a chemical reaction on the surface of an initial coat of an epoxy SWS lining. That reaction is believed to have impaired the bond of subsequent coats to the extent that substantial amounts of lining material eventually detached. In that instance, the ensuing action request required a safety evaluation that ultimately resulted in an unresolved safety question.

Most types of organic materials used when installing or repairing linings in SWS spools and components require an explicit set of ambient conditions to meet reasonable service life expectations. These conditions include

- the temperature of the surface to be lined or coated,
- the ambient air temperature,
- the dew point of the ambient air temperature, and
- the relative humidity of the ambient air temperature.

Each of these parameters has a potentially significant influence on the chemistry and physics that interact as the coating film contacts and merges with the substrate, develops adhesion, and cures. Before the inspection hold point, these conditions must be met so that the surface of the metal is satisfactory for application. These conditions must also be maintained continuously up to the point when the material has reached a defined extent of cure.

**Controlling and Containing Air Movement**

Work should be planned with the expectation that the environment in the work area will be controlled within the prescribed limits at all times. The expression “process air” is used to refer to the air supply that is prepared and treated to satisfy the ambient condition criteria. The following elements are the minimum required to deliver suitable process air:

- an essentially air- and dust-tight enclosure to isolate the work area from the plant and environment,
- dehumidification equipment (desiccant or air conditioning devices), and
- a dust collector.

Enclosures typically are fabricated from reinforced tarps on a frame of scaffold stock or fire-retardant wood. For major projects, relatively large enclosures can be constructed in a secure, centrally located indoor area such as a service bay, or outdoors if space limitations and weather conditions permit. Pipe spools, valves, end bells, and channel covers can then be detached and brought to the enclosure for processing. However, many components and pipe segments cannot be readily disassembled. These must be worked on in place (Fig. 5). The enclosure is most effective if outfitted with an ante-chamber or “air-lock” so that gross changes to the environment within the enclosure are avoided as personnel move in and out.

Consideration should be given in designing enclosures to approximate a balance between (1) inbound process air and blast air and (2) dust collector exhaust. Which is to exceed the other depends on the phase of the work. During blasting, it is appropriate to exhaust more air than is supplied to induce a modest in-leakage of air and thereby preclude dust leaks outside the enclosure. During the application phase, slight overpressurisation of the enclosure will insure a surplus of process air in the enclosure. NACE and SSPC have drafted a joint guidance document on selecting suitable equipment and integrating that equipment into an effective process air delivery and containment system.17

**Curing the Applied Lining**

A freshly applied polymeric lining material is sensitive to moisture and can be compromised by exposure to elevated moisture levels or premature immersion. There is usually pressure on the responsible engineer to return a component to service. However, the engineer must obtain the material manufacturer’s recommendations about the extent of cure required before returning a freshly coated component to service. The degree of cure achieved within polymeric lining materials is temperature and time dependent. Ideally, such criteria will be based on objective testing performed by or for the manufacturer that validates the sufficiency of the cure for a particular set of durations and temperatures. Such testing might include the Atlas Cell test described in 4.5.1.1 of EPRI TR-109937 7 to validate that immersion performance will be satisfactory.

The time to reach a satisfactory cure can be accelerated
by heating. This is commonly achieved with in-line electric or propane heaters in ducting attached to the work enclosure. Radiant heating using banks of infrared or other incandescent bulbs has been used but is less than ideal for complex surfaces due to shadowing, which occurs when any physical projection between the bulbs and the surface blocks the light. Too much heat introduced too soon can cause film stresses that will reduce service life. Heat introduced to achieve an accelerated cure should be removed gradually. The duration over which a component needs to be maintained at the recommended cure temperature and a ramp-up/ramp-down rate (rate of increase and decrease in temperature during curing) needs to be established with the lining manufacturer.

Objective evidence of an adequate cure should be obtained. Portable devices that afford quantifiable measurement of surface hardness are useful in assessing the extent of cure. These devices are predominantly gauges that work by indenting the surface, such as durometers (ASTM D2240)\textsuperscript{18} and the Barcol E Impressor (ASTM D2583).\textsuperscript{19} Solvent rub testing is another convenient means of determining the sufficiency of cure (ASTM D5402).\textsuperscript{20} For any of these tests to be meaningful, the relationship between the degree of cure associated with a measured value and immersion performance potential must have been established.

**Special Requirements and Procedures**

**Controlling Water Leaks**

Too many times a job will have progressed satisfactorily through the surface preparation phase only to have the surface or freshly applied coating ruined by unexpected water inleakage. Informed planning can usually avoid or at least minimise such occurrences. Reviewing the system to assess potential sources of water should be a part of the planning. Potential sources can include

- intake bays, vertical circulator pump columns, and headers subject to flooding as a result of exceptional astronomical tides or river flooding;
- leakage at isolation valves (isolation by positive ‘blanking’ would be preferable);
- sweating (condensation) when ambient air is damp and warm, and isolated cooling water on the other side of the isolation valve or blanking plate is cold (a problem in Pacific Coast and Northeast coastal plants); and
- water released when lateral pipes and dead legs (portions of piping systems routinely seeing no or low flow) are suddenly vented.

