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VOLUME **40**

Structural Integrity Associates, Inc.®

NEWS & VIEWS

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INSPECTING OLD, LARGE, INACCESSIBLE PIPING SYSTEMS PG.32

Structural Integrity Associates, Inc.®

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I'm sure most of you read News & Views looking for interesting technical topics, either directly related to your work or new topics you're not that familiar with yet. We certainly hope that you learn from these articles and are able to apply new knowledge in your job. I want to share with you a variety of other things going on at Structural Integrity that are also intended to help you be more successful in your career. After all, our belief is that the better you understand what we offer, the better partner we can be to help you solve the energy industry's most demanding challenges.

As you know, a hallmark of Structural Integrity is our approach of a fully-integrated offering. Very rarely can a problem be solved with a single discipline, whether it be materials science, analytical techniques, or inspection technologies. With that in mind, we're always looking to add new capabilities that strengthen all of our products. In early 2015, we acquired Finetech, Inc. to dramatically increase our chemical engineering depth. While Finetech specializes in nuclear plant boiling water reactors, we fully intend to grow our chemistry experience to reach into the full nuclear market, while expanding upon what we have in fossil and oil and gas. As we broaden our capabilities, we expect you'll find that you can come to us more often as the premier one stop solution provider.

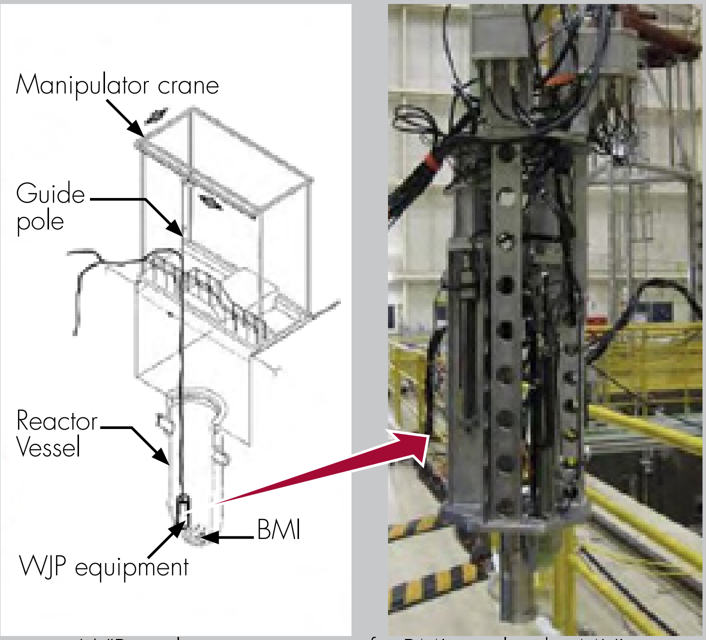
We made another move in 2015 geared towards being more responsive to client needs – the creation of a client training program. Our observations of the energy industry over the last 30+ years highlighted the current need for more extensive training programs across the industry. Our goal with the training program is to create a win-win solution for Structural Integrity and our clients. Clients receive high quality training and we get to work with more informed clients who understand the industry's issues and challenges through our experienced lens.

One of our core values and a cornerstone of our brand is a focus on continuous innovation. Innovation has served us well over the years, with the best examples being highlighted over the years in this newsletter. Admittedly, we haven't been driving innovation as much as we should recently, so to reinvigorate and emphasize our innovation and technology development, we've kicked off a strategic development initiative this year to do just that. The outcome will be new tools, products and solutions to better solve your issues and create additional value in the near-term and long-term.

I'm excited about all of the recent developments at Structural Integrity, especially those that might not be so apparent to those outside the company. But with a focus on providing best in value and fully-integrated solutions to all of our clients, everything we do is geared towards optimizing the safety, availability, and reliability of your most critical components. We'll be there with you every step of the way.

STRUCTURAL INTEGRITY OFFERS TURNKEY SOLUTIONS

MNES Completes Integration Testing for Water Jet Peening

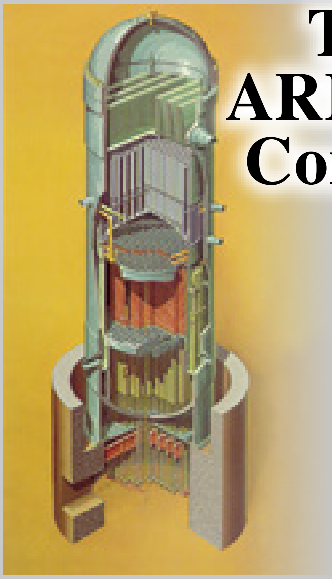


WJP application equipment for BMI nozzles, by MHI

Mitsubishi Nuclear Energy Systems, Inc. (MNES) has successfully completed equipment integration testing in Kobe, Japan as part of an upcoming Water Jet Peening (WJP) project this fall. The WJP process is an Alloy 600 stress corrosion cracking mitigation technology with 15 years of proven field experience and 45 unique applications performed at 21 different Japanese PWRs by Mitsubishi Heavy Industries.

The MNES team conducted the test in a full scale, 68-foot deep pool simulating the reactor cavity. Reactor vessel nozzle and bottom-mounted instrumentation nozzle mock-ups were peened repetitively for the testing. The MNES team is scheduled to conduct the WJP for the first time in the U.S. in fall of 2016 at the Wolf Creek Generating Station. The MNES team includes Structural Integrity which supported select engineering and licensing tasks for the project.

Teaming with AREVA to Offer Complete BWR Solution



Structural Integrity Associates has a history of aligning with other leading companies to provide the industry's most advanced turnkey solutions. AREVA is the latest company to join our prestigious list of partners.

In February, we teamed with Areva to offer comprehensive vessel internal repair solutions to the U.S. boiling water reactor (BWR) fleet. By leveraging complementary strengths in the analysis and repair/replacement of BWR vessel internals, our team offers clients unmatched value and expertise.

Our advanced analytical capabilities can help utilities implement various aspects of BWR Vessel and Internals Project (BWRVIP) Inspection and Evaluation Guidelines, including proactive analysis, outage preparation, and repair/replacement reviews.

With expertise spanning the entire nuclear fuel cycle, AREVA offers world-class design, manufacture and installation capabilities for jet pumps, feedwater spargers, core spray piping and other key components.

Working together, we will provide onsite and offsite engineering analysis, repair and replacement of BWR vessel internals, and regulatory insight to safeguard the integrity of critical reactor components and systems.

We are proud to offer BWR owners the next level of value and service. To learn more, visit www.structint.com and us.areva.com.

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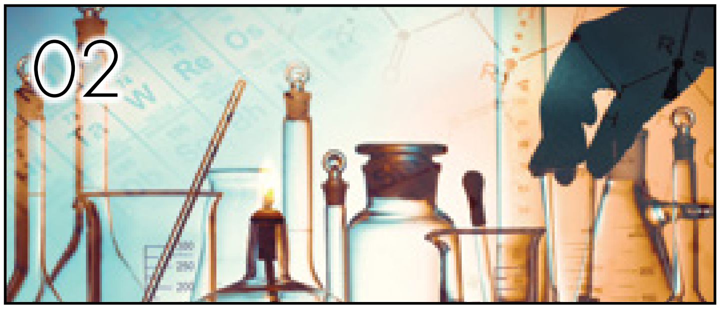

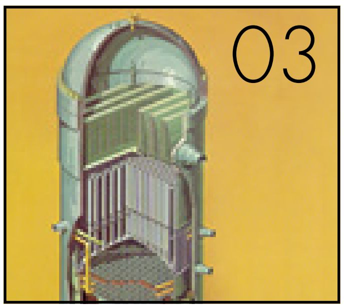

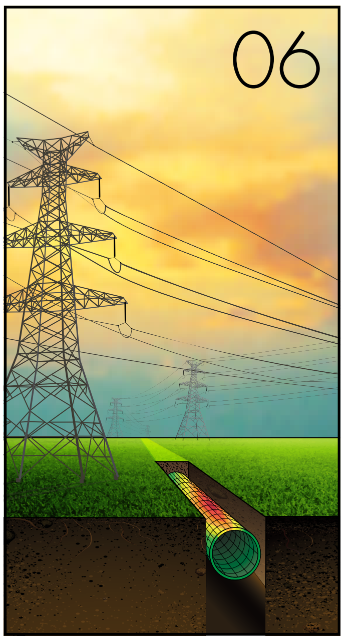

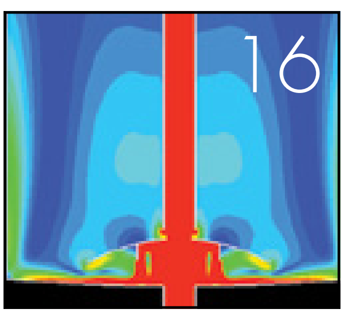

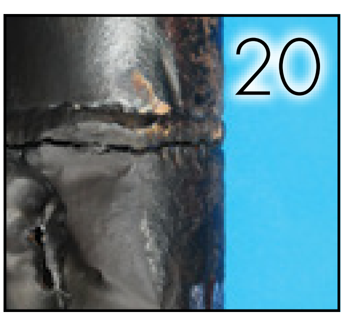


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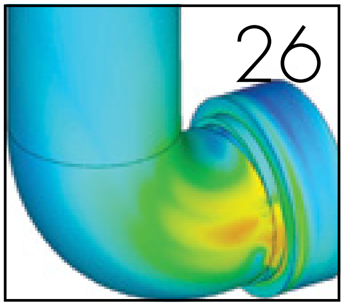
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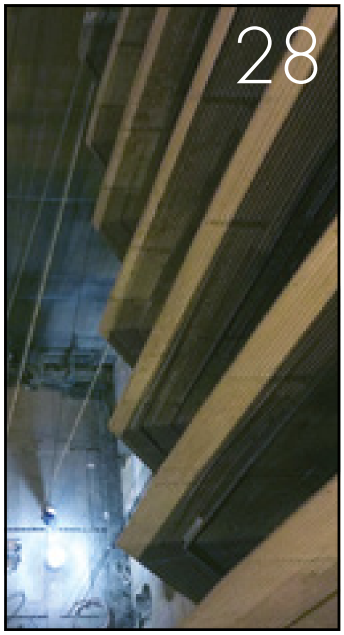
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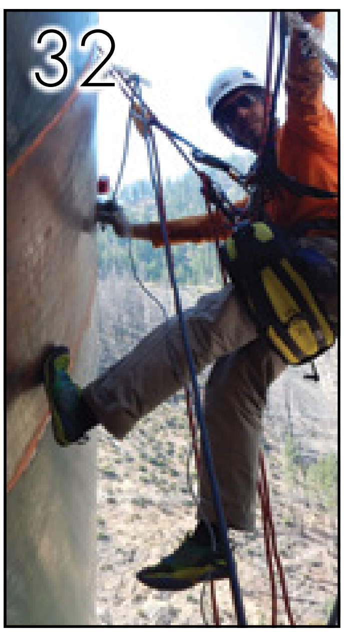
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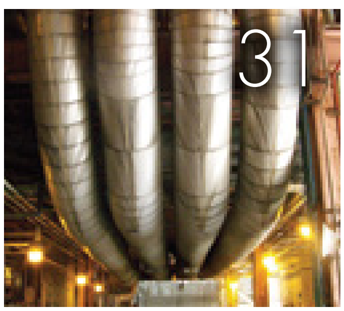
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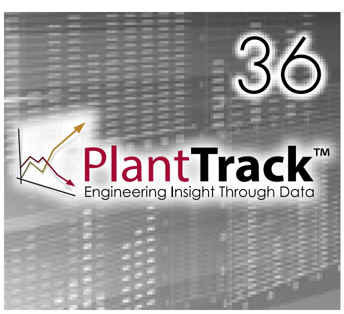
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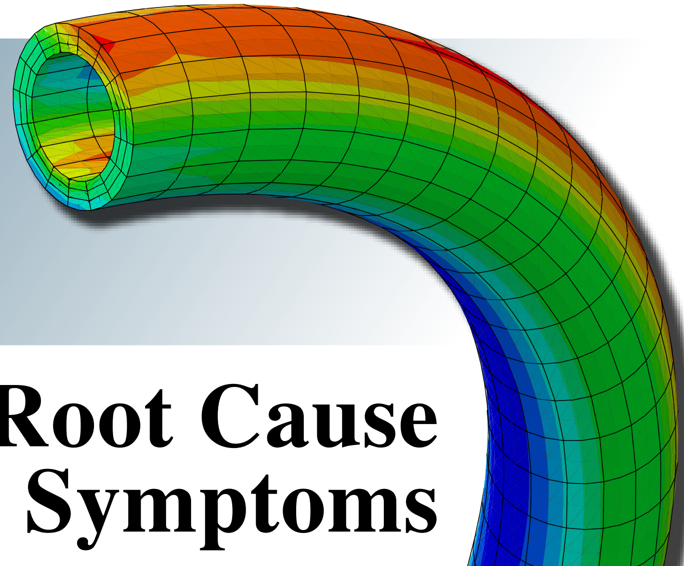
AC MITIGATION MISCONCEPTIONS

Prevention and mitigation of known threats for a pipeline operator is not only a best practice, but also a requirement when it comes to Pipeline Integrity Management. Engineering assessments such as External Corrosion Direct Assessment (ECDA), Stress Corrosion Cracking Direct Assessment (SCCDA), and In Line Inspection (ILI) are utilized to identify threats to pipeline integrity where active damage is likely to occur. Using tools such as Direct Current Voltage Gradient (DCVG) and Close Interval Surveys (CIS) aids in locating damage which has either occurred to the pipeline or its corrosion prevention systems.

While these methods have been proven successful in the identification and mitigation of known threats, they often focus on the identification and correction of symptoms rather than the larger and more complex root cause. For example, ECDA activities may focus on the identification and remediation of external corrosion and coating holidays. While this prevents future damage, it does not address the root cause of why the corrosion will occur when a coating holiday is present, such as adjacent buried structures, soil composition, induced Alternating Current (AC), etc.

Addressing the root cause of pipeline damage at coating holidays requires an understanding of why the pipeline corrodes. Most steel pipelines will



Addressing the Root Cause Instead of the Symptoms

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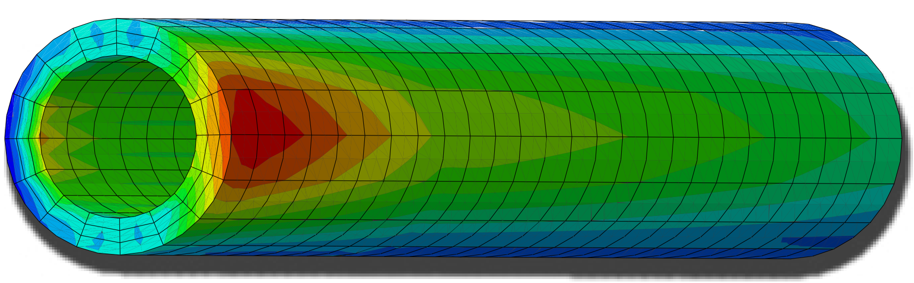
corrode when the right combination of factors to create a corrosion cell is present. The four required factors for a corrosion cell to develop are 1) cathode, 2) anode, 3) metallic path, and 4) electrolyte. Coatings are designed to limit this process by isolating the cathode, anode and metallic path from the electrolyte (soil). When coatings fail, the potential for electrochemical cell formation arises. Because of this known threat, Cathodic Protection (CP) is applied as a secondary means of corrosion control to prevent external corrosion at coating holidays.

Assessments and surveys may also be able to identify when AC interference is occurring along a pipeline. However, these assessments and surveys are only designed to identify the symptoms of AC interference, rather than the root cause. Unfortunately, all too often when dealing with AC interference, identified symptoms are used to determine the need for mitigation required and provide little insight into the appropriate location(s), quantity, and type of mitigation for an appropriately designed system.

Installing mitigation systems in areas where observed AC interference or corrosion has occurred can provide some level of protection to the pipeline. However, making decisions on mitigation strategies based solely on these symptoms can indeed cause the problem to get worse under certain conditions. This is because misplaced mitigation systems may simply shift the degradation threat to another unpredictable and unknown location along the pipeline. The reasoning behind this is fairly basic: AC corrosion is an undesired symptom, not the root cause of AC interference associated with pipelines.

The true root cause of AC interference for pipelines is the interactions of the pipeline with adjacent high voltage AC powerlines. This interaction occurs through a combination of capacitive, inductive, and resistance coupling. Capacitive, inductive, or resistance coupling occur where AC energy has accumulated on the pipeline. As this energy builds up, it seeks the path of least resistance to remote earth. Depending on the level of accumulated energy and coating conditions, the location at which the built up energy leaves the pipeline can produce accelerated corrosion rates. Without a properly designed mitigation system this discharge will occur at unpredictable locations along the pipeline. Often times this unpredictable discharge occurs near areas with coating holidays, low resistivity, or points of pipeline inflection. AC interference modeling is a key step in the development of an effective mitigation system. Through the modeling process, an understanding is developed of the true cause of AC interference, where energy is accumulating on the pipeline. With this understanding, a mitigation system can be designed to provide a safe discharge path near the point of energy accumulation.

Modeling also provides the opportunity to develop a mitigation system which is not only safe, but provides the most economical solution. This is due to the ability to model the remaining AC energy following the introduction of an AC mitigation system and throughout the modeling process, mitigation can be added, removed, or relocated within the model to reduce AC energy below specific acceptance criteria. In the end, this can allow operators to complete a cost benefit and risk analysis for reducing AC current densities below 20 a/m^2 versus 30 a/m^2 or evaluate the construction costs for a series of proposed pipeline routes.



CORE SHROUD WELD LOADS DEVELOPMENT

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In 2007, when Brunswick Steam Electric Plant (BSEP) changed GE fuel to AREVA ATRIUM-10 fuel, Structural Integrity Associates was contracted to perform a seismic re-analysis of the Reactor Pressure Vessel (RPV) and internals to determine the impact of the new fuel design on the Operating Basis Earthquake (OBE) and Design Basis Earthquake (DBE) loadings. The revised seismic loads from the 2007 analysis became the design basis loads for our evaluations of the core shroud. The BSEP core shroud configuration is shown in Figure 1.

