2017

VOLUME 42

Structural Integrity Associates, Inc.®

NEWS & VIEWS

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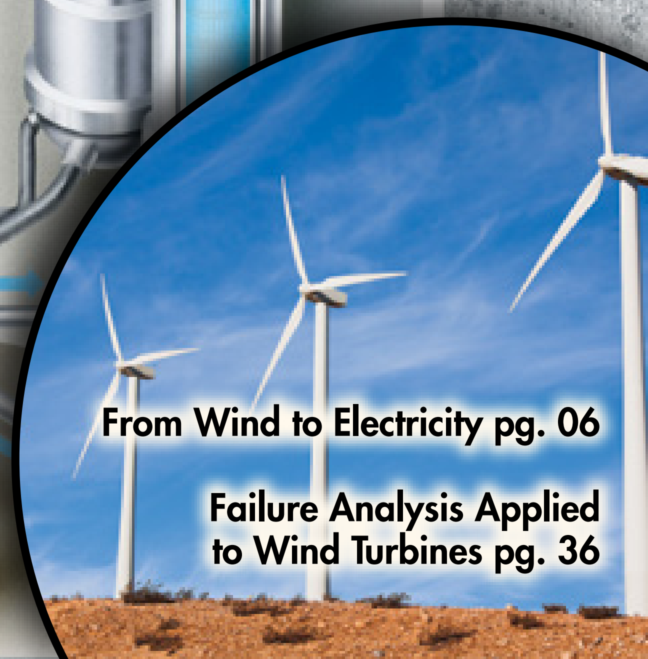

Structural Integrity Associates, Inc.®

By: LANEY BISBEE, P.E.
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Decades ago as a very young engineer, I remember the saying 'The solution to pollution is dilution'. It sounded so clever to a naïve and inexperienced engineer. Today, there's a new saying 'The solution to stagnation is innovation'. It doesn't rhyme as well, but it's no less true. The electric power industry has been moving in recent years to new technology, including Smart Meters (a recent report I read stated that 65 million have been installed and are in use in homes today), Smart Grids and even Smart Cities. There are rapidly expanding wireless sensor-based monitoring systems and augmented reality technology for training. The list is long and touches every aspect of the industry.

Specifically, for power generation, we're now seeing real progress:

- Solar installations are expanding exponentially, from residential to commercial to utility scales
- 2016's utility-scale Wind project development and construction will add approximately 20GW of wind capacity to the current U.S. capacity of 75GW
- Small Modular Reactors continue to inch closer to reality (NuScale recently made history with completion of the first ever Small Modular Reactor Design Certification Application)
- Internet of Things (IoT) is making in-roads to power plants, with numerous platforms evolving to aggregate and analyze data from sensors

I expect that all our clients understand that Structural Integrity's (SI's) business is rooted in keeping the old assets operational as safely and reliably for as long as possible and/or as needed. But do you know that we also apply our knowledge, built upon decades of understanding plant design, operations, maintenance, codes and regulatory requirements, damage development and aging and even repair strategies, to drive innovations in new generation facilities as well as current plants? Well, I'm proud to say that we do.

We are currently involved, or have been recently, in a wide range of innovative approaches to new plants. A short sampling includes SMR fuel and structures design, optimizing the design of thermal solar facilities, performing design studies for heat recovery steam generators and piping systems of next generation combined cycle plants, qualifying new electrical connectors for harsh environment service and in inspecting high level waste and spent fuel storage canisters. While the former list is about plants and components, we're also applying our knowledge to exploit the Internet of Things; something that's useful for new and old plants alike. We're currently incorporating remote sensors and developing applications to provide enhanced online life consumption tracking. SI has a long history in this domain, dating back to our work with EPRI's FatiguePro and Creep-FatiguePro monitoring systems. Today's technology allows us to make a step change in such systems. In addition, we continue to evolve Nondestructive Examination (NDE) technology with non-mechanized encoder systems for NDE, NDE for the inspection of newly installed HDPE pipe and various data and knowledge management systems to capture, manage, and analyze critical system and component information.

At Structural Integrity Associates, Inc., there's no problem that stagnates as we are constantly innovating.

24/7/365 SERVICE

With 43 planned U.S. nuclear plant outages this spring, compared to 23 last Fall and more than any season since Spring 2011, Structural Integrity Associates, Inc. is planning our outage support accordingly.

We have aligned our Senior Staff as Single Point of Contacts for each upcoming refueling outage, and are communicating those assignments and contact information to the impacted plants. You're also encouraged to contact any Structural Integrity associate you've worked with in the past, or make use of our toll-free number, **877-4SI-POWER**.