Anticipating leaks at these and other points allows for preventive measures such as pneumatically secured closures (“hydro-plugs”) and plumber’s balls or sandbag dikes drained by a level-actuated pump such as a sump pump or pneumatic diaphragm pump.

One chronic source of troublesome outleakage on tubesheets or channels is water trapped within the tubes. Standard treatment is to blow compressed air through the tubes. However, this treatment is often only partially successful for a variety of reasons. Heat exchanger tubes are rarely dead level or sloped. If the tube has a low spot in its length, water may remain in there, where the compressed air cannot eject it. When blowing tubes with compressed air, it is easy to miss a tube without an effective indexing system. A single tube can trap enough water to ruin the efforts of a crew applying a lining during one shift. The most reliable method of removing tube water is an enhancement of the compressed air blow-down technique. This technique involves squeegeeing the length of the tube and providing a reliable visual indexing system that ensures no tube is missed. This concept is seen in Fig. 6. One ball or a pair of sponge balls is placed in each tube. The balls swab moisture from the tube and mark which tubes have been cleaned and which have not.

**Eliminating MIC**

Microbial activity on and within the substrate can be considered a form of contamination. Microbiologically-influenced corrosion (MIC) can affect any metal. Experience shows, however, that power plant raw water system components made from mild carbon and stainless steel are particularly prone to MIC attack and surface residues. Testing performed by the author suggests that rigorous abrasive blasting of water-side corroded mild carbon steel infested with extensive microbial activity will effectively eradicate the bacteria. Abrasive blasting, however, cannot be relied upon to remove microbes from stainless steel. MIC attack of stainless is along grain boundaries or develops in cul-de-sac voids beneath the surface of the metal. MIC is thus effectively shielded from scouring and removal in the blast process. Consequently, in the case of stainless substrates, eradication is a somewhat more complex process compared with mild carbon steel. Considerable effort is needed to open the stainless steel surface before disinfecting it. Kits are available that allow for culturing and identifying particular bacteria known to relate to MIC and for quantifying population densities.

Over the years, the practical way to proceed has been to assume MIC is present and to incorporate abatement strategies in the lining maintenance sequence. For carbon...
steel, the surface should be sprayed with a disinfectant after a preliminary blast that removes most of the corrosion by-product. Hydrogen peroxide and methyl ethyl ketone (MEK) are commonly used disinfectants. MEK has the advantage of not oxidising the freshly cleaned substrate, but it presents health and fire hazards. Hydrogen peroxide is effective, inexpensive, and relatively safe. It can be purchased in bulk and diluted, or it can be purchased in normal consumer packaging (plastic bottles) at 3% and then diluted ten or more times.

For stainless steel substrates, it is common for welds and parent metal to be so riddled with MIC pockets that outright replacement of welds and considerable grinding to open pockets on plate surfaces will be required. Air arcing has proven an efficient means of removing stainless welds. The process uses electric current to create enough heat to melt the metal off; compressed air then blows it off the surface. The surfaces then receive the needed metal repair, after which a rough grit blast is performed. At this juncture, steam is introduced to eliminate bacteria by pasteurisation. The steam bath effectively sweats out chlorides at the same time. A case history detailing a project where stainless cooling water components engulfed by MIC were disinfected and rehabilitated with an epoxy lining is available.\(^{21}\)

**Optimising Procedures**

According to Rev. 1 of RG 1.54, application of linings to portions of SWS upstream of components essential to achieving and maintaining safe shutdown for both normal (e.g., fuel cooling) and accident conditions must be performed per Appendix B criteria. The nuclear industry views safety-related coating and lining work as a special process. A special process is one in which interim in-process controls are required in addition to final inspection to ensure quality. 10 CFR 50, Appendix B, Criterion IX, Control of Special Processes, mandates the existence of lining application procedures and protocols for qualifying personnel applying the material and inspecting the work. Most nuclear plants’ procedures for coating and lining are intended to cover all foreseeable end uses for that procedure. In reality, however, each work order entails a distinct set of process circumstances. It has been observed that the more successful procedures incorporated into individual work packages reflect and underscore these unique aspects of a job. This objective is met by
placing a template in the work order (prefacing the approved procedure). The template requires work planning to obtain the responsible engineer’s input about the special features of the work under consideration. The template can be thought of as a work customisation checklist or WCC.

Conclusion
If the above procedures and processes are adopted, they should help plant personnel improve corrosion protection and meet U.S. regulatory requirements.

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