In 2013, EPRI published BWRVIP-276 ("BWR Vessel and Internals Project, Evaluation to Justify Core Plate Bolt Inspection Elimination"), which provides guidelines to justify the elimination of core plate hold-down bolt inspections. A review of the computed horizontal seismic force at the core plate showed that the force from the 2007 analysis is higher than the corresponding load for Category 6 plants, which include BSEP. The higher core plate force put BSEP as a potential outlier with respect to the applicability of BWRVIP-276 in regards to core plate hold-down bolt inspections. It was, therefore, proposed that re-analysis of the BSEP RPV and internals be performed by removing any inherent conservatisms in the previous analyses. In the re-analysis, in addition to the core plate horizontal forces, the core shroud horizontal seismic loads at weld locations along the shroud height are also computed and compared to the corresponding design basis loads. For our discussion here, only the core shroud weld forces and moments are of interest and, as such, we are presenting the results on this topic only.

The key steps taken in our re-analysis include the following:

- The original GE STARDYNE seismic model is translated for re-analysis using the ANSYS software package. The finite element model is the same as that used in the original STARDYNE analysis, consisting of lumped mass stick models, representing the building enclosure, the RPV, the containment structure, the shield wall, the core shroud, the CRD housings, and the fuel. Mass elements are used to represent nodal translational masses and rotational inertias (where appropriate). Beam elements are used to represent structural components connecting the masses. Support stiffness in translational and rotational directions are modeled by spring elements at the support locations.

- Modal analyses of the translated model are performed, and the frequencies of the translated model are compared to the original frequencies of the STARDYNE model. The comparisons show that the fundamental frequencies for the STARDYNE and ANSYS models match closely, indicating that the STARDYNE seismic model has been successfully translated into the ANSYS model. The mode shapes and frequencies are later used in a transient dynamic analysis.

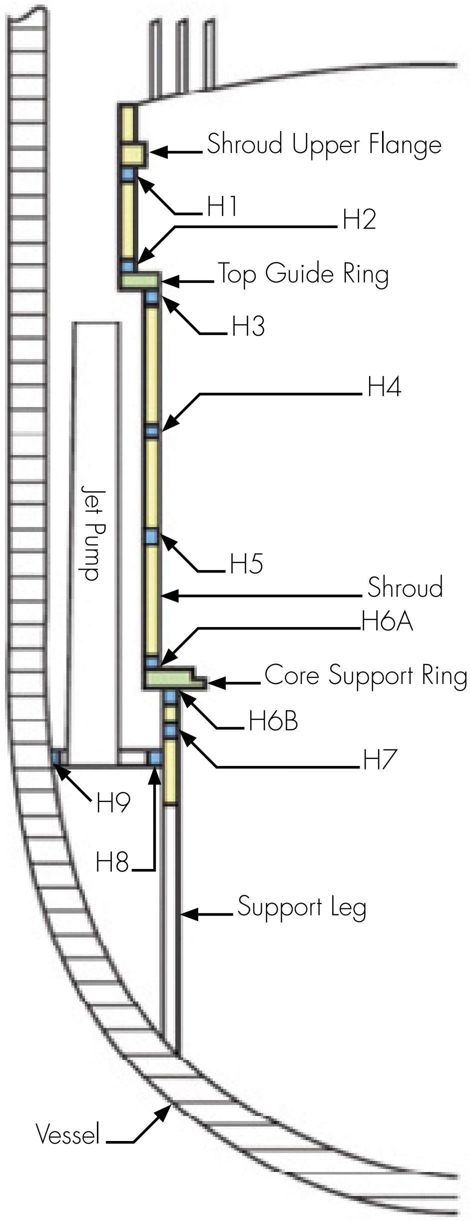

Figure 1. BSEP Core Shroud Configuration

- A transient dynamic analysis using the modal superposition approach is performed. The modal superposition method sums factored mode shapes (eigenvectors) from a modal analysis to calculate the structure's responses, with all modes up to 35 Hz included. This method accepts an effective modal damping ratio, which is expressed as a function of mode number. The calculation of the effective modal damping ratio uses material damping as input, and is computed from the ratio of the strain energy in each material in each mode. The input motion is an acceleration time history applied at the base of the structures in the two orthogonal horizontal directions. No vertical base motion is applied. The same acceleration time history is used in both horizontal directions. The time history is 25 seconds long, with a peak acceleration of 0.1g for the OBE case. The DBE is twice the OBE. Forces and moments at the core shroud welds are extracted for each of the horizontal directions. Final resultant forces due to the combined effect of the two seismic directions are determined by the square root of the sum of the squares (SRSS) method at each core shroud weld location.

- To capture the effect of the core plate-to-shroud stiffness on the horizontal forces, parametric analyses are performed for a range of core plate-to-shroud connection stiffness values. The bounding core shroud weld shear forces and moments from all the stiffness cases are conservatively used for comparison to the corresponding design basis forces and moments.

The notable differences between the 2007 design basis analysis and the re-analysis include:

- The design basis analyses used conservative damping values. The modal damping values for the DBE condition are conservatively set as 1.5 times the modal damping values for the OBE condition, and are generally lower than current recommendations. The re-analysis values are based on an effective modal damping for each mode determined from the material damping values obtained from the Updated FSAR for both OBE and DBE.

- The design basis analyses used a Guyan reduction procedure to compute the mode shapes. In this

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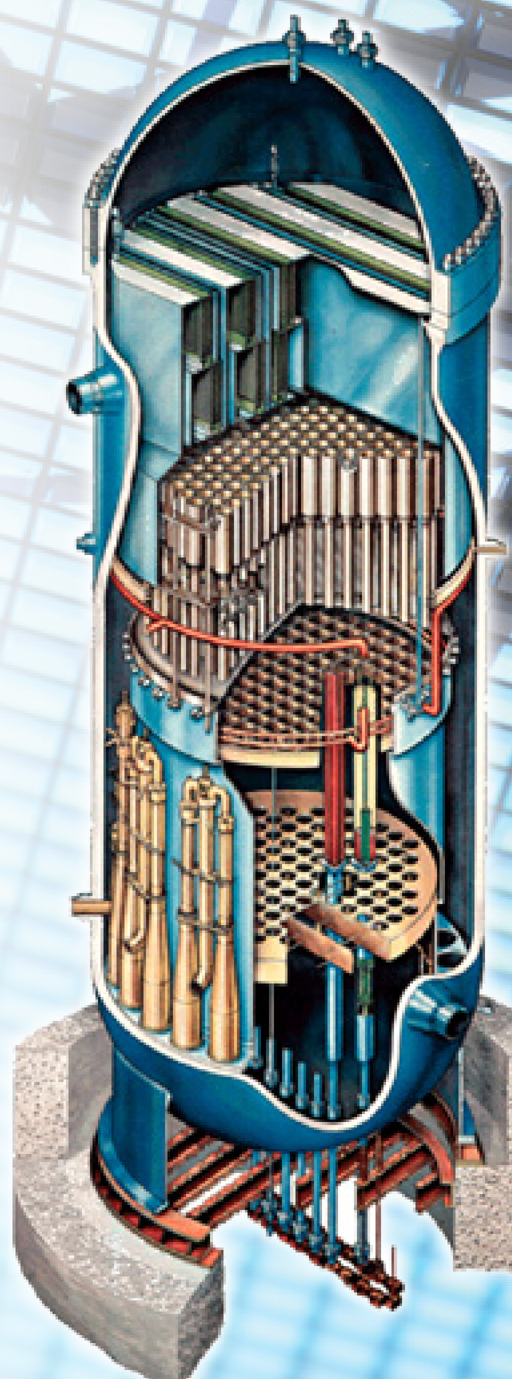

CORE SHROUD WELD LOADS DEVELOPMENT

CONTINUED

approach, the system of equations is first condensed down to those dynamic degrees-of-freedom (DOFs) associated with the master DOFs by Guyan reduction. This condensation procedure introduces approximations to the solution as a result of the reduction. The re-analysis uses an alternative solver, the PCG Lanczos solver, without the need for any condensed dynamic DOFs. Any approximation introduced by Guyan reduction is, therefore, eliminated in the current analyses.

- There are a total of 2,500 time steps in the input acceleration time history. The 2007 design basis analyses expanded to only 500 solutions for the total analysis duration, potentially missing higher peak forces between the 500-solution time steps. The re-analysis expands the solution to all 2,500 time steps for improved accuracy.

Comparisons of the core shroud weld forces and moments between the design basis and the re-analysis for both the OBE and DBE are summarized in Table 1 through Table 4.

Based on the comparisons, the core shroud weld shear forces and moments for the re-analysis are consistently lower than the corresponding values for the design basis analysis. Therefore, the core shroud weld shear forces and moments used in the design basis are conservative, and there is considerable margin in the design basis analysis and evaluations.

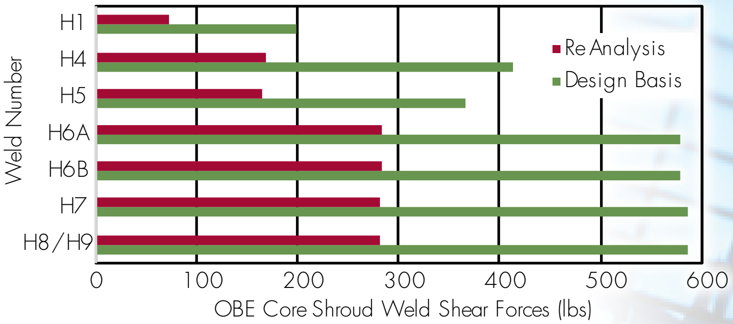

Table 1. Comparison of OBE Core Shroud Weld Shear Forces

Table 2. Comparison of DBE Core Shroud Weld Shear Forces

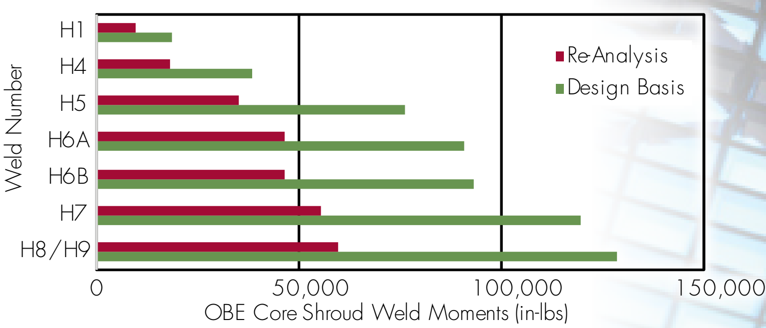

Table 3. Comparison of OBE Core Shroud Weld Moments

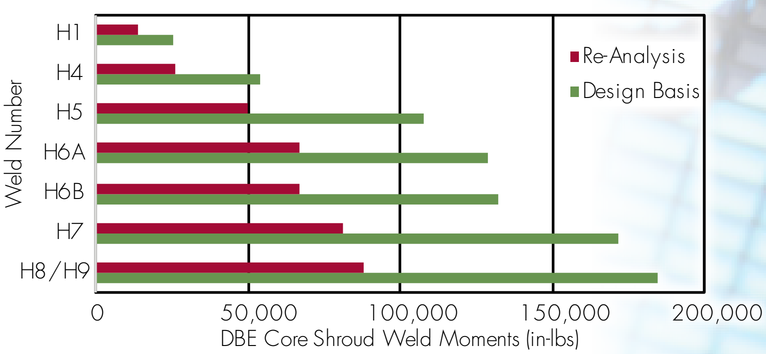

Table 4. Comparison of DBE Core Shroud Weld Moments

CYCLE CHEMISTRY KEY TO CORROSION CONTROL, PLANT RELIABILITY

By: BARRY DOOLEY
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The cycle chemistry treatments and control on fossil and combined cycle plants influence a high percentage of the availability, reliability and safety issues experienced on these plants worldwide.

This article – the first in our series -- describes chemistry treatments that can be used to help keep corrosion at bay in these plants.

This first article introduces the equipment and materials of construction and how reliability depends on various protective oxides, the formation of which relates directly to the cycle chemistry treatments that are used in the condensate, feedwater, boiler/evaporator water, and steam.

FOSSIL AND COMBINED CYCLE / HRSG PLANTS

Fossil and combined cycle/HRSG plants operate across a wide range of temperatures and pressures. Both once-through and drum boilers coupled to high pressure (HP), intermediate pressure (IP) and low pressure (LP) steam turbines are employed in traditional fossil-fired plants. Multi-pressure drum-type heat recovery steam generators (HRSGs) are normally used in combined cycle plants, but there are also a number of HRSGs with once-through HP or HP/IP circuits.

Mainly mild and low alloy steels are used in the construction of boilers and feedwater heaters, although copper alloys are also used for some condensers and feedwater heaters. High alloy steels and austenitic stainless materials are used in superheaters, reheaters and steam turbines. The protective and passive oxides that grow on the surfaces of this equipment and materials provide protection from corrosion.

The feedwater system is the major source of corrosion products, which can be transported into the fossil boiler or HRSG evaporator and deposited on the heat transfer surfaces of the water/steam cycle. Impurities in condensate, feedwater and cooling water increase corrosion, and corrosion products can also be generated by flow-accelerated corrosion (FAC).

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CYCLE CHEMISTRY KEY TO CORROSION CONTROL, PLANT RELIABILITY CONTINUED

Corrosion of copper alloys, if present in the feedwater heaters of fossil plants, can lead to the transport of copper into the boiler and deposits on the waterwalls, evaporators and the high pressure turbine. Some early combined cycle/HRSG plants also had feedwater heaters fed by extraction steam. The build-up of deposits in the steam generating tubes of the boiler or HP evaporators in HRSGs, in combination with the presence of impurities, can lead to under-deposit corrosion (UDC) during operation, and pitting in those sites during non-protected shutdowns.

The carryover of impurities into the steam can lead to deposits in the steam turbine, stress corrosion cracking in the superheaters and steam turbines, and pitting (particularly in reheaters) during non-protected or inadequate shutdown conditions.

Leaks in water-cooled condensers are a common source of impurities, such as chloride and sulfate, entering the water/steam circuit, whereas air-cooled condensers are subject to low temperature flow-accelerated corrosion and can be a source of high levels of corrosion products and air ingress.

One of the main purposes of good cycle chemistry is to provide protection through oxide formation on the internal steam/water touched surfaces and to prevent or reduce corrosion and deposits in the steam/water circuit of these power plants. A combination of chemical techniques is required to achieve this, and chemical conditioning can be applied to the condensate, feedwater and boiler water. Guidance limits have to be developed to control the corrosion processes. Failure to use optimal cycle chemistry and control will lead to major availability and reliability problems and can result in safety issues for plant staff.

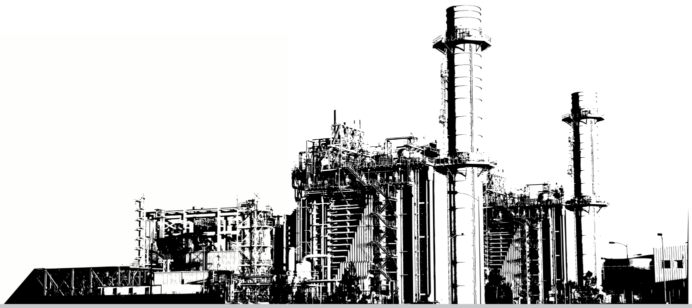
OPTIMUM CYCLE CHEMISTRY TREATMENTS

Optimum cycle chemistry requires owners to consider all the cycles of fossil and combined cycle plants. Most often, the cause of cycle chemistry influenced failure and damage mechanisms in a particular section or circuit does not originate at that location. For instance, feedwater corrosion products can be transported and deposited into the boiler/evaporator. Also contaminants in the boiler/evaporator originating in the condensate can be carried over into the steam turbine.

A quick "tour" of the chemistry for fossil and combined cycle plants follows. This overview provides an introduction of key features required for the cycle chemistry control of power plants. The first requirement is for high purity feedwater recycled from the condenser, or added as makeup. The purity is monitored by measuring the conductivity after cation exchange (CACE) (previously known as cation conductivity) of the condensate, feedwater, boiler and evaporator water, and steam. These measurements include contributions from impurities and corrosive species such as chloride, sulfate, carbon dioxide, and organic anions. The higher the temperature and pressure of operation, the higher the purity of water required to prevent corrosion and, thus, the lower the CACE allowed.

The chemistry of the condensate and feedwater is critical to the overall reliability of fossil and HRSG plants. Corrosion takes place in fossil plant feedwater systems (heaters, drains and interconnecting pipework) and in the feedwater of HRSG plants (preheaters and economizers) and the resulting corrosion products flow into the boiler or HRSG evaporators where they deposit on heat transfer areas. In the boiler/HRSG evaporator, these deposits can act as initiating centers for many tube failure mechanisms and as a source of efficiency losses or blade/disk failures in the steam turbine. The choice of feedwater chemistry depends primarily on the materials of construction and secondly on the feasibility of maintaining purity around the water/steam cycle.

Most often, a volatile alkalizing agent, usually ammonia, is added to the condensate/feedwater to increase the pH. Alternatively, a neutralizing amine or film forming product (FFP) can be added in lieu of ammonia. FFP include film forming amines (FFA) and film forming compounds which don't contain an amine.