Some of the most common outage issues we support include:

- Operability Evaluations
- Flaw Tolerance Analysis
- Repair/Replacement Design and Relief Requests
- Welding, Materials and Fabrication
- Vibration Monitoring and Analysis
- NDE Support
- Third-Party Reviews
- Failure Analysis/Root Cause Analysis
- Water/Reactor Chemistry
- Radiation Source Term
- Fuel Failures
- Electrical Equipment/EQ

Call us anytime 24 hours a day, 7 days a week, 365 days a year at **877-4SI-POWER** for a live answer when you need us most!

CYCLE CHEMISTRY AND FAC TRAINING

When: June 27 & 28, 2017
Where: Cincinnati, Ohio
Embassy Suites Cincinnati – RiverCenter
(Five minutes from downtown Cincinnati)
10 East Rivercenter Blvd.
Covington, KY 41011

Cycle chemistry at fossil (including combined cycle) plants influences a high percentage of the availability, reliability, and safety issues the plants experience. To provide technology transfer in this area and increase the awareness of issues and solutions to the associated effects, SI will be presenting a training class for Cycle Chemistry and FAC in June. Topics to be covered include:

- Basic Cycle Chemistry
- Effect of Chemistry Control
- Basic Understanding of Oxide Growth
- Overview of FAC in Fossil and Combined Cycle/HRSG Plants
- Special Case of FAC in Air Cooled Condensers
- Inspection and NDE
- Optimum Approaches, Solutions and Repair Options
- Case Studies
- Questions and Answers

Additional details to be made available soon

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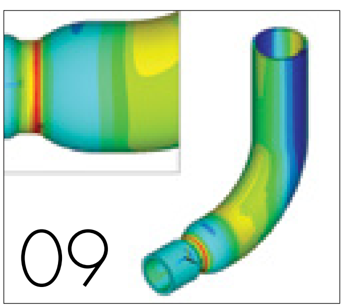

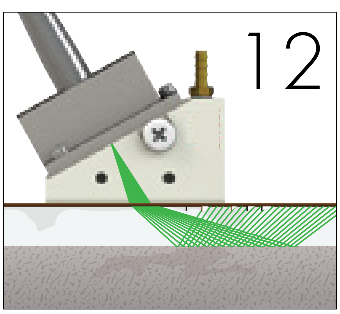

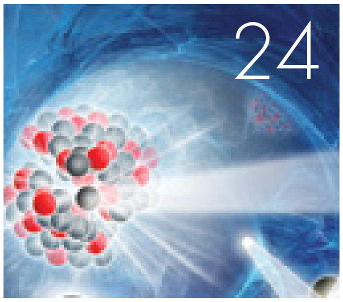
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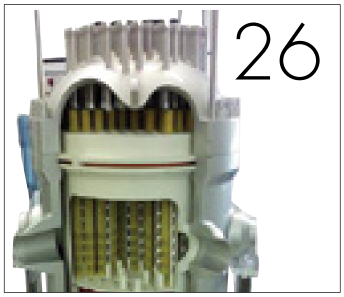
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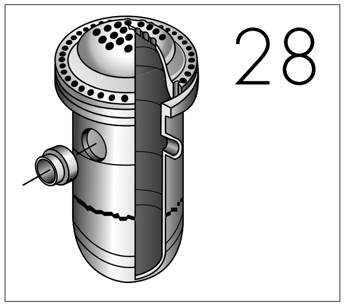
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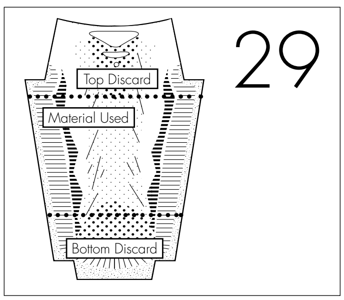
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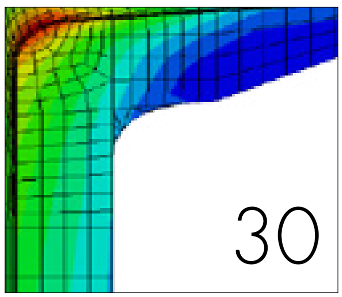
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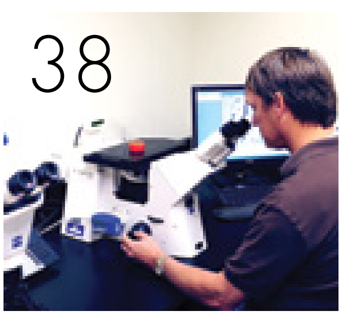
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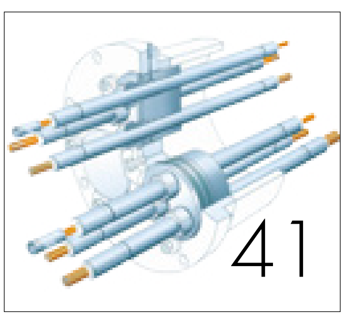
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FROM WIND TO ELECTRICITY

By: CECI WILSON, Ph.D., P.E.
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Capturing energy from wind and distributing it as electricity has become a reality. Rooted in small windmills for farms, utility-scale wind farms are developing at a fast pace evidenced by the new landscapes in Texas and Iowa with tall white structures with rotating blades on top of them. Several sources have reported that 4.7% of all U.S generated electricity was supplied by wind energy in 2015, and projections show that it will not stop here. AWEA (American Wind Energy Association) reported that 2016 saw an incremental 15% growth per quarter on wind project development and construction, which will add 20GW of generation capacity to the already existing 75GW capacity in the U.S. What drives this fast pace growth and what challenges lay ahead for what can be considered an industry in its infancy?

WIND ENERGY DRIVERS

The pursuit of "green", "clean" and renewable resources for electricity generation are definitely a big driver for wind energy. So much so that 19 U.S. states have adopted Renewable Portfolio Standards (RPS) requiring utilities to supply a percentage of electricity to come from renewable resources[1]. An example is California with an RPS of 50% by 2030 or Hawaii with 100% by 2045. The RPS opens the market for wind (among other renewables) utility purchasers.

To make wind energy more cost appealing, a renewable energy Production Tax Credit (PTC) was created under the Energy Policy act of 1992 that allows for an income tax credit of 2.3 cents per kilowatt-hour produced. The PTC was a temporary credit that was to be phased out within a specified number of years. It has driven the development of wind projects such as the boom in 2012 and 2015. In December 2015, the PTC was extended for four years which has driven increased investments in new wind projects for the near future.

Added to these drivers is the fact that wind's Levelized Cost of Electricity (LCOE) is projected in 2020 to be around $74/MWh placing it in direct competition with natural gas combined cycle (see Figure 1 from U.S. Energy Information Administration). This LCOE has made wind energy very attractive for non-utility purchasers such as large companies that own large distribution centers. In 2016, 33% of total capacity in development was contracted to non-utility purchasers[2].

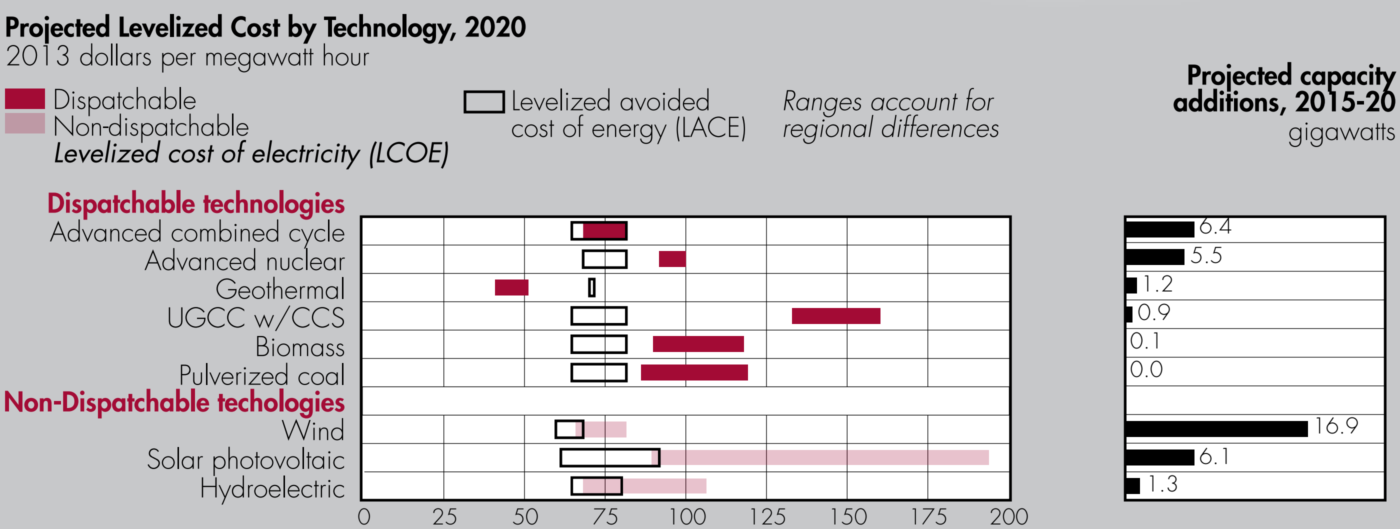

Figure 1. Levelized cost of electricity (LCOE) comparison and projections for various generation technologies. Source: U.S. Energy Information Administration

In summary, demand for wind energy is increasing and new and existing projects will have to adapt to meet market expectations.

WIND ENERGY CHALLENGES

Building a wind project is not a trivial task. There are many steps in development that can delay or stop a wind project such as land permitting, environmental siting and local government policies/regulations. Often the biggest challenge is being interconnected to the grid. Some sites that are optimal for wind projects are in isolated rural areas, where specific substations and introduction to the grid are very challenging, with long lead times and great expense.