❶ CONDENSATE AND FEEDWATER CYCLE CHEMISTRY TREATMENTS

Three main variations of volatile conditioning can be applied to the condensate and feedwater:

a **AVT(R) – All-volatile Treatment (Reducing)**
This treatment involves adding ammonia or an amine, FFP, blend of amines of lower volatility than ammonia and a reducing agent (usually hydrazine or one of the acceptable substitutes such as carbohydrazide) to the condensate or feedwater of the plant. In combination with a relatively low oxygen level (from air in-leakage) of about 10 ppb (µg/kg) or less in the condensate (usually measured at the condensate pump discharge, CPD), the resulting feedwater will have a reducing redox potential (usually measured as Oxidation-Reduction Potential, ORP). Higher levels of oxygen (>20 ppb (µg/kg), (due to high air in-leakage) will usually preclude generation of the reducing environment, but are often incorrectly accompanied by excessive dosing of the reducing agent. AVT(R) provides protection to copper-based alloys in mixed-metallurgy feedwater systems in fossil plants. Under optimum conditions, a fossil plant should be able to operate with feedwater corrosion products which are Fe < 2 ppb (µg/kg) and Cu < 2 ppb (µg/kg). Here the Fe and Cu values refer to the total concentrations of particulate metal oxides plus dissolved metal ions. In multi-pressure HRSG systems, AVT(R) should not be used in these cycles due to concerns for single-phase FAC and because the corrosion product levels in the feedwater would be most likely to exceed 2 ppb (µg/kg). Thus, a key basic international rule is that reducing agents should not be used in combined cycle / HRSG plants.

b **AVT(O) – All-volatile Treatment (Oxidizing)**
This all-volatile treatment has emerged as the treatment of choice for multi-pressure combined cycle/HRSG plants with no copper alloys in the feedwater. In these cases, a reducing agent should not be used during any operating or shutdown/layup period. Ammonia or an amine, FFP, blend of amines of lower volatility than ammonia is added at the CPD or condensate polisher outlet (CPO) (if a polisher is included within the cycle). In combined cycle/HRSG plants with relatively good control of air in-leakage (oxygen levels in the range 10–20 ppb (µg/kg)), the resulting feedwater will yield a mildly oxidizing ORP. Under optimum conditions, a fossil plant should be able to operate with corrosion product levels of total Fe < 2 ppb (µg/kg) in the feedwater; for multiple pressure combined cycle plants, the total Fe should be < 2 ppb (µg/kg) in the feedwater and < 5 ppb (µg/kg) in the drums.

c **OT – Oxygenated Treatment**
For conventional fossil plants, optimized OT involves one oxygen injection location at the CPO, operating with the vents on the feedwater heaters and deaerator closed, and with knowledge of the total iron levels at the economizer inlet and in the feedwater heater cascading drain lines. Ammonia is added at the condensate polisher outlet. Often, a minimum level of oxygen is required to provide full passivation of the single-phase flow locations in the main feedwater line and the drain lines, and to maintain this protection. For drum units this is usually between 30 and 50 ppb (µg/kg) at the economizer inlet (with the actual level being set in accord with the boiler recirculation ratio), and for once-through/supercritical units this is usually 30–150 ppb (µg/kg) at the economizer inlet. Application of OT in combined cycle/HRSG plants is much rarer; in these plants, it is often found that the use of AVT(O) with low levels of oxygen (< 10 ppb (µg/kg), does not provide sufficient oxidizing power to passivate the very large internal surface areas associated with preheaters, LP, IP and HP economizers, and LP evaporators, especially if a deaerator is included in the LP circuit. In these cases, oxygen can be added at the same level as for conventional recirculating cycles. This is the treatment of choice for fossil units with all-ferrous feedwater heaters, a condensate polisher, and the ability to maintain a CACE of < 0.15 µS/cm under all operating conditions. Under optimum conditions, a fossil plant should be able to operate with corrosion product levels of total Fe < 1 ppb (µg/kg) in the feedwater; for multiple pressure combined cycle plants the total Fe should be < 1 ppb (µg/kg) in the feedwater and < 5 ppb (µg/kg) in the drums.

FFP – Film Forming Products

The application and use of FFP in fossil and combined cycle/HRSG plants is increasing worldwide. Unlike conventional treatments, FFP are adsorbed onto metal oxide/deposit surfaces, providing a physical barrier (hydrophobic film) between the water/steam and the surface. Three main chemical substances have been used historically: Octadecylamine (ODA), Oleylamine (OLA) and Olyeylpropylendiamine (OLDA). Along with these compounds, the commercial products also contain other substances such as: alkalizing amines, emulsifiers, reducing agents, and dispersants. There is currently much confusion about their application for both normal operation and shutdown/layup, and there is no international guidance on deciding whether to use an FFP and whether it will provide a benefit to the plant.

Continued on next page

CYCLE CHEMISTRY KEY TO CORROSION CONTROL, PLANT RELIABILITY CONTINUED

Some basic international rules are in place for the application of these condensate/feedwater treatments. The all-volatile treatments – AVT(R), AVT(O), or OT – must be used for once-through boilers without any further addition of chemicals in the boiler or HRSG evaporators. AVT(R), AVT(O) or OT can also be used for drum boilers of fossil plants or combined cycle/HRSGs without any further addition of chemicals to the boiler/HRSG drum. However, impurities can accumulate in the boiler water of drum-type boilers and it is necessary to impose restrictive limits on these contaminants as a function of drum pressure, both to protect the boiler from corrosion and to limit the amount of impurities possibly carried over into the steam, which could put the superheaters, reheaters, and steam turbines at risk. AVT has essentially no capability to neutralize or buffer feedwater/boiler water dissolved solids contamination. Ammonia is a rather poor alkalizing agent at high temperatures, offering very limited protection against corrosive impurities.

❷ Fossil Boiler Water and HRSG Evaporator Cycle Chemistry Treatments

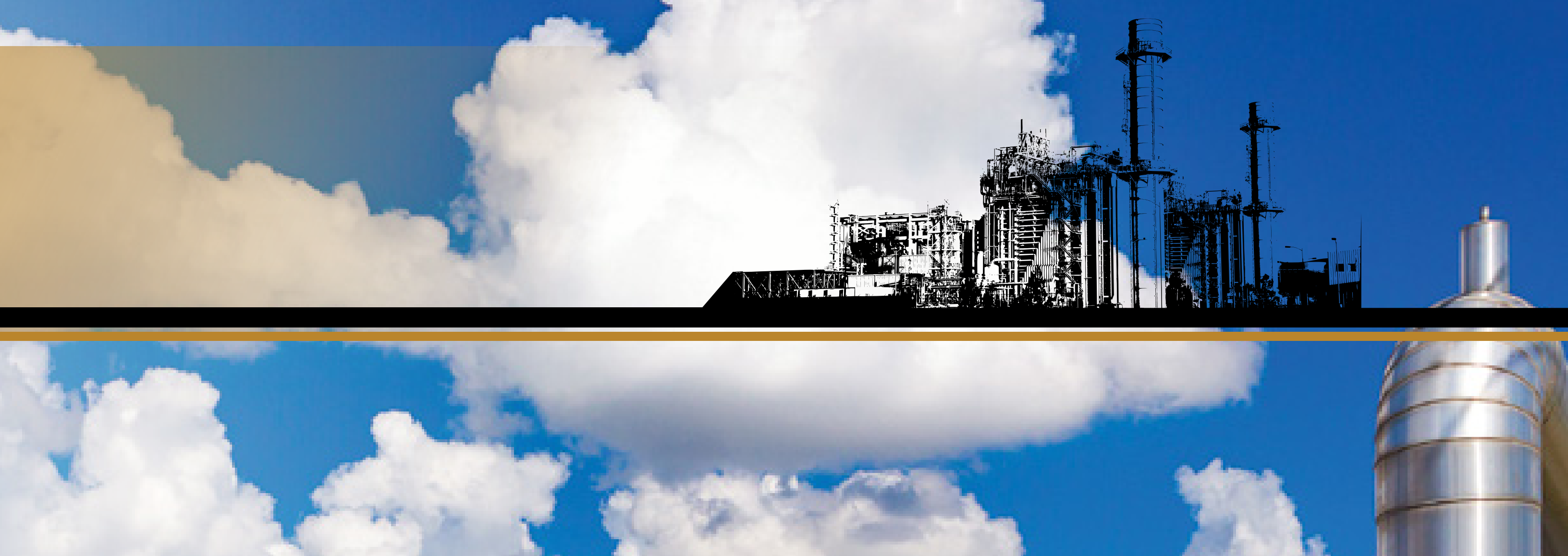
For some drum-type boilers, the addition of solid alkalizing agents to the boiler/HRSG water may be necessary in order to improve the tolerance to impurities and reduce the risk of corrosion. The alkalizing agents which can be used for this are tri-sodium phosphate [phosphate treatment (PT)] or sodium hydroxide [caustic treatment (CT)] used alone, or in combination. The amounts of sodium hydroxide added have to be strictly limited to avoid excessively alkaline conditions, which can result in a UDC mechanism (caustic gouging), which destroys the protective oxide layer in the boiler or HRSG evaporator. The amounts of both sodium hydroxide and tri-sodium phosphate added to the cycle also have to be controlled to avoid an increase of carryover of these conditioning chemicals into the steam, possibly putting the superheaters and turbines at risk.

Boiler and HRSG evaporator treatments are critical to the overall reliability of fossil and HRSG plants as they control and influence not only the major tube failure mechanisms but also a number of damage mechanisms in the steam turbine.

- **PT – Phosphate Treatment**
  Phosphates of various types have been the bases of the most common boiler/HRSG evaporator treatments worldwide. However, historically a multitude of phosphate compounds and mixtures blended with other treatment philosophies have resulted in a wide range of control limits for the key parameters (pH, phosphate level, and sodium-to-phosphate molar ratio) and a number of reliability issues. Some of the traditional phosphate treatments such as congruent phosphate treatment (CPT), coordinated phosphate treatment, and equilibrium phosphate treatment (EPT) have been used over the last 50 years across the fleet of fossil boilers and HRSG evaporators, sometimes successfully, sometimes resulting in tube failures and other problems. For instance, the use of CPT, where mono- and/or di-sodium phosphate are used to develop operating control ranges below sodium-to-phosphate molar ratios of 2.6:1, has resulted in serious acid phosphate corrosion (APC) in many boiler waterwalls and HRSG HP evaporators which have heavy deposits and have experienced phosphate hideout.

More recently, 20 years of collective global operating experiences have shown that tri-sodium phosphate (TSP) should be the only phosphate chemical added to a boiler/HRSG and that the operating range should be bounded by sodium-to-phosphate molar ratios of 3:1 and TSP + 1 ppm (mg/kg) NaOH with a pH above 9.0 and a minimum phosphate limit above 0.3 ppm (mg/kg). The 0.3 ppm (mg/kg) level is considered a minimum; better protection is afforded by operating at the maximum level of phosphate possible without experiencing hideout or exceeding the steam sodium limits.

PT can be used in a wide range of drum units, up to high pressures (19 MPa, 2800 psi), so it is often the only alkali treatment available because CT is not suggested to be used above 16.5 MPa (2400 psi). However,



hideout and hideout return become more prevalent with increasing pressure. Hideout and hideout return are always associated with large swings of pH causing control problems, but if only TSP is used, then no harmful corrosion reactions can be initiated as was experienced with CPT using sodium-to-phosphate molar ratios below 2.6:1.

For multi-pressure HRSGs, PT can also be used in each of the pressure cycles; however, use of PT in these cases is for different reasons depending on the pressure of the circuit. At high pressure (HP drums >10.3 MPa (1500 psi)), TSP is added to address contamination as it is for conventional fossil plants. In the lower pressure circuits, with temperatures below 250 °C, PT is used to help control two-phase FAC much as CT is used in these circuits. Of course neither solid alkali is used in the LP evaporator in units where the LP drum feeds the IP and HP feedpumps and attemperation.

- **CT – Caustic Treatment**
  Caustic treatment (CT) can be used in "conventional" fossil and HRSG drum-type boilers to reduce the risk of under-deposit corrosion and in HRSGs for controlling flow-accelerated corrosion, where all-volatile treatment has proved ineffective, or where PT has been unsatisfactory due to hideout or has experienced difficulties of monitoring and control.

The addition of sodium hydroxide to the boiler/evaporator water has to be carefully controlled to reduce the risk of caustic gouging in the boiler and carryover into the steam, which could lead to damage of steam circuits and turbine due to stress corrosion cracking. Of primary risk are austenitic materials, stellite, and all steels with residual stresses (e.g., welds without heat treatment) in superheaters, steam piping and headers, turbine control and check valves, as well as components in the steam turbine. CT is easy to monitor, and the absence of the complications due to the presence of phosphate allows on-line conductivity and CACE measurements to be used for control purposes.

SUMMARY

This high-level overview of optimum cycle chemistry treatments for fossil and combined cycle/HRSG plants is the starting point of our discussion. Future issues of News & Views will describe cycle chemistry failure/damage mechanisms and how they are typically dealt with retroactively. We will also explore how SI's advanced analytical tools can help plant owners identify the risk and root cause of cycle chemistry-related damage and failure.

There are a plethora of international guidelines and guidance available in many countries of the world for the reader: IAPWS (International), EPRI (US), VGB (Germany), JIS (Japan), Russian, Chinese, Manufacturers of major fossil and combined cycle/HRSG equipment (International), Chemical Supply Companies (International). Structural Integrity Associates uses the Technical Guidance Documents (TGD) of the International Association for the Properties of Water and Steam (IAPWS) in all the cycle chemistry related plant assessments and root cause analyses conducted. These are freely downloadable on the IAPWS website (www.IAPWS.org).

FLOW DISTRIBUTORS ENSURE A UNIFORM PRECOAT ON FILTER DEMINERALIZERS

finetech

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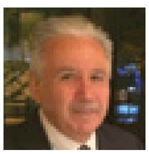

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Filter demineralizers (F/Ds) perform the dual function of ion exchange and filtration to remove ionic and particulate impurities from water. These systems are used extensively in BWRs for condensate polishing, reactor water cleanup, fuel pool cleanup and liquid radwaste processing. Upright cylindrical vessels contain numerous backwashable filter septa (also called elements), typically constructed of porous polypropylene media or stainless steel mesh layers. The F/D vessel is prepared for service by circulating flow around the precoat loop in the normal service direction (from the septa OD to the ID) and metering precoat material containing powdered ion exchange resin into the inlet flow stream. After the precoat is deposited on the ODs of the septa, the vessel is placed in service until a run termination criterion is met; either effluent chemistry, differential pressure or time. When the service run is complete, the spent precoat layer is removed by an air-water backwash in preparation for the next precoat. In the BWR, spent precoat material contains radioactive ionic and particulate impurities removed from the process stream and must be disposed of as radioactive waste.

Each septum is connected to the F/D vessel tubesheet, which separates the untreated water from the treated water. Vessels from different manufacturers use either a top or bottom tubesheet design. A partial view of the bottom tubesheet design is depicted in Figure 1. The inlet flow enters from the bottom center and impinges on a baffle plate, which diverts the flow radially outward toward the vessel wall.

In the 1970s, in response to short run times to ionic impurities breakthrough or a differential pressure endpoint due to particulate crud accumulation, Organo Corporation, a leading water treatment company with headquarters in Tokyo, Japan, conducted a test program on a full-size mock-up vessel instrumented to measure liquid velocities during the precoat and service conditions. Organo found that the flow pattern in the conventional vessel resulted in velocities that were too high near the bottom of the septa, causing precoat material to shear off the septa, and so low at the top that the precoat was too thin. It was well known that a uniform precoat and uniform flow distribution are needed to maximize F/D performance. This led Organo to develop the Integrated Flow Distributor (IFD) design to improve the vessel internal flow distribution.

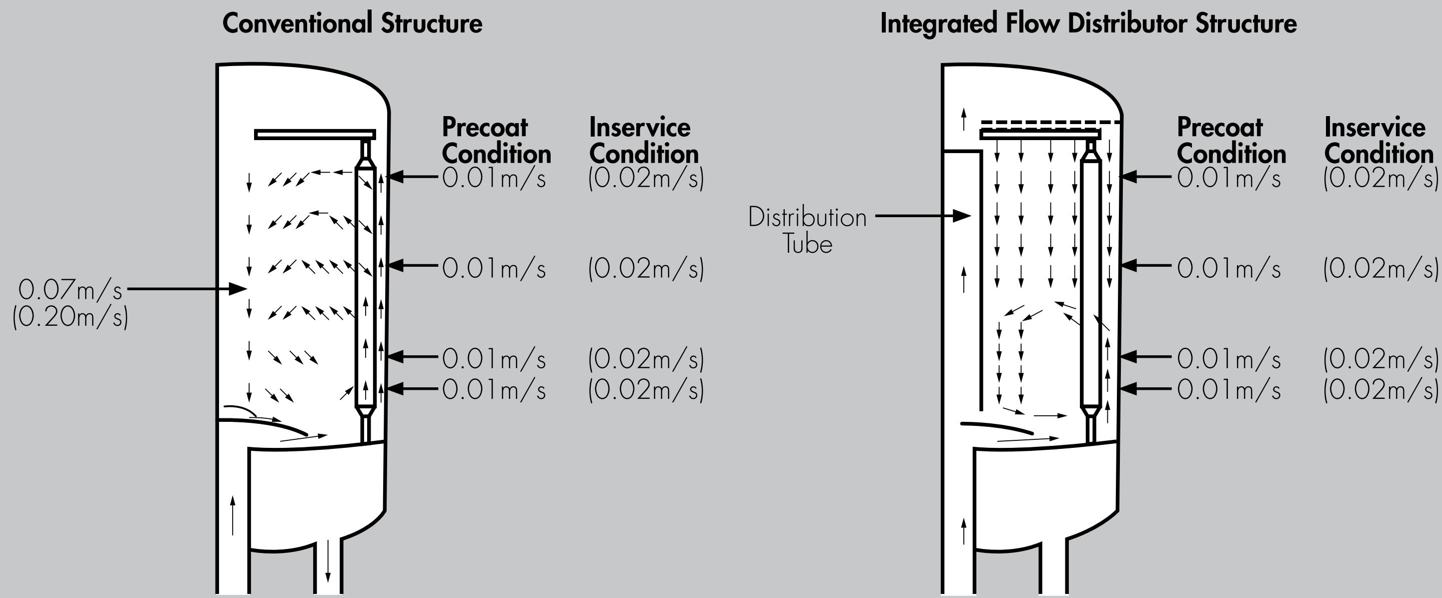

Figure 1. Bottom Tubesheet F/D Flow Distribution Improvement with IFD

The conventional (original) design bottom tubesheet vessel, and the same vessel with a custom designed IFD installed, is shown in Figure 2. The IFD retrofit is comprised on a new baffle plate to which a center distribution tube is fixed, and flow distribution and straightening components at the top of the vessel. F/D vessel designs vary in diameter from 24-inches to 78-inches, and vary widely in flow rates. There are also several different vessel top head configurations. These differences in geometry and flow result in the need to customize the IFD design for each vessel.