Wind itself can be a challenge to predict or measure for specific areas when planning a project. Wind turbines work across a specific range of wind speeds. If too fast, the wind turbine will trip offline. If too slow, there is no energy to extract. In some locations wind conditions are favorable at night when there is little demand for electricity. All of this intermittent energy production can create disruptions. Energy storage, such as batteries, would solve the variability issues, but the technology for this scale is still in development.

Last but not least is the cost of operations and maintenance. Wind Turbine O&M has been reported to account for 25-30% of a turbine's life cycle cost. A current challenge is keeping turbines running while minimizing maintenance costs. Presently, there are approximately 40,000 wind turbines online in the U.S. at capacities greater than 1 MW. The fleet's age varies with approximately 20% of the fleet at 10-16 years of age, 60% at 5-10 years and 20% under 5 years. This means that none of the modern utility scale wind turbines have experienced their 20-year design lifetime and historical O&M data is scarce. Hence, as wind turbines age the industry is learning what are the most common failure modes and their associated rates, and the appropriate maintenance strategies needed to address them.

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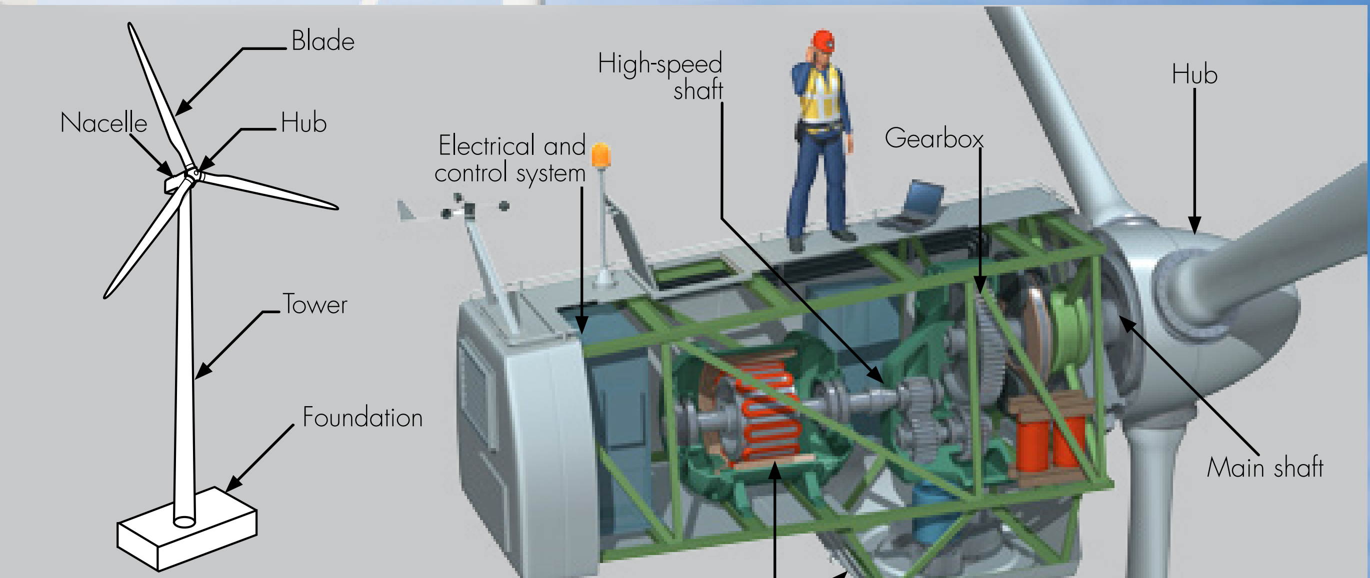

Figure 2. Wind Turbine components and Nacelle sub-components.

To date statistics show more turbine failures and higher maintenance costs than expected, which has caused this to become a major concern to a lot of owners and operators. A wind turbine consists of various components as shown in Figure 2. In the last few years, blades, gearboxes and generators have been reported to have the highest rate of failures and/or repair/replacement downtimes (See Figure 3).

- Gearbox and drive train failures were experienced from the earliest turbine designs at high failure rates. These have been the focus of maintenance improvements including, adding condition-based maintenance systems and implementing appropriate inspection intervals. According to NREL[3] the leading failure mechanism is axial cracking in the high or intermediate shaft bearings.
- Blades failing within years 1 and 2 have been attributed to manufacturing defects or transportation damage[3]. While lightening damage is regarded as one of the main causes for blade failures, many other causes exist such as, adhesive bonding issues, trailing edge separation, and de-bonded protective coatings. Unfortunately, condition-based maintenance is still challenging for blades and maintenance data comes from limited up-tower inspections.
- In Shipurkar et al study[4] of wind turbine generator failures it was found that stator and bearing damage were responsible for approximately 75% of the generator failures.

As a young industry, wind farm owners, operators and maintenance service providers do not have a lot of historical data and past experiences to learn from. At Structural Integrity we have applied our expertise with failure analysis, damage evaluations and NDE solutions to a number of wind turbine components. We have recently expanded our capabilities to include composite materials which will prove invaluable as blade damage assessments become a vital part of wind life management.

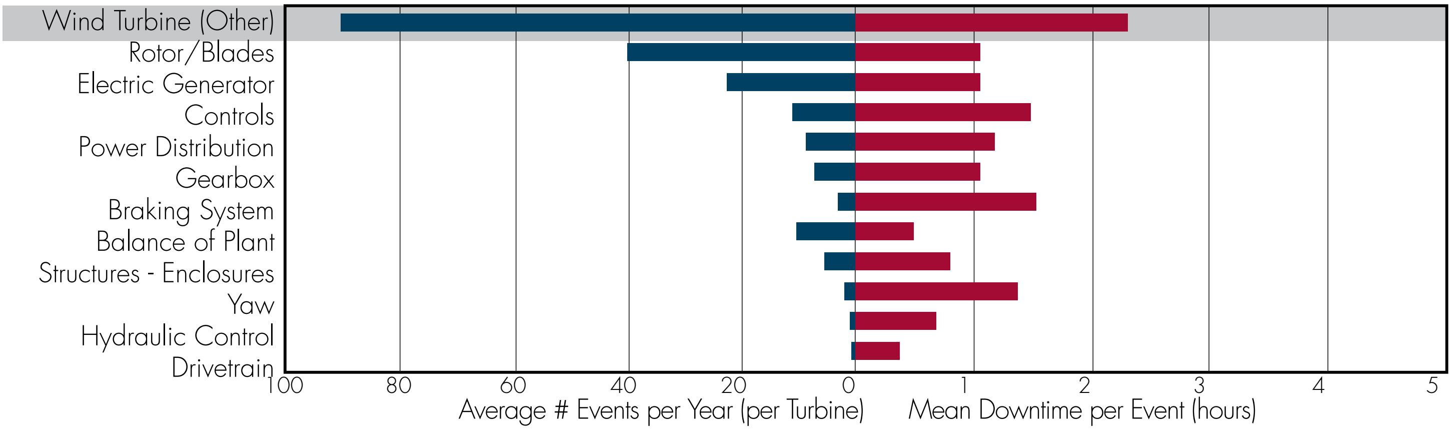

Figure 3. Example of wind turbine component failure rate and downtime. Source: NREL/PR-5000-59111

[1]: American Wind Energy Association (2016 RPS and Wind Market Reports)
[2]: U.S Energy Information Association
[3]: National Renewable Energy Laboratory, Report on wind turbine reliability – A survey of various databases. June 2013 (NREL/PR-5000-59111)
[4] : Shipurkar, U., Ma, K., Polinder H., Blaabjerg, F. and Ferreira J.A. A review of failure mechanisms in wind turbine generator systems. 2011 Electrical Insulation Conference (EIC). IEEE, Jun. 2011, pp. 392–397.