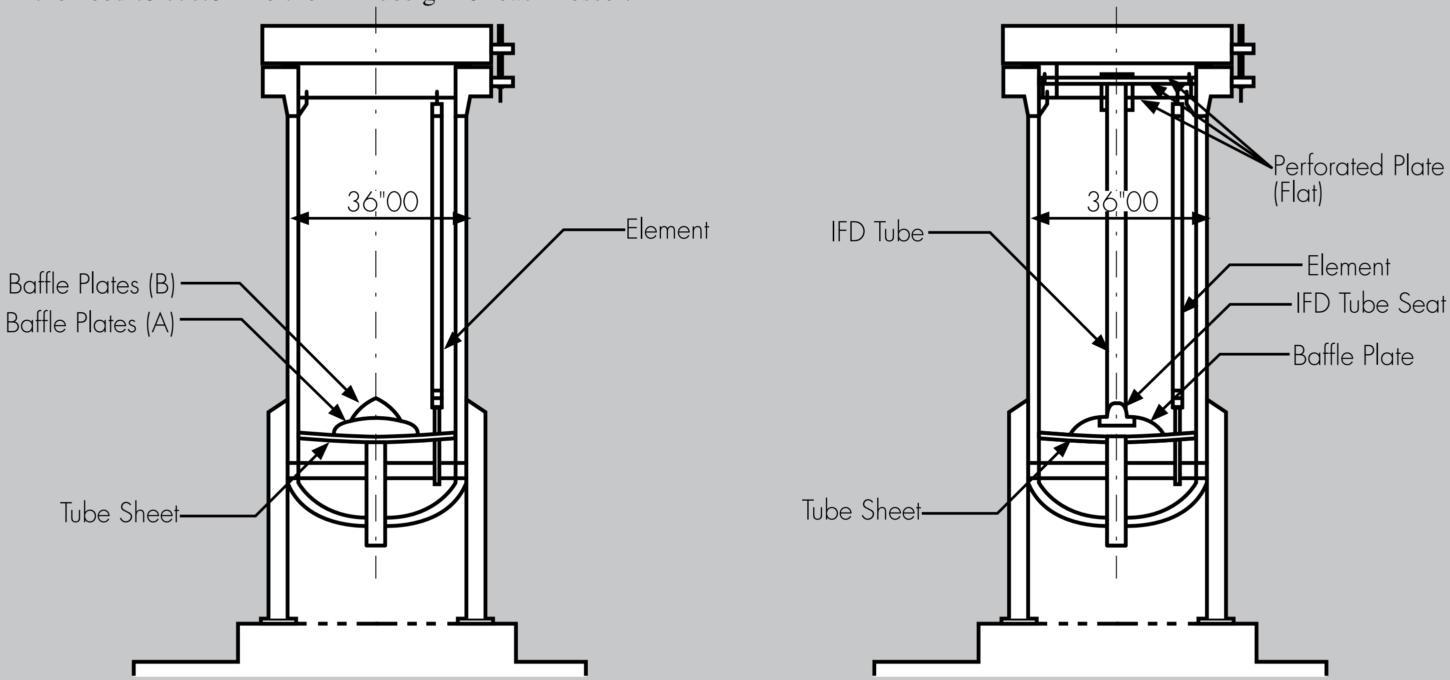

Figure 2. Conventional Vessel and Vessel with IFD Installed

FLOW DISTRIBUTORS ENSURE A UNIFORM PRECOAT ON FILTER DEMINERALIZERS

CONTINUED

The IFD lowers the fluid velocity at the bottom of the vessel by control of the fraction of the flow that exits radially from the baffle plate opening and that which goes up to the top via the IFD tube. The flow distribution and straightening components at the top are custom designed to provide the proper flow conditions to convey and uniformly deposit precoat material at the tops of the septa. Splitting the incoming flow between the IFD tube and the bottom baffle plate, along with the improved flow pattern at the top, results in more uniform flow patterns in service and during precoating, resulting in improved performance. Organo applies a computational fluid dynamics model for each IFD installation. Examples of the velocity (m/sec) profiles at the vessel bottom and top are shown in Figure 3 and Figure 4, respectively.

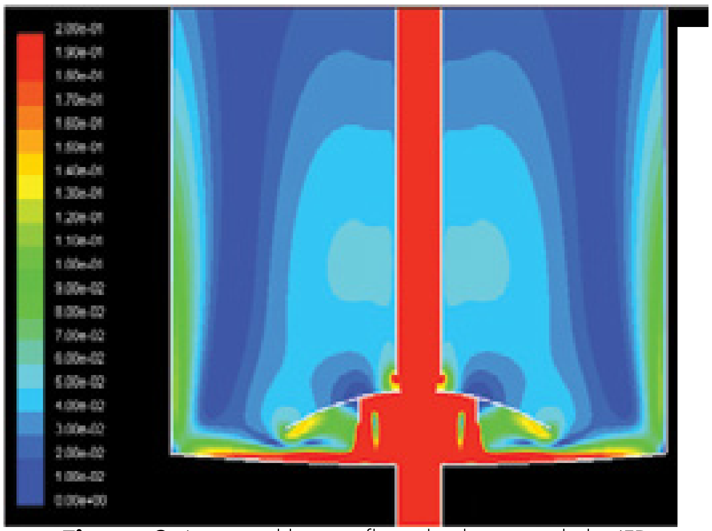

Figure 3. Improved bottom flow distribution with the IFD

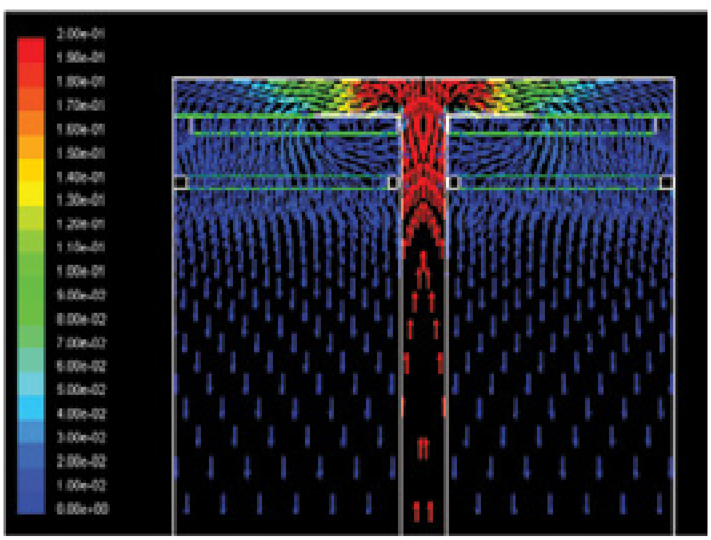

Figure 4. Improved top flow distribution with the IFD

Organo successfully retrofitted IFDs in approximately 100 bottom tubesheet F/D vessels in Japanese BWR plants. Condensate F/D vessels in Japan employed yarn wound septa and, in all cases, run lengths to a differential pressure endpoint increased by 1.5 – 2 times after IFD installation. When reactor water cleanup (RWCU) flow was increased by a factor of 2 in Japan, and the conventional RWCU F/D area flow increased from 1 gpm/ft^2 to 2 gpm/ft^2, the DF (decontamination factor = inlet concentration/outlet concentration) for cobalt-58 declined dramatically, as shown in Figure 5. After the IFD was installed, the DF at 2 gpm/ft^2 was more than a factor of 2 better than the conventional vessel at 1 gpm/ft^2, demonstrating the benefit of improved flow distribution in the same vessel at higher total flow.

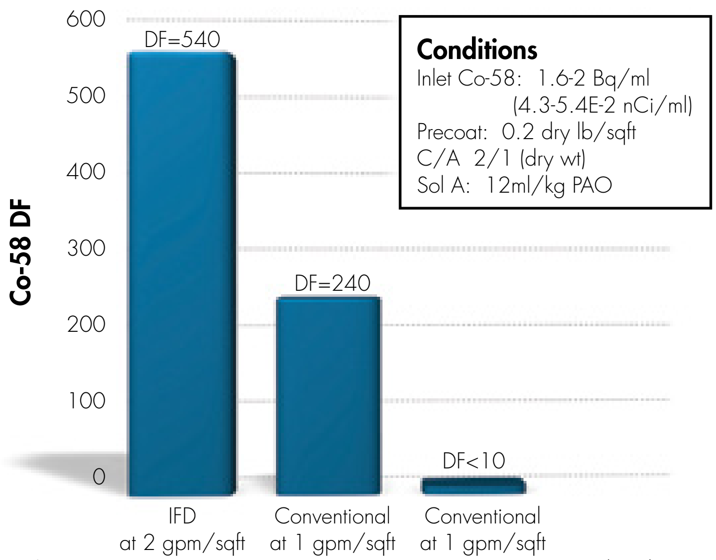

Figure 5. Co-58 Decontamination Factor (DF) Improved with IFD

Our Finetech founders' technical relationship with Organo dates back to the 1960s, and technology exchange continued after Finetech was formed in 1983. In 2007, Finetech entered into an exclusive licensing agreement with Organo to extend the IFD technology to existing bottom tubesheet F/D vessels. Since then, Organo and Finetech have collaborated on IFD retrofits in the U.S., Europe and Mexico. The licensing agreement has been renewed following the acquisition of Finetech by Structural Integrity in 2015.

Organo-Finetech IFD projects have resulted in similar performance improvements as experienced in Japan. Side-by-side comparison results in condensate F/D service for a conventional vessel and the first U.S. vessel with IFD, starting with new septa in each vessel, are plotted in Figure 6 and showed two times the run length with IFD after 9 months of service. The first U.S. RWCU F/D with

IFD demonstrated significantly improved removal efficiencies for activated corrosion products, including cobalt-58 and cobalt-60, as shown in Figure 7.

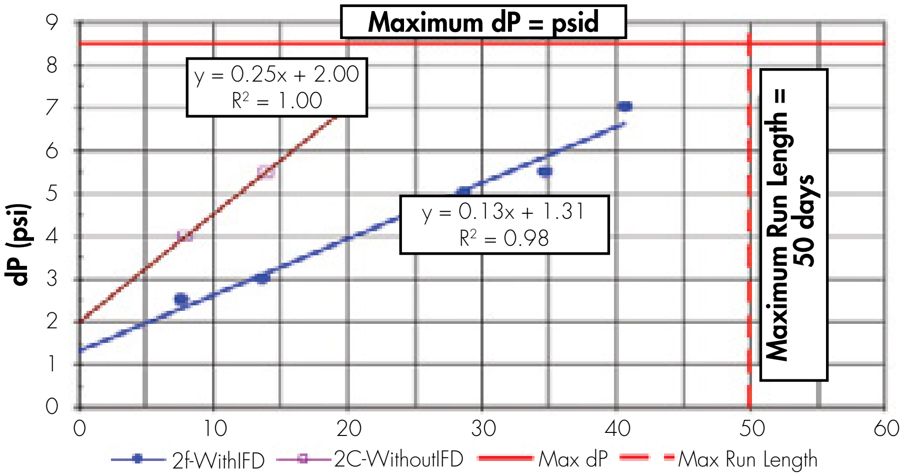

Figure 6. Twice the Run Time with IFD after 9 months of service

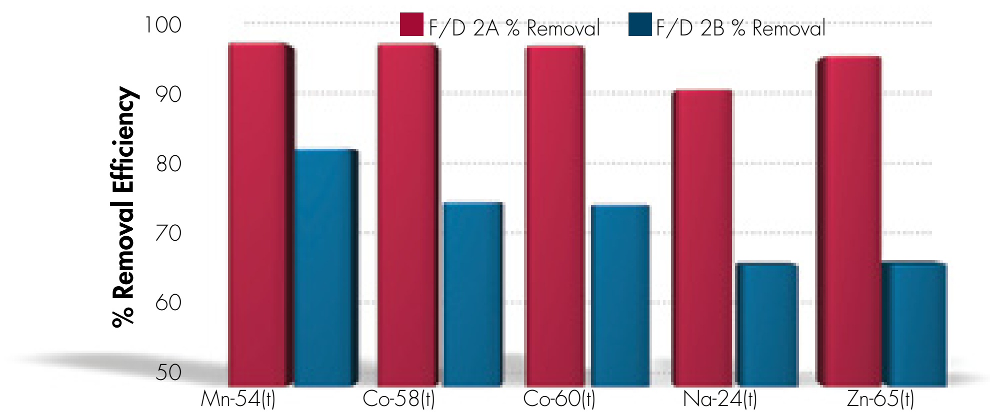

Figure 7. Improved Removal Efficiency of Activated Corrosion Products with IFD at 45 days Run Time (t = total, filterable and non-filterable), F/D 2A with IFD, F/D 2B without IFD

Since 2007, we have collaborated with Organo on the design, supply and implementation of 68 IFDs for BWR condensate and reactor water cleanup F/D vessels. The application of sophisticated computer modeling and attention to detail have resulted in improved performance in all cases. The innovative IFD is mechanically fastened within the F/D vessel, so installation requires no welding. Finetech provides on-site engineering support during installation. Additional IFD installations are being planned as part of extended power uprates or system upgrades to improve water chemistry and reduce radioactive waste volumes. In addition to BWR condensate and reactor water cleanup applications, fuel pool F/Ds are among future candidates for IFD upgrades. During refueling outages, fuel pool F/Ds are relied on when the reactor water cleanup system is out of service for required maintenance to achieve high removal efficiencies of activated corrosion products to minimize refuel floor and work platform radiation levels and contamination of wetted surfaces.

GARY STEVENS REJOINS OUR NUCLEAR TEAM

By: GARY STEVENS

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Many things in life come full circle and my return to Structural Integrity Associates is one of them. I am pleased to say that I have rejoined Structural Integrity as a Senior Associate effective January 25th and will be responsible for helping their efforts in the nuclear market where my expertise and technical/regulatory background will be of assistance to fellow employees and clients. In addition to my previous work at Structural Integrity from 1995-2010, my other work experience includes the U.S. Nuclear Regulatory Commission (2010-2015) and GE Nuclear Energy (1981-1995).

This experience will help me develop our participation with ASME/EPRI efforts associated with aging management of spent fuel storage canisters, and with deployment of load monitoring to the next generation of deep water high pressure, high temperature (HPHT) oil and gas applications.

Though I am temporarily working out of my house in Maryland, I plan to relocate to our Huntersville (Charlotte), NC office in April. Feel free to contact me at gstevens@structint.com.

I welcome the opportunity to hear back from you or to answer your questions anytime!

Featured Damage Mechanism - Acid Phosphate Corrosion

By: WENDY WEISS
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Acid Phosphate Corrosion (APC) is one of the three major underdeposit corrosion (UDC) mechanisms that has been encountered in recent years at many fossil plant boilers as well as at combined cycle plants with heat recovery steam generators (HRSGs).

Figure 1. Pinhole leak on OD surface of waterwall tube

MECHANISM

APC requires the combination of heavy internal deposits with a concentration of phosphate when using mono-sodium or di-sodium phosphate water treatment. These chemical phosphate blends have sodium to phosphate ratios lower than 3:1. Thermal-hydraulic conditions such as steam blanketing or wick boiling lead to fluxing of the protective magnetite layer and in some cases the actual metal surface. Sodium phosphates exhibit retrograde solubility, which is a decrease of solubility with increasing temperature. This may also assist the local concentration.

Reaction products will include maricite ($NaFePO4$), which forms when magnetite reacts with mono- or di-sodium phosphate. Maricite is a key indicator of the acid phosphate corrosion mechanism. Once the local corrosive environment is formed, a local gouge on the internal surface is created. Final failure occurs when the reduced tube wall can no longer support the internal pressure. The macroscopic appearance is typically a ductile pinhole leak.

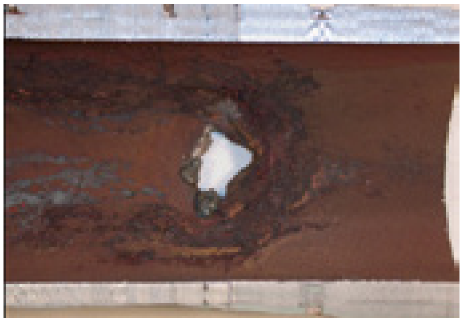


Figure 2. Gouging on ID surface of waterwall tube due to ACP

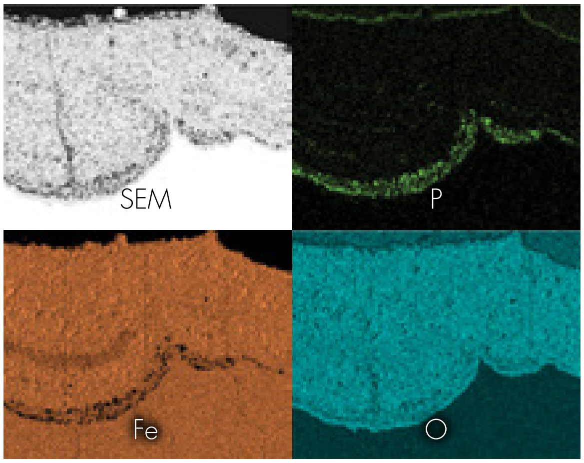
TYPICAL LOCATIONS

- Waterside mechanism
- Hot side of tubes
- Highest heat flux areas
- Near flow disruptors: Joints, Bends, etc.
- Improper welds

FEATURES OF FAILURE

- Pinhole leak or thin-edged failure
- Gouging on ID surface
- Thick loose deposits within gouge
- Phosphorus (maricite) detected at base of gouge
- No microstructural changes

Figure 3. SEM/EDS elemental mapping of deposits within a pitted/gouged area in a waterwall tube. Phosphorus is concentrated beneath the deposits



Case Study-Welding Flaw Contributes to Creep Failure of a Type 321 Tube

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Figure 1. Tube shown in as-received condition

We recently inspected an interesting case of a cracked weld in a Type 321 stainless steel superheater tube illustrating how several variables can contribute to a failure. The tube had been in service for approximately 210,000 hours, but the weld was a repair that had been in service for about 120,000 hours. The weld was made in the field with the specified 347 AWS – A5.9/A5.14 ER347Si welding wire. The main steam temperature was reported to be 1005°F and the main steam pressure was reported to be 2600 psi.

The tube section is shown in the as-received condition in Figure 1. The crack extended around the circumference of the weld. The crack surfaces had a dull, light gray color indicative of heavy oxide buildup. An area with a shear lip, which is symptomatic of final overload, was also present. Apparent secondary cracks were observed on both the OD and ID surfaces.