EVALUATION FOR CONTINUED SERVICE OF A FAC DEGRADED COMPONENT

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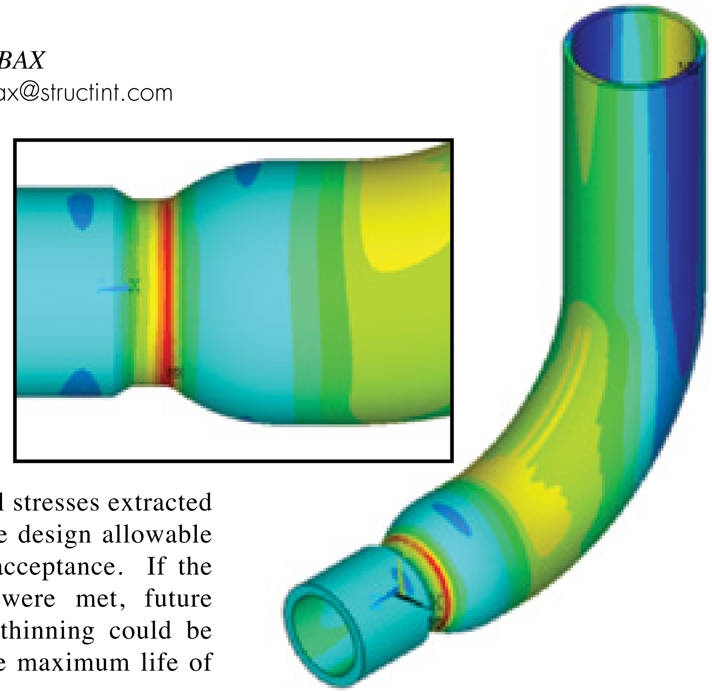
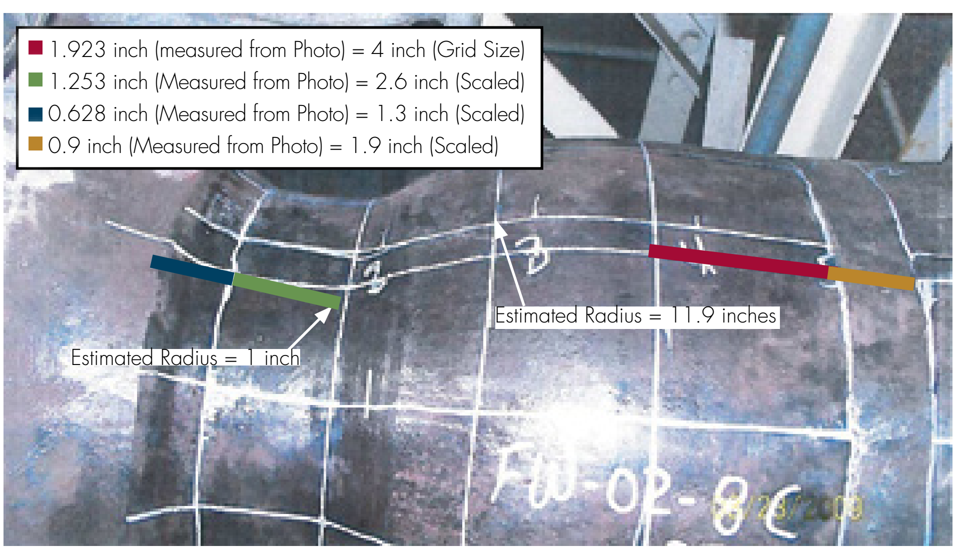
Recently, ultrasonic inspections at a domestic PWR identified localized wall thinning due to Flow Accelerated Corrosion (FAC) in a their feedwater piping system. Specifically, in a carbon steel 18 x 12-inch expander located in the auxiliary boiler building that is non-safety related. Based on a fitness-for-service analysis, the projected wall thinning will be below the design minimum wall thickness prior to the next refueling outage. Structural Integrity was contacted in order to help the station reduce identified conservatisms through a more sophisticated analysis.

Using detailed inspection data from the site, we developed a finite element model of the degraded expander for evaluation. The model reflected the actual profile of the remaining expander wall thickness and allowed for structural credit to be taken for all remaining material as opposed to assuming uniform thinning. The finite element model was then further thinned, using corrosion rate data from the plant, such that the future condition of the expander at the next refueling outage could be analyzed. Design loading could then be applied to the model and directional stresses extracted for comparison to the design allowable stress to determine acceptance. If the acceptance criteria were met, future operating cycles of thinning could be applied to predict the maximum life of the expander.



Taking advantage of a higher design allowable stress in more recent ASME Codes (between 1999 and 2000 the ASME changed the safety factor associated with material allowable stress from 4 to 3.5), we prepared a code reconciliation to justify the use of the 14% higher allowable stress. The Code of Construction for the feedwater piping at this PWR is B31.1. Since B31.1 does not provide reconciliation guidance to newer codes, guidance was taken from ASME Section XI, IWA-4200.



By performing a stress evaluation using the developed finite element model and comparing the stress results to the higher design allowable stress, it was determined the expander wall thickness would not violate the design minimum wall thickness by the next refueling outage. In fact, additional operating cycles of thinning were applied to the model and the expander was found to be acceptable for at least 18 more years of future operation if the corrosion rates remain constant.

USING PORTABLE MATERIAL PROPERTY DEVICES FOR PIPE GRADE DETERMINATION

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Proposed U.S. gas pipeline industry safety regulation changes were announced in 2016, many of which were prompted by the U.S. Department of Transportation (DOT) incident findings over the last decade. Of special note is the proposed new requirement in 49 CFR Part 192.607 to determine and verify the physical characteristics of any installed line pipe, valve, flange and component where material records are not available. To satisfy this requirement, Reliable, Traceable, Verifiable and Complete (RTVC) records will be needed in High Consequence Areas (HCA), Class 3 or Class 4 locations.

The industry has been developing in-situ techniques to measure pipe properties in lieu of other destructive approaches (e.g., cut-outs and tensile testing) for the last 20 years. Part 192.607(c) has proposed that any non-destructive method used to determine strength be able to produce results accurate within 10% of the actual value with 95% confidence. Furthermore, the operator must use methods, tools, procedures and techniques that have been independently validated by subject matter experts in metallurgy and fracture mechanics.

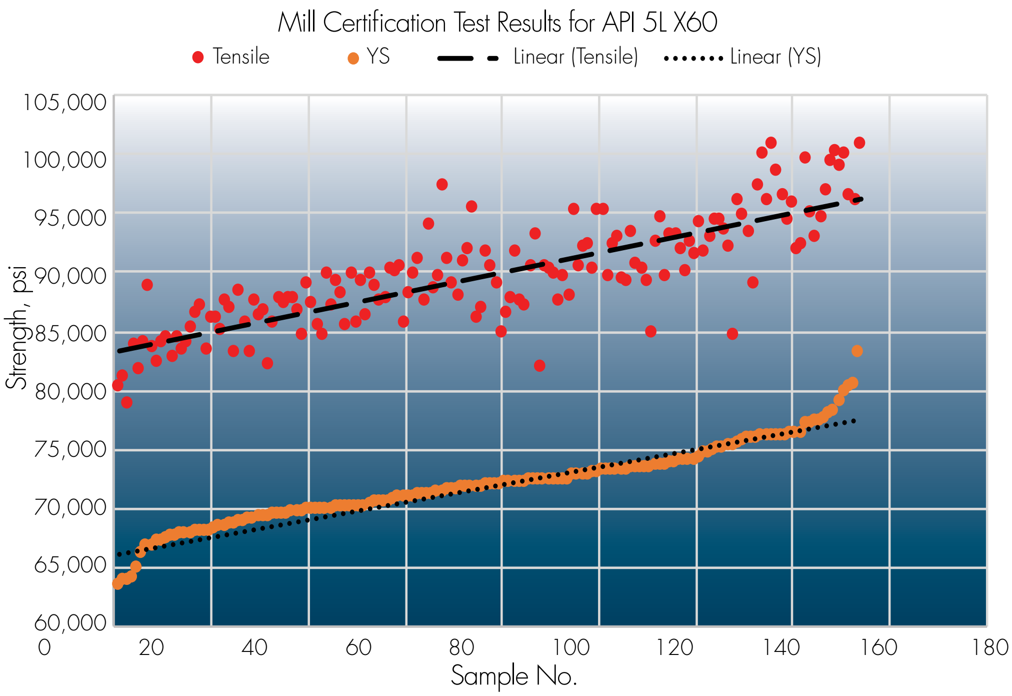
The approaches being pursued to date for assessing properties include: hardness testing (e.g., Brinell, Leeb) combined with metallography and chemical characterization techniques; instrumented indentation (e.g., progressive indentation and unloading); as well as frictional sliding techniques. Most of the more advanced approaches has been commercially developed, so their theory and interpretation basis is proprietary. Very little testing data have been made available to support an independent analysis of each supplier's performance claims. This places the performance specification burden of accuracy and confidence on the end user.

Hardness testing is essentially an empirical measurement of a material's resistance to plastic deformation; the measured hardness is related to the size or depth of an impression made at a defined load. But fundamental material properties, such as yield strength, are not directly measured due to the complex stress-strain state involved in the deformation. Despite this complexity, the measured hardness is clearly related to the elastic-plastic properties of the material, and the hardness value usually correlates reasonably well with strength, particularly within a given material class. Somewhat counter-intuitively, the correlation is usually better for ultimate tensile

strength than yield strength, and standard correlations between tensile strength and hardness for various alloy systems are given in ASTM and CEN specifications.

Joint Industry Development efforts have made progress toward understanding the correlation between hardness and mechanical properties. GRI, PRCI and private industry projects have all applied research dollars toward this pursuit. Promising new techniques include: Progressive indentation; Frictional sliding principles, and the recent repurposing of Inline Inspection (ILI) signal responses for classifying pipe joints with similar bulk magnetic properties.

A formal, written material testing procedure can be a beneficial tool to increasing the performance and reliability of these nondestructive tests. An effective procedure defines roles of responsible personnel, describes the process for determining the number of tests required to verify the materialS, describes the sample collection process and field data collection process, standardizes documentation, and provides guidelines for determining the test locations. The use of record data (as-built drawings, bills of materials, etc.) and its interaction with test results must be considered carefully. Application of a rigorous procedure that provides a clear method and criteria can improve consistency and traceability in material testing.



Acceptance criteria for line pipe per property tested should also be developed based on acceptable values for the segment properties based on record data. Measurement uncertainty in the test equipment should be considered when making this determination. Factors to consider include, but are not limited to:

- Chemical Analysis - weighting percentage per element meets acceptance criteria for chemical composition in API 5L for grade;
- Yield Strength and Ultimate Tensile Strength minimum values of tests are greater than or equal to API 5L specified minimums for grade;
- Wall Thickness average (considering diameter of pipe under test) and diameter are within tolerance in API 5L;
- Seam Type verified by test is the same as seam type in record documentation

Promising new nondestructive testing approaches are emerging that leverage variations in hardness testing methodologies. Our experience suggests that new procedures will be required to most effectively use these technologies to minimize the inadvertent influence of local material conditions and other testing parameters.

As with any new technology, each approach will require a great level of validation testing, data analysis and rigor in application to help make nondestructive material verification a routine, reliable, and accepted tool.