METALLOGRAPHY

Three cross-sections were cut from the tube section. Sample A was cut through the area that contained the heavily oxidized crack surface and was in an area with washing damage. Samples B and C were cut on either side of Sample A in areas that exhibited the secondary cracks.

An overall view of the weld crack in Sample A is shown in Figure 2. The crack was relatively straight from the OD to the ID. The crack surfaces exhibited a relatively heavy scale/slag/oxide buildup. Interdendritic microcracks were present adjacent to the crack surfaces, and were mostly contained within the lower half of the weld. A relatively large slag inclusion was present along the crack surface, on the left side in Figure 2. Areas that exhibited a mixture of oxide buildup and slag were present on the right side of the crack as shown in Figure 2.

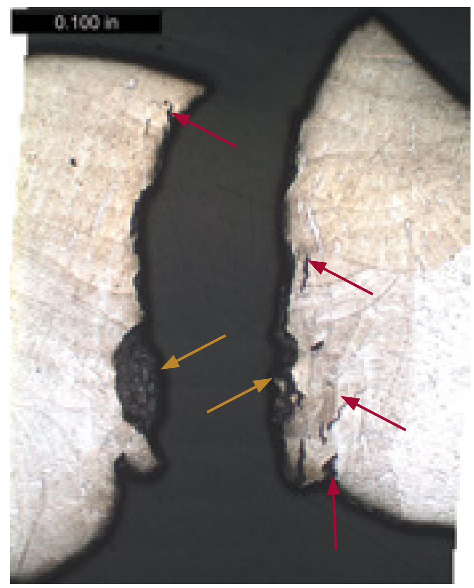

Figure 2. Cross-sectional view of Sample A. Creep damage (red arrows) was present along the fracture surface but more prevalent towards the internal surface (bottom of image). Areas of slag inclusions or a mixture of oxide and slag inclusions (yellow arrows) were present.

The Sample B crack (not pictured) was relatively straight from the OD to the ID. This sample contained creep damage throughout the weld, with a relatively large secondary crack present in the lower half of the weld. Other than the secondary crack, much of the damage within the weld metal was not connected to a tube surface. This sample did not have a thick oxide buildup along the crack surfaces; however, thin oxide was present intermittently along the crack surface.

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METALLURGICAL LAB CORNER
CONTINUED

The damage within the weld consisted of interdendritic microcracks and voids typical of creep damage in austenitic welds.

An overall view of Sample C is shown in Figure 3. The crack showed 45° shear lip from about the midwall towards the OD surface, and was relatively straight from about the midwall to the ID surface. The weld damage was contained within the lower half of the weld, and the damage was not connected to the ID surface. Similar to Sample B, this sample did not have any excessive oxide buildup along the crack surfaces. Figure 4 shows higher magnification views of the creep damage observed in this sample.

Figure 3. An overall view of Sample C. Notice that the most significant damage is contained within the lower half of the weld. The upper half of the crack is consistent with final overload.

The typical weld microstructure is shown in Figure 5. In general, the weld microstructures were as expected for an austenitic stainless steel weld. The presence of sigma phase in the weld material was confirmed by etching with potassium hydroxide, and was present consistently along the crack surfaces through the thickness of the weld.

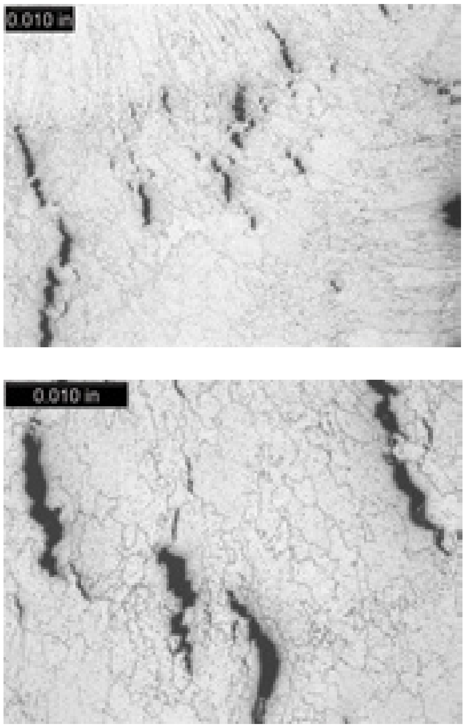

Figure 4. Higher magnification views of creep damage present in the weld in Sample C. (Etchant: Modified Currans)

SEM/EDS ANALYSIS

Figure 6 shows an SEM image of Sample A. Various areas of the weld and the base material of Sample A, including the welding slag on the crack surfaces and some areas of crack surface oxides, were analyzed using energy dispersive X-ray spectroscopy (EDS) to identify the elements present. Both the base and weld metal were consistent with their specifications. The large slag inclusion on both sides of the crack surface was primarily titanium and oxygen while the oxides were primarily iron and oxygen with lesser amounts of chromium and nickel.

DISCUSSION

Based on the presence of interdendritic microcracks and voids within the weld metal, the tube failure was caused by creep damage. The creep damage appears to have initiated midwall and propagated toward

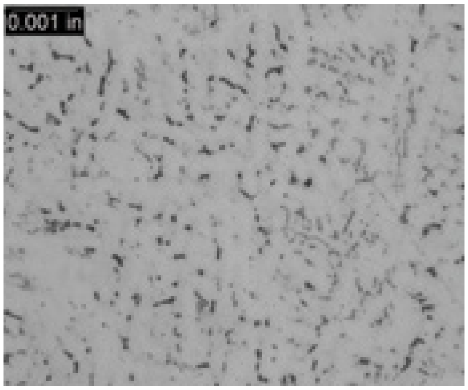

Figure 5. The typical weld metal microstructure shown with an electrolytic KOH etch which reveals the sigma phase throughout the weld microstructure.

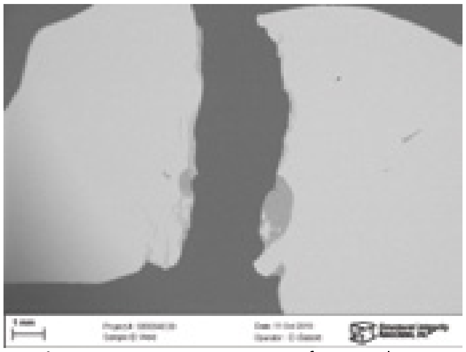

Figure 6. SEM image of Sample A.

the OD and ID surfaces. This observation is based on the presence of the majority of the damage within the weld metal not being connected to the surfaces.

Sample A was from the portion of the crack that exhibited the heaviest oxide buildup on the crack surfaces, suggesting that this area had been cracked the longest. The presence of the large slag inclusion in the oldest area of the crack suggests the welding flaw was a major factor in the initiation of the creep damage. A plausible failure scenario is that the region of the weld around the defect was at a higher stress, causing creep damage to form and propagate. As the crack became longer, the crack front broke through to the internal surface. Creep crack growth is significantly faster in a surface connected defect as compared to an embedded flaw. Thus, it is likely that through-wall growth resulted in a local through-wall crack. Continued defect growth occurred around the circumference of the weld until separation took place. It appears that the tube leak was present for some time before final fracture, although the laboratory evaluation did not allow quantification of the amount of time that the leak was present.

We confirmed sigma phase to be present in the weld metal. The formation of even a few volume fraction percentage points of sigma phase can reduce the stress rupture and corrosion resistance of the material. The formation of sigma phase was likely promoted by a relatively high level of ferrite in the original weld. Long term operation under superheater temperatures will cause the ferrite to transform to sigma phase. Its formation results in considerable embrittlement after cooling to ambient temperatures, and it can have a detrimental effect on material properties at higher temperatures as well. The presence of sigma phase in the weld would have increased its susceptibility to crack growth from the creep damage, and would also have increased the overall susceptibility to the formation of creep damage in the weld material.

ANATECH FOUNDER HONORED BY UC BERKELEY

Inductee Joe Rashid, right, accepts his citation from CEE Department Chair Robert Harley.

They numbered just ten, but their impact in the field of engineering has been felt worldwide.

This elite group – including our own Y.R. (“Joe”) Rashid, P.E., PhD – gathered at California Memorial Stadium on October 9, 2015, for their induction into the University of California, Berkeley’s Civil and Environmental Engineering (CEE) Department’s Academy of Distinguished Alumni.

The university established the Academy in 2012 to recognize alumni with outstanding professional achievements and service to society.

As the founder of ANATECH (today a subsidiary of Structural Integrity), Dr. Rashid pioneered leading edge modeling techniques that made the company the foremost authority in structural seismic performance. His contributions to the profession also include more than 200 technical papers and participation on expert panels for the U.S. Nuclear Regulatory Commission, U.S. Department of Energy and other organizations.

Structural Integrity Associates was proud to sponsor the Academy’s fourth annual banquet, which raised $30,000 for the CEE department’s prestigious Undergraduate Research Opportunity Program.

We congratulate our colleague and his fellow inductees on this much-deserved honor!

THE IMPORTANCE OF BALANCED CP CURRENT DISTRIBUTION IN PLANTS

By: ANDY SMART
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Suppose you are the plant engineer overseeing a new or replacement impressed current cathodic protection (ICCP) system implementation project. Your corrosion control contractor used plant piping and construction information to calculate the CP current requirement for all of the plant's buried metallic assets. The CP current requirement was verified, the design package was prepared, installation is now complete, and the ICCP systems are ready to be energized. The iterative process of balancing ICCP system current begins with each rectifier being turned ON at a low CP current output setting. $Cu/CuSO_4$ reference electrode (CSE) potentials are then measured to the buried piping throughout the plant. This process is repeated at incrementally increased levels of the CP current output for each rectifier until optimal balanced CP current distribution and collection is indicated by these CSE readings meeting the NACE referenced corrosion control criterion that your plant has adopted.

The success of any ICCP system in protecting buried piping is certainly dependent on adequate CP current output, but just as important is whether or not the anodes have been properly positioned relative to your plant-site geology and piping configuration.

Knowledge of plant-site geology is crucial to anode placement for efficient ICCP system current distribution. Equally important is understanding the configuration of underground plant structures, such as the buried piping network layout, pipe diameter and burial depth, as well as the anticipated degree of CP current collection on a plant's bare copper cable grounding grid and the steel rebar in building foundations. Plant-site geology and the tremendous number of underground CP current collection possibilities should be the driving force behind decisions regarding where ICCP system anode beds are ultimately positioned and how they are designed.

Ohm's Law, which states that electrical circuit volts [E] equals current [I] multiplied by resistance [R] (i.e., E=IR), controls CP current collection.

In general, the resistivity of bedrock is high, which restricts CP current flow. High circuit resistance [R] of an individual ICCP system forces an increase in rectifier voltage [E] to produce any amount of CP current [I]. In a plant, high CP circuit resistance means that additional rectifiers might be necessary to meet the calculated CP current requirement. So, to achieve efficient CP current distribution in the plant environment, anode ground bed design should always consider plant-site bedrock depth below grade elevation (i.e., ground level).

There are four types of CP anode ground bed configurations that strictly relate to plant-site bedrock depth.

- Deep anode ground beds are usually specified when bedrock is several hundred feet below grade elevation. CP current discharged from deep anodes is anticipated to be efficiently distributed to all buried piping in a plant because it comes up from beneath the piping through the soil in a more or less uniform pattern of dispersed current density.

- Semi-deep anode ground beds might be appropriate if bedrock is one hundred or so feet below grade. CP current distribution from semi-deep anodes is also reasonably efficient, but since these anodes are closer to grade elevation their pattern of discharged CP current density is diminished. Less CP current should be discharged from each of these installations so a greater number of semi-deep anode beds would be required for the anticipated level of balanced CP current density throughout a plant-site.

- Shallow anode ground beds might be called for if bedrock depth is no more than fifty feet below grade. The same amount of required CP current to protect all plant piping must be distributed by even more individual shallow anode ground beds since the CP current density would be concentrated close to grade elevation and so would be more quickly collected after discharge from the anodes by piping and other shallow buried structures near the anode ground beds.

- Distributed anode ground beds would be required if bed rock is very close to grade elevation. A single distributed anode ground bed ICCP system might discharge a lot of current, but each of many individual anodes in the system would only be discharging an amp or two since these anode ground bed configurations are usually installed parallel and very close to the specific pipeline segments that they are protecting.

Once plant-site bedrock depth is understood, the ICCP system designer knows the depth limit for any of the possibly numerous installations that will ultimately make up the overall plant ICCP system. But the CP system design process does not stop there. What must now be evaluated is the configuration of the buried piping network, pipe diameters, pipe burial depths, and CP current collection on a copper grounding grid as well as the rebar in building foundations.

The intent of any ICCP system is to get sufficient CP current to all parts of a plant so that uniform acceptable corrosion protection is realized without over-protecting some areas in order to achieve sufficient protection on others. To accomplish this, the ICCP system designer must visualize how the CP current from each individual anode ground bed will migrate through the soil at the plant-site so that the necessary amount will be collected on the buried piping that is to be protected. This is actually the most challenging part of designing ICCP systems for a plant, since plant areas with a high concentration of pipes or other buried structures might require more CP current than areas with only a few pipes, and shielding can often prevent any CP current from reaching significant portions of the plant's buried piping.

To achieve complete CP current coverage in a plant were shielding occurs, it may be necessary to design and install some of the ICCP systems at depths shallower than the maximum depth defined by the plant-site's bedrock geology. An example of when this should be considered would be plant areas where very large diameter circulating water pipes of either steel construction or PCCP, which has a steel cylinder, are buried deeper than some smaller diameter plant piping. In this situation, Ohm's Law predicts that any CP current coming up from below the large pipes would be collected on the underside of these pipes. So neither the tops of the large pipes nor the smaller diameter pipes above the large pipes would receive adequate CP current. This problem is addressed by the design of shallow or distributed anode beds to be installed above the large pipes that would discharge sufficient CP current to protect the tops of the large pipes as well as the smaller pipes in the area. Deep foundations can also shield CP current from reaching piping between buildings. An ICCP system of distributed anodes might be the only way to improve this condition.

CP current cannot choose to go where it is needed. CP current simply takes the path of least resistance (i.e., Ohm's Law) to get back to the negative side of the rectifier to complete the CP current discharge and collection circuit.

There are two pathways in an ICCP circuit where adding resistance would suggest current might be controlled:

1. Rectifier positive/anode discharge circuits: Adding resistance here is a good approach and can benefit and balance ICCP system output current distribution in many ways;
2. Rectifier negative/structure drain circuits: Adding resistance here is generally a bad idea and can lead to stray current corrosion of piping.

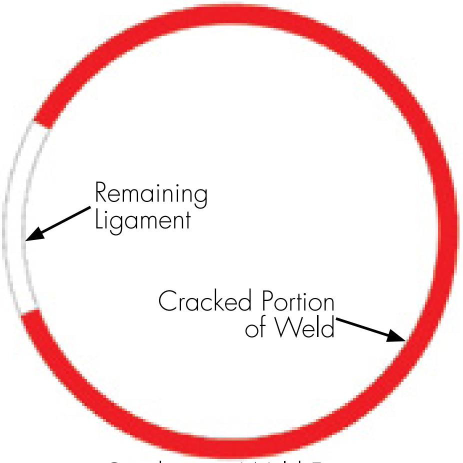
Adding resistance to rectifier negative structure drain circuits is bad because once CP current has been discharged from the anodes and it is in the soil Ohm's Law dictates what path it takes to return to the rectifier. While CP current must ultimately be collected on plant piping that is at some point hardwire connected to the rectifier DC negative, since the buried piping is in the soil, the soil is always an available path for CP current flow. So adding resistance in the negative drain circuit does not guarantee that the CP current will stay on this path (i.e., the piping) due to Ohm' Law. If CP current leaves a pipe to reenter the soil because of lower circuit resistance there will be stray current corrosion metal loss of the pipe at this CP current discharge point.

The only CP current control (i.e., added resistance) that can be effectively applied to an ICCP system is in the anode current discharge circuit. Individual anodes in a deep anode ground bed installation often have resistance added to limit current discharge from specific anodes that are in lower soil resistivities, which can occur over the several hundred foot depth of the active portion of a deep anode bed column. Doing this minimizes premature anode depletion at these low resistivity anode positions and makes the complete deep anode ground bed more reliable over the long term. Such anode current discharge limitation may be part of any CP anode ground bed. In fact, when individual anode circuit resistance is available in a distributed anode system, this level of current control can directly influence how well the ICCP system is balanced to protect local piping.

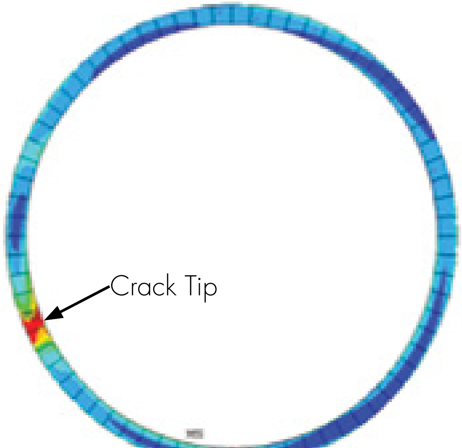
During the commissioning of a new ICCP system, specialized GPS-synchronized rectifier current interrupters are used to balance the impact of CP current in a plant. These interrupters are programmed to cycle each of the ICCP system rectifiers ON and OFF, in a choreographed sequence, while CSE potentials are collected. The individual rectifier CP current outputs are incrementally adjusted in increasing steps, as required, until the CSE potentials meet the plant's corrosion control criterion.

Structural Integrity's NACE certified corrosion control engineers understand these principles and requirements well. We have the experience necessary to properly design and balance for optimum CP current distribution ICCP systems of power plants and other station facilities with a complex network of buried piping. We look forward to sharing our knowledge and working with you to optimize the performance and protection of your ICCP systems.

USING ELASTIC-PLASTIC ANALYSIS TO DETERMINE TIMING FOR REPAIR



Cracking at Weld Face



Stress at Weld Face

By: MATTHEW WALTER
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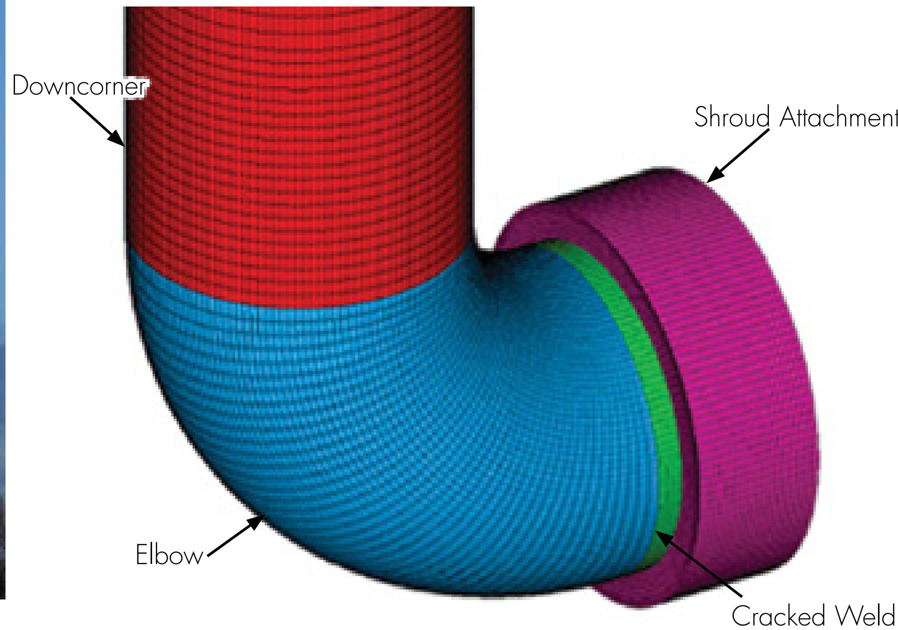
Structural Integrity recently performed an evaluation for a degraded boiling water reactor internal core spray line (CSL) in which several welds contained multiple reportable indications identified during in-service inspections. Traditional flaw evaluation methods were able to demonstrate adequate margin for one operating cycle; however, these methods were not able to show the CSL had adequate margin for the desired two cycle interval. The utility which owned the plant subsequently began to evaluate whether repair/replacement of the affected system was required during the next refueling outage. If necessary, this would result in a multi-million dollar activity. When the utility submitted a request for proposal for engineering actions to address this problem, we offered an analytical approach to investigating if additional structural margin could be demonstrated prior to initiating a repair or replacement (RR) activity. If our analysis showed adequate margin then the RR activity could be deferred, possibly indefinitely.

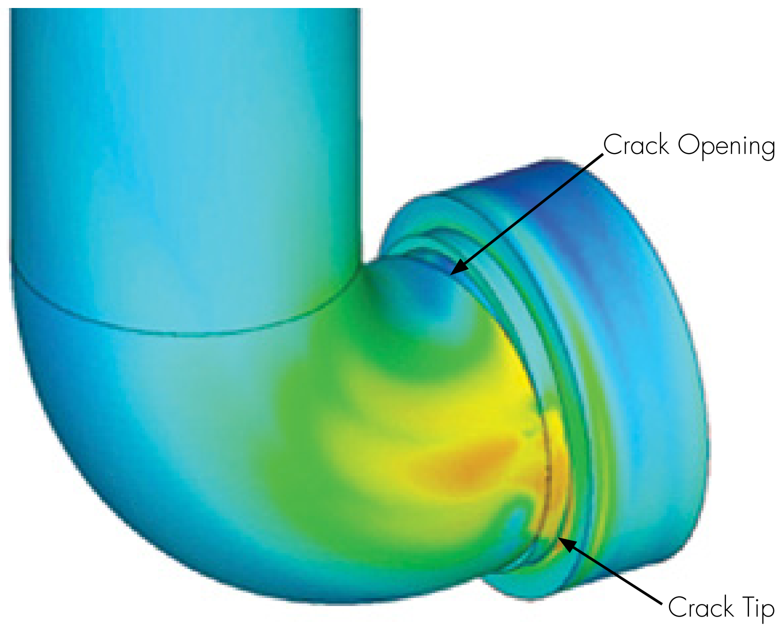
Our understanding of the existing Boiling Water Reactor Vessel and Internals Project (BWRVIP) and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code methods allowed us to identify the inherent conservatisms and simplifications in the original methods used to perform the outage justification for continued operation (JCO). We identified an alternate engineering evaluation method that removed the unnecessary conservatisms while retaining the methodological attributes required by the U.S. Nuclear Regulatory Commission. This resulted in a more sophisticated treatment of the relevant physics while simultaneously retaining the NRC -approved BWRVIP and ASME B&PV Code, Section XI attributes. In order to reduce as much excess conservatism as possible, we performed an elastic-plastic analysis of the CSL with all welds and cracking simultaneously modeled using the ANSYS finite element software. This refined analysis allows the use of contact elements on the crack faces to accurately account for crack opening (which cannot carry load) and crack closure (which can transfer compressive and shear loads, even if cracked). A three-dimensional model of the CSL was built which accurately simulates load orientation, which often times is conservatively simplified in a hand calculation. The elastic-plastic material model used in the analysis allowed consideration of displacement limited secondary loading. It is important to note that the conservatisms removed are not required by the U.S. NRC but are inherent in the simplified methods. These methods are appropriate and should continue to be used as a first step. When necessary, it is also important to understand how to remove them and to understand the additional structural margin inherent in the material and systems structural design that can be credited with a more sophisticated engineering evaluation.

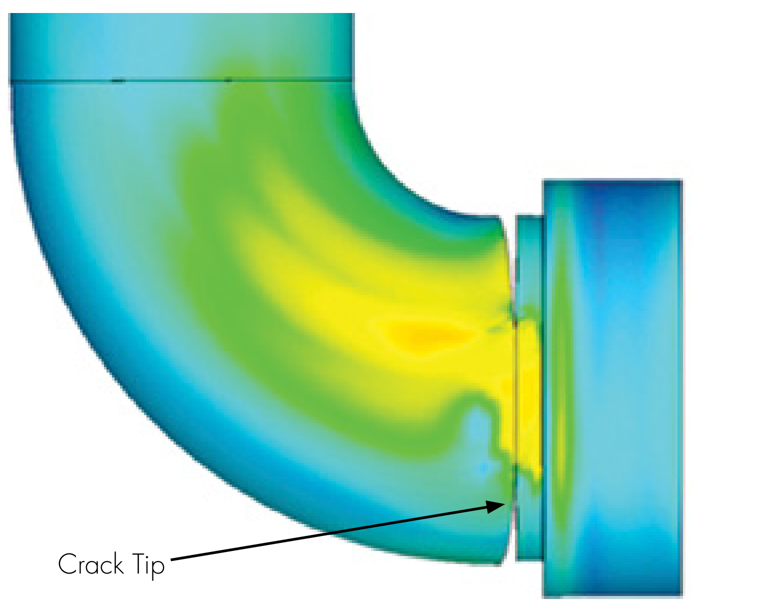


Structural Integrity's analysis was performed in compliance with the NRC-approved BWRVIP-18, Revision 1-A, which uses methods from ASME Code Section XI. Since the CSL has both flux and non-flux welds, appropriate Z factors were used so that a limit load analysis could be performed for the entire CSL. The limit load failure criterion is met if the ANSYS analysis converges (i.e., the model is stable) and the maximum strain is lower than the elongation at rupture specified by the ASME Code. Limit load analysis was performed for various upset and faulted loading conditions which were applied to the model simultaneously. Thermal and seismic displacement loads were a significant portion of the overall loading. Since these loads are secondary in nature and self-relieving, the elastic-plastic model was able to simulate this behavior and show sufficient margin against plastic collapse, even with substantial cracking present in the welds (as shown in the figures).

Leakage was also calculated for each of the cracked welds. By modeling the cracks in three dimensions with contact elements that account for crack opening and closure, an accurate leakage area and corresponding flow rate was calculated. This gave significantly lower leakage rates than would be calculated using a bounding crack opening displacement as would be necessary using the original simplified methods.

The results of this project gave the utility the information necessary to demonstrate that the affected system would retain adequate structural and leakage margin for the desired two cycle operating interval which allowed the utility to consider deferring a RR activity until after the subsequent refueling outage and a subsequent re-inspection of the degraded welds. This result allows the utility to obtain a second set of inspection data that may show the flaws are not growing which would allow for continued deferral of the RR activity.





Using a Health, Consequence, and Confidence Scale to Prioritize and Budget

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Based on projections from the US Energy Information Agency, coal burning plants will continue to be a major contributor to the US power generation mix for the foreseeable future. Since environmental regulations make it difficult to build new plants, existing plants will need to operate for a significant number of years into the future to meet energy demands. To meet this need, it becomes ever more important to determine the health of individual components to help budget and plan for their continued operation.

The boiler has historically been the leading cause of forced outages, so it is a top priority to track the condition of its parts and prioritize analysis and inspections to determine when those parts may need replacement or repair. Structural Integrity has developed a semi-quantitative approach to benchmark the overall health of such components. The resulting health index is used to prioritize replacements, repairs, and further study through inspections and analyses. The end result is then applied to determine capital budgets for equipment replacements and O&M costs for repairs or further study to improve the accuracy of the assessment.

Our approach was recently applied to an aging plant in North America where it was desired to develop long term budgets for both capital and O&M costs. To achieve that, an overall assessment of the health of individual components needed to be performed while prioritizing what areas would need the most attention or at least need attention the soonest. While we can't provide specific details of that assessment, the examples are representative of the study performed.

Our process begins with the collection of available information for the boiler, which would typically include:

- Component drawings
- Design data
- Details of any design changes, repairs, or replacements
- Historical and current operating data for each component
- Fuel analysis
- Water chemistry control program and recent analysis results
- Inspection reports
- Metallurgical reports – both routine tube samples and failure investigations

An important part of the information review is a site visit to collect documents, perform a brief walkdown of the unit, and most importantly, we interview site personnel to collect information regarding plant issues and history.

We review the information for each individual component, and we summarize the findings in a consistent, easy-to-read format using Component Assessment Snapshots, an example of which is shown in Figure 1. The key information in the snapshot is:

- Component identification and summary of service history and replacements.
- List of potential damage mechanisms for the component type, along with an indication of whether there is evidence that each damage mechanism has been active, and to what extent.
- Details of component geometry including tube/header dimensions and materials.
- Sketch of drawing of component indicating locations of significant NDE test results, failures, etc.
- Description of any life estimation calculations performed for the component. The nature of life estimation performed depends on the type of component, the identified operative damage or failure mechanism, and the available information. For example, for the final superheater and reheater sections, a tubing life estimate is made considering the effects of steam temperature, pressure, and flow, an estimated or assumed heat flux, internal steam oxide formation, external wall loss due to erosion or fireside corrosion, and creep of the tubing material. The specificity of the calculation depends strongly on the amount and nature of input data, e.g., penthouse tubing oxide thickness data indicating temperature variations across the boiler, fireside corrosion rate information from wall thickness measurements or tube sample examination results, etc.
- A descriptive summary of issues discovered during the information review and life assessment calculations, including a description of any key data missing and needed to draw substantive conclusions.
- Numerical ratings of overall component condition (asset health index), consequence of component failure, and confidence level of the performed assessment. These ratings are qualitative, based on engineering judgment and our past experience with similar components. The asset health ranking ranges from 0 (needs immediate or very-near-term replacement) to 10 (component in like-new condition with no issues); the failure consequence ranking ranges from 1 (personnel safety risk) to 5 (little consequence – unit can continue to operate); and the confidence level rating ranges from 0 (low confidence in results, with very little data available) to 5 (high confidence in results).
- A list of recommended actions either needed to improve the confidence of the assessment, to continue monitoring the damage development, or to repair or replace possibly damaged components.
- A summary list of documents reviewed relative to the specific component.

Continued on next page

COMPONENT	ASSET HEALTH INDEX 0 = very poor 10 = like new	FAILURE CONSEQUENCE RATING 1 = severe 5 = minor	CONFIDENCE IN ASSESSMENT 0 = poor 5 = very high
Boiler feedwater piping	3	3	3
Furnace waterwalls	7	2	2
Superheater assemblies	5	4	4
Superheater outlet header	7	3	2

Table 1. Example Component Rating Summary

COMPONENT	RECOMMENDATIONS	
	Action item	Priority
Boiler feedwater piping	■ Perform FAC assessment.	*High*
Furnace waterwalls	■ Perform a tube wall thickness survey in areas prone to fireside corrosion to establish current condition. ■ Metallurgical evaluation of tube samples taken from panels removed during next outage.	*High* *Medium*
Superheater assemblies	■ Measure oxide thickness in penthouse for outlet terminal tubes. ■ Remove furnace tube samples for analysis. ■ Inspect for oxide scale accumulations in outlet pendant loops. ■ Inspect a sampling of DMWs, take tube sample.	*High* *High* *Medium* *Medium*
Superheater outlet header	■ Re-inspect outlet header girth welds using advanced ultrasonic techniques next or following major outage.	*Medium*

Table 2. Example Component Recommendation Summary

Once the individual Condition Assessment Snapshots have been completed, we compile the information contained in them into a summary, typically at the beginning of an overall unit report containing a collection of snapshots. The key elements of the summary are tables listing the component rating results, the predicted remaining lives (where available), and prioritized, recommended inspection actions judged necessary to either confirm current condition or obtain data/information needed to improve the confidence of remaining life predictions. Tables 1 and 2 are example component rating results and recommendation summary.

This approach to a boiler condition assessment program establishes a succinct picture of the overall health of the boiler, what components and locations represent the highest risk for forced outages, and what near-term inspections would be most effective to increase the assessment confidence.

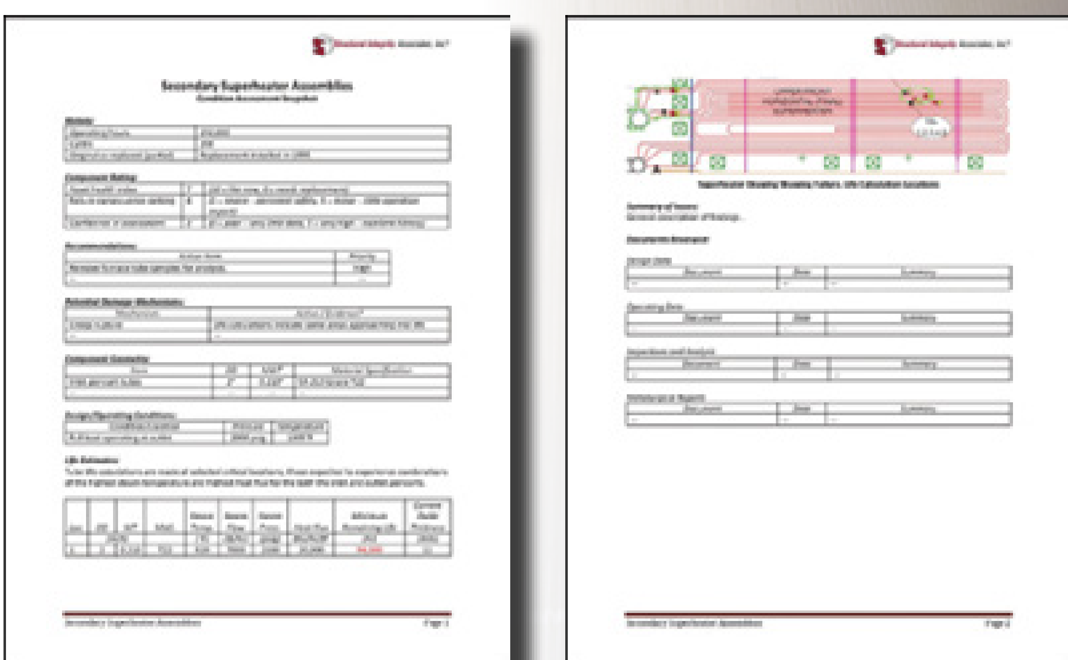

Figure 1. Example Condition Assessment Snapshot.

PARTNER WITH ASNT

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Structural Integrity is a long-time corporate partner in the American Society of Nondestructive Testing (ASNT), and many of our NDE Professionals have served as officers in their local sections, as well as on committees at the national level. David Dechene currently serves on the Ultrasonics Committee, SNT-TC-1A Review Committee, and Guided Wave Testing Committee, while Dr. Jason Van Velsor serves as the Vice Chairman of the Guided Wave Testing Committee.

Recently the Charlotte ASNT's January 2016 meeting was an Introduction to Phased Array Ultrasonics class held at Structural Integrity Associates in Huntersville, NC. The 8-hour class was held on Saturday, January 30th, and was taught by Jeff Milligan with assistance from Randy McDonald and David Brawn. Fifteen attendees from several local companies and students from Central Piedmont Community College spent the first half of the day learning about phased array UT theory and the second half of the day practicing hands-on exercises with our state-of-the art phased array equipment. We have offered this Introduction to Phased Array Ultrasonics course to the Charlotte ASNT six times since 2009.

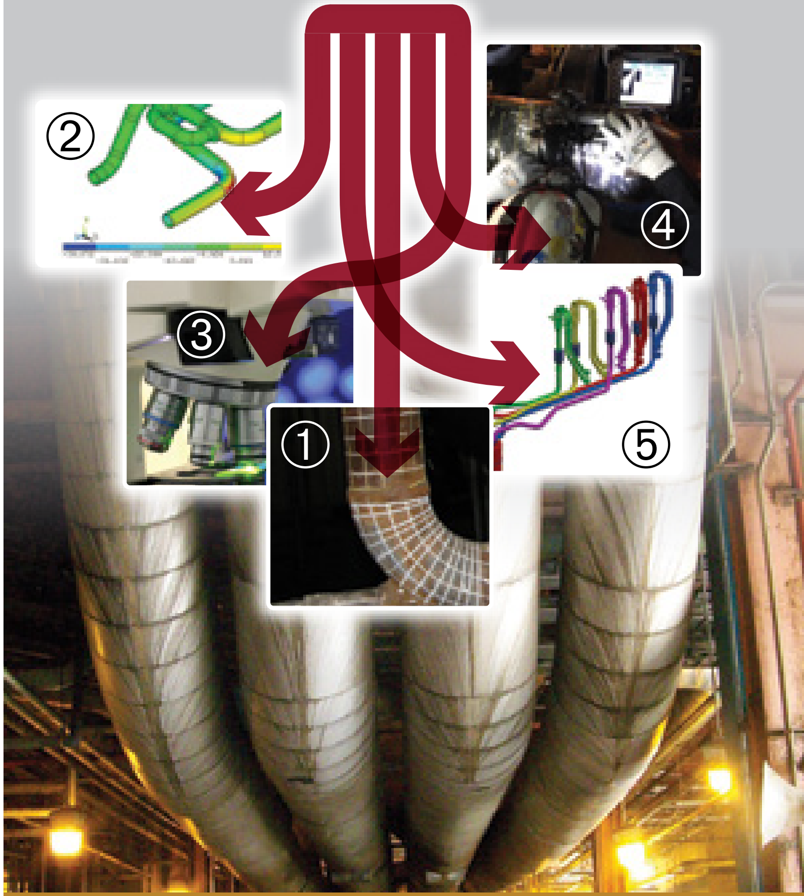
In addition to the phased array training course, Structural Integrity is a regular presenter at local ASNT meetings around the country. Recent presentation topics have included Ultrasonic Guided Wave Technology, Electromagnetic Acoustic Transducers (EMAT) and Pulsed Eddy Current (PEC) technologies. The March 2016 Charlotte section meeting was also held at our Huntersville office with an HDPE Piping Inspection presentation by Michael Lashley and a demonstration of our automated HDPE scanner and phased array ultrasonic inspection technique.

CHECK OUT OUR HEP WEBINAR SERIES FOR THE FOSSIL INDUSTRY

During the month of February, we presented a High Energy Piping Integrity Management webinar series for the fossil industry. Since these are critical systems at both combined cycle and traditional fossil fired power plants, we offered the five free, 30-minute, educational webinars to help you.

Now you can watch any of the below webinars at your leisure. Visit www.structint.com/webinars and access them under the fossil section.

❶ Building Blocks of High Energy Piping Program
❷ Stress Analysis and Lifing Calculations for HEP Programs
❸ HEP Metallurgy: CSEF and Low Alloy Steels
❹ NDE Techniques for High Energy Piping: Detecting Creep Damage
❺ Managing Data and Knowledge for HEP Integrity



INSPECTING OLD, LARGE, INACCESSIBLE PIPING SYSTEMS

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Both nuclear plants and hydroelectric plants depend upon the uninterrupted flow of large quantities of water to reliably provide electricity with no greenhouse gas emissions. Therefore, both types of plants are highly susceptible to one of the simplest and oldest forms of degradation known to modern man – corrosion. More specifically, both are plagued by internal corrosion of carbon steel piping exposed to untreated water supplies.

The similarities don't end there. Virtually all hydro facilities are old, with some hydro plant "penstocks" the big (often really big) pipes that convey water from a higher elevation to the power house at a lower elevation, dating back to the early 20th century. While not that old, the service water system pipes in most US nuclear plants were first wet-out in the 1970s and have been exposed to local raw water (and have been corroding) ever since. In both types of plants, carbon steels or other non-inherently corrosion resistant materials are the materials of construction. Both types of plants will have both buried and above ground portions. In both types of plants, the piping systems are far too large to inspect more than a tiny fraction of the surfaces.

Of course, there are some differences, as well. Penstocks are typically coated on the OD and lined on the ID to resist, or at least to delay, corrosion, while most nuclear plant service water systems (SWSs) are coated, but not often lined. SWSs are usually of welded construction, while penstocks may be welded but are typically riveted with both longitudinal and circumferential seams.

There are some other key differences between penstocks and nuclear plant service water system piping. Penstocks were often built from low toughness materials (e.g., wrought iron, "semi-steel"), riveted construction is common, and probably most importantly, penstocks can rupture. While access to nuclear plant SWS piping, especially buried piping, is difficult, the large diameters (>100" is not unusual), very remote locations, and often extremely steep terrain make access and inspection of many penstock locations exceptionally challenging, as illustrated in the overview photo at right. To gain an appreciation for how steep this particular example is, note that the electrical transmission lines in the photo are essentially horizontal. The example shown is for a penstock that ranges from 138" to 147" in diameter, with shell thicknesses from 9/16" to 7/8" over the 1,859' length.

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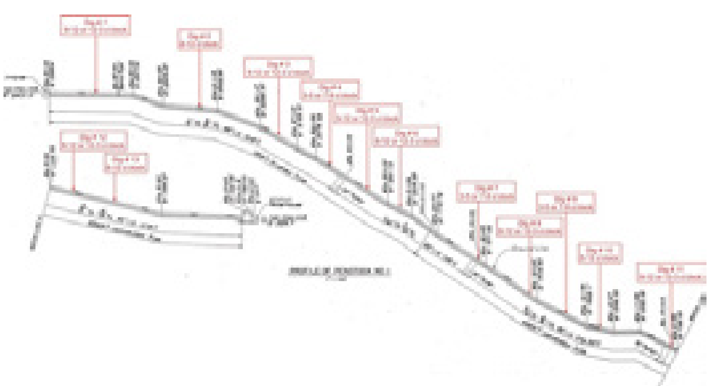
INSPECTING OLD, LARGE, INACCESSIBLE PIPING SYSTEMS

CONTINUED

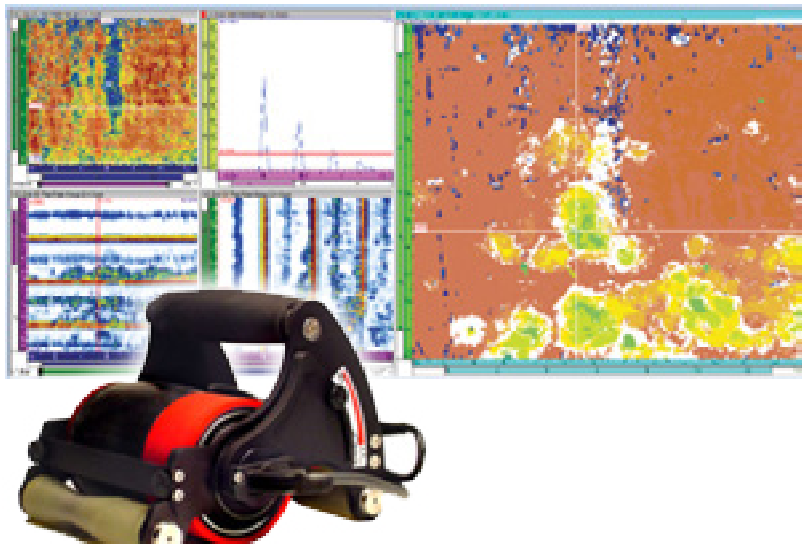
The image on page 32 shows a rope access trained UT technician performing a 180° examination on a 147” penstock that lies at a slope greater than 45°. In addition to UT certifications, trapeze skills are a plus for such inspections.

The ultimate question to be addressed for penstocks is similar to that for nuclear plant SWS piping: How best to determine the structural integrity (resistance to net section collapse) for a structure that has been corroding for a long time? The approach to answering that question is also similar for both types of plants, involving a combination of selective inspections and statistical analysis to make informed judgments about present and future integrity of the piping.

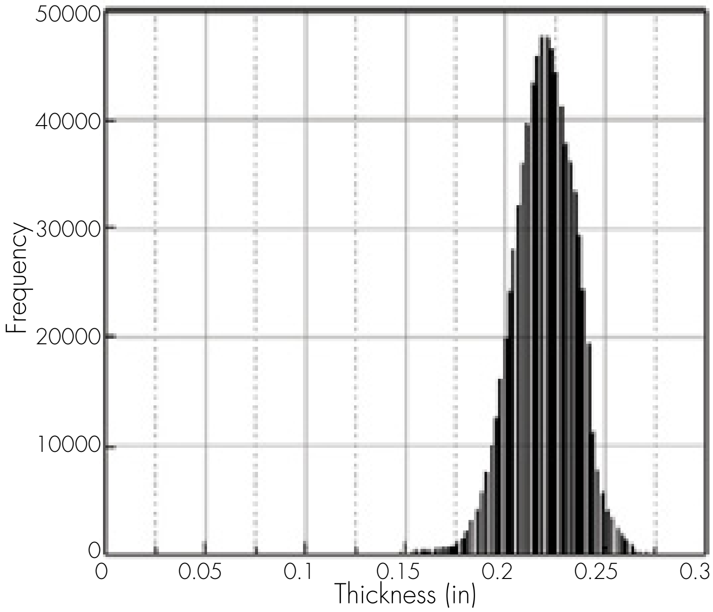
For hydroelectric plants, Structural Integrity uses a statistically-based approach to select a sampling of locations for inspection. Even though the number of locations to be inspected is very restricted, the sample must be sufficiently complete to provide the required characterization of structural integrity for the system. This means the sample must be sufficiently large and sufficiently diverse to allow determination of the statistical thickness (or metal loss) distribution with a high level of confidence. The resulting sample selection may look like that below.



For penstocks, inspections are done on 18” wide (axial direction) by 90° or 180° of circumference sections with a phased array UT wheel probe that provides a very high resolution such that pits or cracks can be detected and characterized. Tens of thousands of individual thickness determinations are collected per inspection location. The



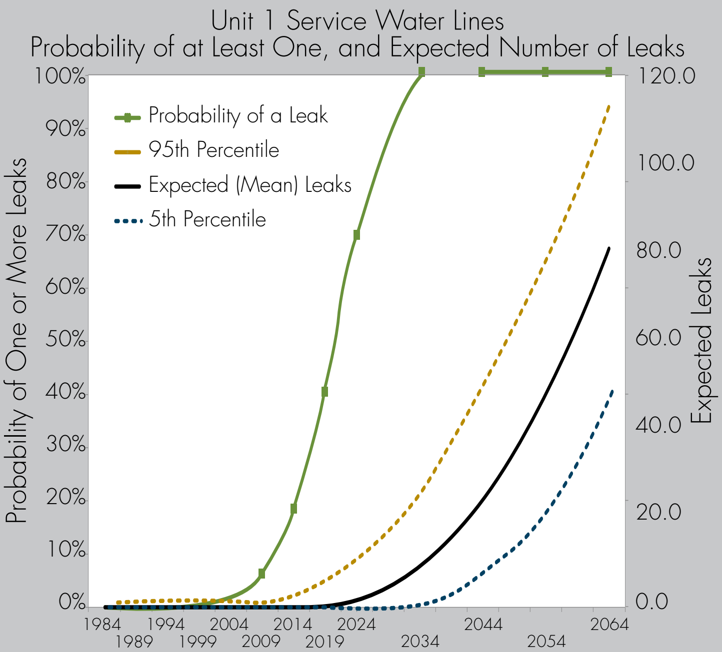
primary post-inspection activities involve analysis of the huge amount of data that is collected. The example below shows the distribution of ~800,000 wall thickness measurements from a sampling of 114” (circumferential) x 18” (axial) inspection locations.

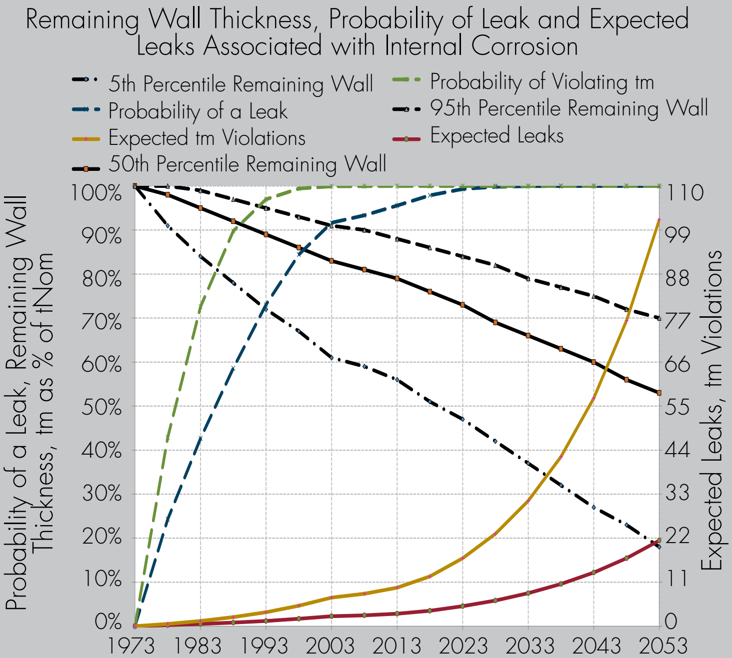


The approach for SWS assessments and inspections at nuclear plants is highly comparable, though typically with SWSs there is insufficient inspection data available to develop a thickness distribution that can be relied upon with a high confidence level. In this case, other analysis tools are necessary. Structural Integrity has developed the **ACCORDION** (**AC**cumulation of **COR**rosion **D**amage evolut**ION**) probabilistic corrosion modeling tool to assist in Life Cycle Management (LCM) assessments of systems such as the SWS. An LCM assessment, using our ACCORDION tool, provides:

- Guidance on the severity of the overall condition of the system, quantitative estimates of past, present, and future condition, and guidance for decision making on selection of mitigation alternatives and timing of the application of those alternatives.
- Identification of "hot spot" segments to direct future inspections.
- The ability to incorporate new information, such as the results of new inspections, to further refine the model to improve its predictions. Screening inspections can also be done using Long Range Guided Wave Testing (GWT), and the GWT results can provide further guidance on where to look with higher resolution tools.

The following figures provide examples of the output of the ACCORDION modeling tool.





Lessons learned from extensive experience with inspection and assessment of power plant piping include:

- "Front end" hours are well spent. Planning of inspections is crucial to reduce the number of inspections necessary to provide an accurate assessment.
- While a sufficient sample of high-resolution inspections, such as those typically performed on penstocks, can "generate their own statistics" with no need for assumptions regarding the shape of the underlying distribution. Probabilistic statistical modeling tools can be used to supplement limited inspection data and provide good estimates of piping condition.
- However, more data is always better. A good assessment should not only point out areas of potential structural concern, but also suggest areas where further inspection should be targeted to improve the reliability of the assessment.

While both nuclear and hydroelectric plants have their unique challenges, the bottom line is that for both types of water delivery systems, we have successfully completed and will continue to provide analysis and inspection for "the prevention and control of structural failures".

Add Creep and Fatigue Tracking to an M&D Strategy through Integration of Online and Offline Data

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Many power companies have recognized the economic benefit of implementing online monitoring and diagnostic (M&D) systems into their plants. The advancements in sensor technology, signal transmission (wired or wireless), data storage and computing power, allow for ever more cost-efficient collection and analysis of 'Big Data'. Most commonly this data is analyzed to optimize plant heat rate, or to identify patterns in instrument signals that might be indicative of instrument failure (increased frequency of anomalous readings) or degradation of a component (vibration spectra outside of a pattern of acceptable limits).

These M&D systems have helped utilities reduce their operating costs, caused by inefficient thermal operation or unplanned outages. In addition to these day-to-day savings, there is increasing recognition of the potential for mid- to long-term savings, which can result from making use of the collected data for an optimized maintenance strategy. That is, rather than inspecting whole systems on a fixed schedule basis, inspection scopes and schedules can be optimized based on actual condition. While such condition based maintenance (CBM) exists for components based on offline assessments and data collection, the advances in sensor technology and associated transmitters now allows for real-time evaluation of condition. This real-time assessment may be based on direct monitoring of damage (e.g., loss of wall thickness), or may be inferred from damage models that use data from various sensors to estimate damage accumulation for cases where the primary damage mechanism cannot be easily monitored directly (e.g. creep or fatigue). Therefore, this new paradigm requires both diagnostic capabilities (What damage is occurring?) and prognostic capabilities (When will failure occur?). Increases in computing power, combined with improvements in damage models now make prognostic component assessments possible, thereby allowing better maintenance planning for components that could previously only be managed with offline inspections and assessments.

This Integrated Asset Health Tracking approach provides tools to predict remaining component life, by making use of online data provided by the M&D infrastructure, and offline data about a component's health history. As shown in Figure 1, there are three time-dependent sources of data content taken into account: Specifications, Events and Monitoring. A suitable analogy is monitoring our own health. Doctors can give us a much better diagnosis and prognosis if they not only monitor and track our vital signs, but also know our personal and family health history; and combine these data sources to track our health.

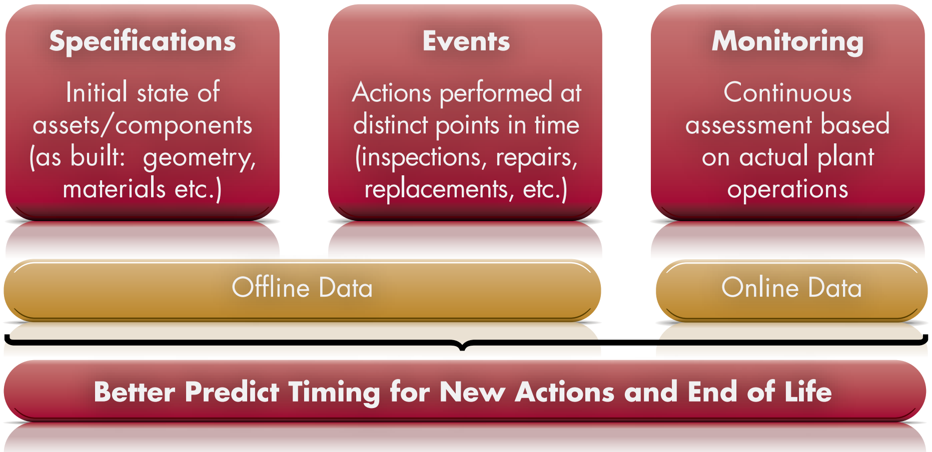


Figure 1. Sources of data content to be considered for remaining life prediction

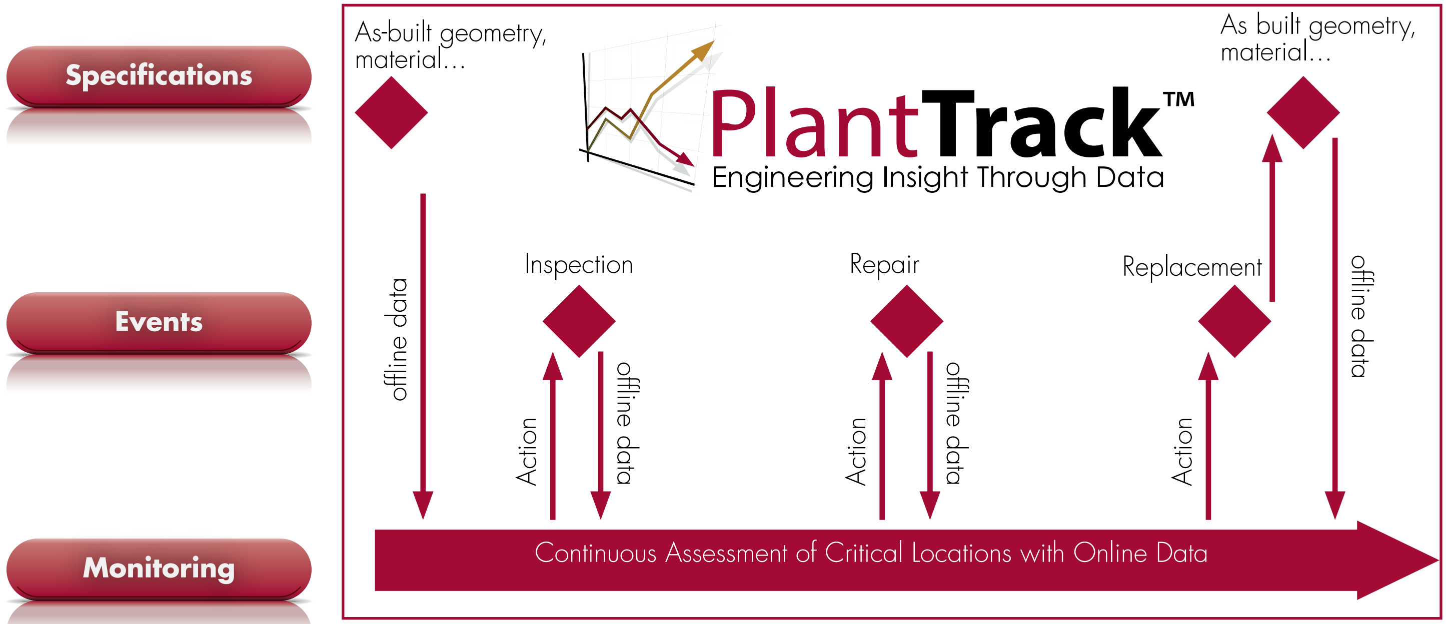


Figure 2. Integration of offline and online data for continuous component health assessment

We have incorporated a number of online prognostic damage accumulation tools into our PlantTrack software to provide an integrated environment for tracking fossil plant component health and condition. These online monitoring and analysis modules combine the stored offline data with online data from actual operation for continuous health assessment of critical components (Figure 2).

An example of the integrated analysis of offline and online data is our Creep Monitoring Module which can be applied to boilers and High Energy Piping Systems. Using actual component data (e.g., wall thicknesses or material properties as found during inspection) in combination with online operating data allows for the continuous determination of actual creep damage. Figure 3 shows an example from a power plant, where we have implemented the Creep Monitoring Module with PlantTrack for monitoring several critical piping locations. The red line in the Creep Damage Trend Chart shows the creep life consumption in a percentage of overall component life. We analyzed the predicted remaining hours of component life as well. This information can be used for planning future maintenance work; only at the areas where and when a need is predicted. The benefits are many with the most important being:

- reduction of overall inspection and maintenance costs
- more accurate planning of mid- to long-term budget needs
- reduced risk of catastrophic failures

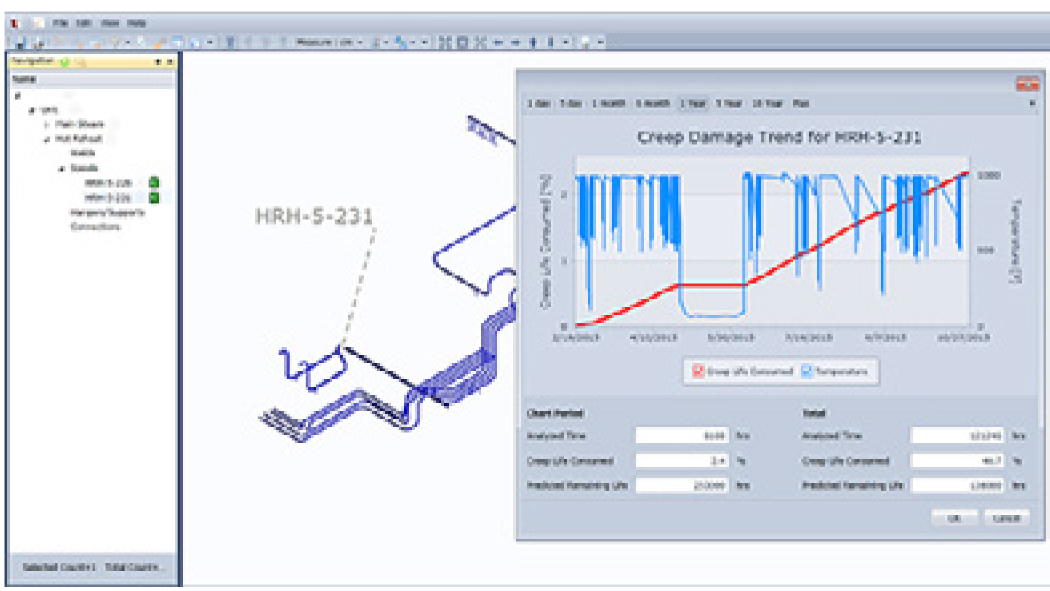
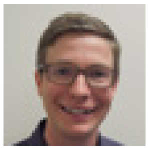


Figure 3. Online creep damage monitoring of critical piping location

HOW TO AVOID VIBRATION FAILURES WHEN MAKING ENGINEERING CHANGES



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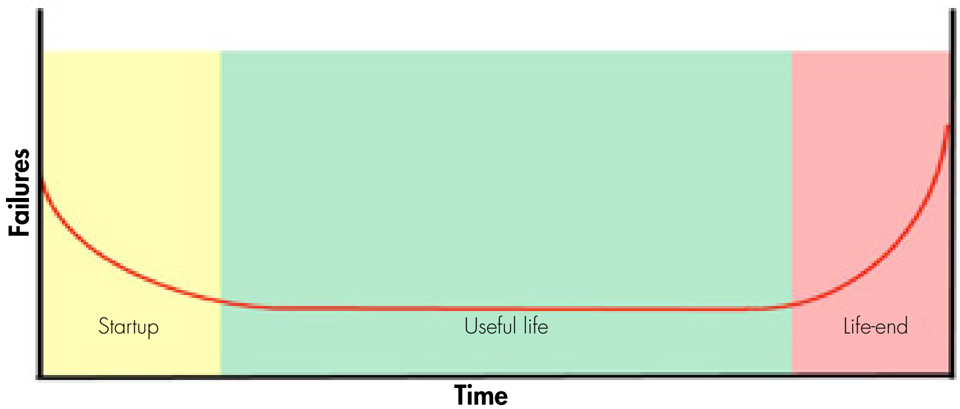


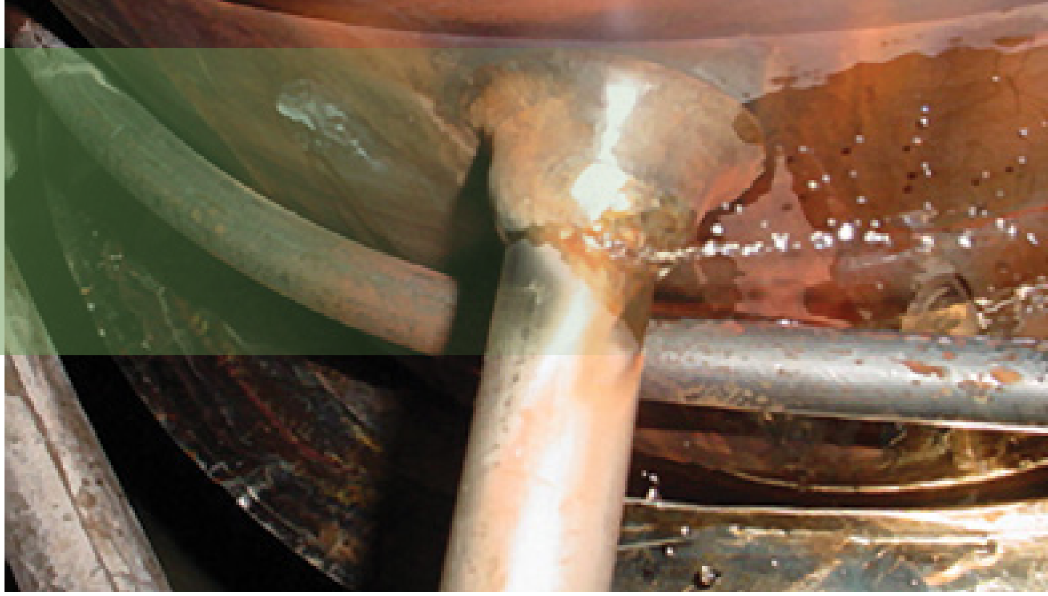
Figure 1. Reducing Failures and O&M Costs Requires Vibration Assessments in the Design and Testing Phase

As the age of systems, structures, and components (SCCs) in nuclear power plants increase, so does the level of effort and cost to manage their aging. Half of the nation's nuclear plants are over 30 years old with essentially all of the remainder older than 20 years. Many stations have undergone significant upgrades to their turbines, pumps, and condensers; each time, increasing operating life and adding efficiency in an ever-challenging power generation market. Within the large engineering design packages for modifying these components, how often have you seen a vibration evaluation of the affected small bore piping? These small bore piping evaluations are being overlooked or improperly analyzed and the consequences, including loss of generation and increasing O&M costs, are trending into the red.

Most of the leaks on small bore piping (<2" OD) causing loss of generation occur because high cycle fatigue (HCF) was not identified or analyzed properly in the design phase reference (INPO IER 14-30). When major rotating or piping components are repaired, modified, or replaced, the forcing function and/or system response is likely to change. Although there had been no history of vibration failures prior to modification, the potential for resonance-induced failures increases significantly post-modification. This isn't a new phenomenon. Early catastrophic failures due to vibration occurred during the early days of plant operation. However, the cost of such a failure has increased dramatically from the view of public perception. Added regulation, and operating expense. Furthermore, resonance induced vibration failures often occur within a fuel cycle, from initiation of a crack to leakage, making early detection increasingly difficult. This means that in order to reduce the number of leaks caused by HCF, a station must become more effective in evaluating the HCF susceptibility of designs and initial testing during operation (Figure 1). Although much of the experience has left or is leaving your mechanical or civil design groups, there are a few tools or key indicators to help you reduce the probability of HCF failures.

In many cases the engineer of choice (EOC) provides the calculations to support an engineering change package. There are plenty of vibration techniques these firms and plant personnel have at their disposal. Hand calculations (i.e., EPRI's Fatigue Management Handbook), finite element (FE) models, and vibration testing offer great insight when evaluating HCF potential early in the design stage when the cost and risk of a failure is low. However, for small bore line evaluations, small inaccuracies or apparent conservatisms can significantly affect the dynamic response in a model or calculation. For example, running a piping model with thermally conservative boundary conditions may achieve a bounding thermal model for ASME NB3600 Eq. 11, but can have inaccuracies of more than 20% during a modal analysis - which can be the difference between failure and a full fuel cycle of operation. If the EOC and/or station is lacking the vibration expertise to properly define the vibration loads and evaluate the responses, experts should be involved to capture these nuances early, before the design makes it into operation. Although models generally provide the earliest indicator of a vibration problem, remember every model is an approximation of the vibration response, with some closer than others. Fortunately, there are easy ways to add confidence to a design model through complementary post-modification testing.

Two different types of testing can be effective in reducing the likelihood of a HCF failure on small bore piping. The first, impact testing, provides accurate insight into system natural frequencies, allowing for a comparison to predicted excitation frequencies. If these align



sufficiently (Ω/ω = 0.8 – 1.2, Figure 2), there is an elevated potential for a resonance-induced HCF failure. Now, an FE model can produce a modal analysis with a couple mouse clicks; however, the accuracy of those results can vary widely. Accurate boundary conditions and non-linearity are captured when impact testing as-built designs and when tested properly, they can be counted on for their accuracy. Furthermore, during testing, field adjustments such as temporary support or mass additions can be utilized to tune the small bore piping outside of exclusion zones and quickly evaluate HCF improvements to the design. The +/-20% exclusion zone criteria may not be achievable and additional reasonable assurance might be needed. The ASME NB-3600 Code states, categorically, "the designer shall be responsible, by design and by observation under startup or initial service conditions, for ensuring that vibration of piping systems is within acceptable levels." This testing during the initial operation of the system/component provides the final insight into HCF failure susceptibility.

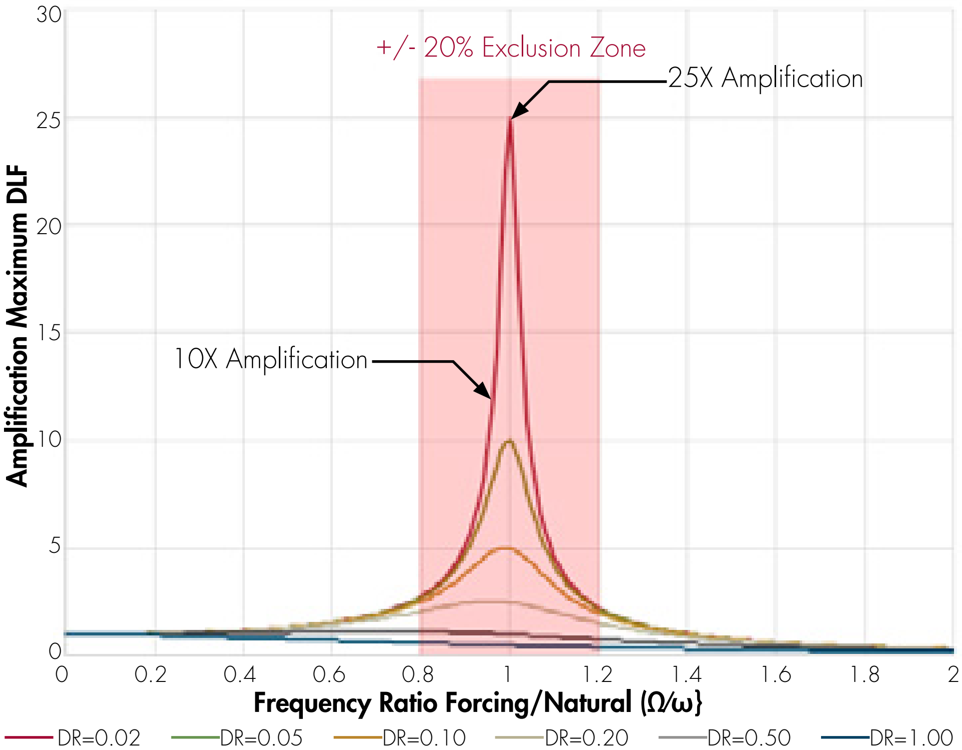


Figure 2. Designing System Natural Frequencies Outside of Exclusion Zones: Vibration Amplification Effects

Operational testing, by handheld systems or other temporary installations can be used during the early stages of operation to measure the vibration levels of modified or affected small bore piping. These methods do not require permanent installations and often can be installed, acquire data, and removed in a couple shifts capturing the data necessary to evaluate a design. The measurements, along with ASME Operations and Maintenance Guide Part 3 velocity acceptance criteria, provide a quick method for evaluating vibration levels.

There are multiple stages during a design or modification package where the EOC and/or station personnel have an opportunity to evaluate vibration. The earlier this evaluation occurs, the more cost effective design changes are to implement and the lower the likelihood of HCF failure. For this reason, the techniques and testing indicators suggested in this article provide successive tasks, each contributing towards the ultimate goal of reducing the likelihood of an HCF failure to an acceptable level. The execution of a vibration evaluation using this strategy allows for subsequent tasks to be assessed on a line-by-line basis, and executed only to achieve the desired level of reasonable assurance for structural and leakage integrity. For example, portions of small bore piping affected by a modification may only require post modification impact testing and a quick visual assessment of the vibration during initial operation due to their overall lower HCF susceptibility assessed in the design. However, some lines may exhibit a greater HCF susceptibility during the design evaluation and impact testing phases, such that vibration measurements may be needed to justify proceeding with operation. Tailored small bore evaluations for vibration, built upon accurate susceptibilities and risk, have proven effective in driving down loss of generation and O&M costs caused by HCF failures.

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TRAINING CALENDAR

MAY 05
Fuel Manufacturing Issues Affecting Performance
San Diego, CA

AUG 02
Plant Vibration Fundamentals and Solution Development
San Jose, CA

AUG 23
ASME Section VIII - High Pressure Vessel Design by Analysis Huntersville, NC

TRADESHOWS

NAES Operations & Maintenance Managers Conference
New Orleans, LA *May 16*, Stop by our booth

NEI Nuclear Energy Assembly (NEA)
Miami, FL *May 23 - 26*, Stop by our booth

UDH LDPE Plant Improvement Conference
Denver, CO *June 6 - 8*, Exhibit, Present and Sponsor

EPRI Nondestructive Evaluation Technology Week
Savannah, GA *June 20 - 24*, Stop by our booth

AREGC - Annual Association of Rural Electric Generating Cooperatives Conference
Vail, CO *June 26 - 29*, Stop by our booth

ASME Pressure Vessels & Piping Conference (PVP)
Vancouver, BC, Canada *July 17 - 21*, Exhibit and Present

SGA Operating Conference & Exhibits
Houston, TX *July 25 - 27*, Stop by our booth

EPRI Service Water Assistance Program Annual Meeting & Vendor Expo (SWAP)
Denver, CO *July 25 - 29*, Exhibit and Present

PennWell HydroVision
Minneapolis, MN *July 26-29*, Exhibit and Present

AEP BRO Forum (Boiler Reliability Optimization)
Columbus, OH *August 1 - 4*, Stop by our booth

EPRI International Light Water Reactors Material Reliability Conference
Chicago, IL *August 1 - 4*, Exhibit and Sponsor

EPRI Turbine Generator Users Group (Summer)
San Diego, CA *August 8 - 12*, Stop by our booth

ANS Utility Working Conference and Vendor Technology Expo
Amelia Island, FL *August 14 - 17*, Stop by our booth

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