THROUGH WALL SIZING OF CIRCUMFERENTIAL CRACKING IN RIFLED WATER WALL TUBING

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BACKGROUND

Due to thermal "downshocks" and "upshocks" in the boiler, associated thermal expansions and contractions can lead to axial stresses that cause thermal fatigue cracks on the fireside of water wall tubing. This condition is often exacerbated by corrosion products near the crack tips that accelerate crack growth. Because of these phenomenon, through-wall circumferential cracking has occurred in the furnace wall tubes of both subcritical and supercritical boilers. While this type of cracking can be easily detected by visual inspection, managing the cracking requires the proper tools to accurately monitor the through wall extent and determine growth rates. The best means for monitoring these cracks is with Nondestructive Examination (NDE) methods. As illustrated here, not any NDE method will succeed in overcoming the numerous challenges in sizing this type of cracking in the boiler. We have successfully overcome these challenges by performing a combination of Eddy Current Testing (ECT) and Phased Array Ultrasonic Testing (PAUT) to locate and size the deepest circumferential cracks in boiler tubes. However, even proven techniques must be updated periodically to address new challenges, and, as described here, a recent experience with rifled boiler tubes required a technique modification to reliably size the cracking.

Figure 1. Cracking Severity

Figure 2. Water Wall inside boiler

PROBLEM

As shown in Figure 1, the visual severity of fire side circumferential cracking can vary considerable; from numerous closely spaced cracks numbering 20-30 cracks per inch, to sparse cracking that numbers only 2-3 per inch. In addition to the numerous and closely spaced cracking, additional challenges for NDE include hundreds of tubes with damage and many linear feet of tubing to examine (Figure 2). As a result, Structural Integrity developed a two-stage approach that has proven effective in identifying and sizing the deepest cracks; ECT to screen for cracks greater than 0.050" deep and PAUT to size those greater than 0.050" cracks. The advantage of this approach is that ECT is fast and requires no couplant so it provides a means to rapidly screen numerous feet of tubing to isolate the most severe (deepest) cracking. This approach typically leaves a much-reduced area to perform detailed sizing using PAUT. Sizing with PAUT is typically performed by bouncing or skipping sound waves off the tube bore as shown in Figure 3. While this works effectively for smooth bore tubing, rifle bore tubing creates another unique challenge, as illustrated in Figure 4. The existence of rifle bore tubing in the boiler at a client site provided the impetus for reevaluating the current PAUT approach to determine the feasibility of sizing cracks in this tubing.

INVESTIGATION

To evaluate the ultrasonic effectiveness for rifled tubing, EDM notches of depths ranging from 0.025" to 0.150" were machined into field removed tubes provided by the client. Accurate through wall sizing of cracks is best performed using the crack tip diffraction method, that is, resolving the small amplitude response from the crack tip and measuring from the tip to the component surface (corner trap) to determine the through wall height. This is illustrated in Figure 5. PAUT has many benefits when it comes to characterizing defects in power plant components and one of them is the "true depth" sector scan which presents a real time image that is corrected for distance and depth in the material. When implemented correctly, PAUT can provide the through wall size directly from the 2-dimensional sector scan as depicted in Figure 5 for a 0.100" deep notch in a rifled boiler tube.

Historically, this application was performed using a small footprint probe that did not require contouring the wedge of the probe to couple to the radius of the tube. These probes, which had been successful on smooth bore applications, are easy to manipulate and skew on the tube surface. However, because of their small aperture (total element surface area) they are limited in focusing ability. As previously mentioned, most sizing must be performed on the second leg of sound to ensure the sound beam reaches the crack and crack tip. The focal range of these small aperture probes is shorter than the metal path required for focused sound to reach the cracked Outside Diameter (OD) surface of the tube. To further complicate the examination, the geometry of the Inside Diameter (ID) surface of rifled bore tube caused the sound beams to bounce off the ID bore at irregular angles, as seen in Figure 4. Therefore, not only were the small aperture probes not able to focus sound at the depths necessary to reach the cracked OD surface, but the rifled ID bore caused this limited sound field to bounce in multiple directions, thereby only allowing small "windows" of unfocused sound to reach the OD crack area.

To improve the PAUT sizing technique, larger aperture probes were evaluated using a combination of software simulation and laboratory testing to prove that the longer focal zone could effectively reach the cracked OD surface after bouncing off the ID surface. This testing confirmed the larger aperture provided a greater amount of sound energy and the geometry of the ID bore surface of a rifled bore tube would have less negative impact on the amount of sound energy reflected to the cracked OD surface.

Laboratory testing confirmed, at best, the smaller aperture probes could only resolve notch tips at the shortest possible metal path (i.e. the lowest angles), but did not have sufficient aperture to detect tip signals at higher metal path distances (i.e., higher angles). While using small aperture probes and low angles worked effectively for smooth bore tubing, the limited "windows" to skip sound in rifled tubing combined with the limited effective angles and short range of the smaller aperture probes resulted in the possibility of missing crack tips and erroneous sizing measurements.

Although the use of a larger aperture probe requires a wedge that must be contoured to fit the curvature of the tube outside diameter, this combination of larger probe and contoured wedge provides

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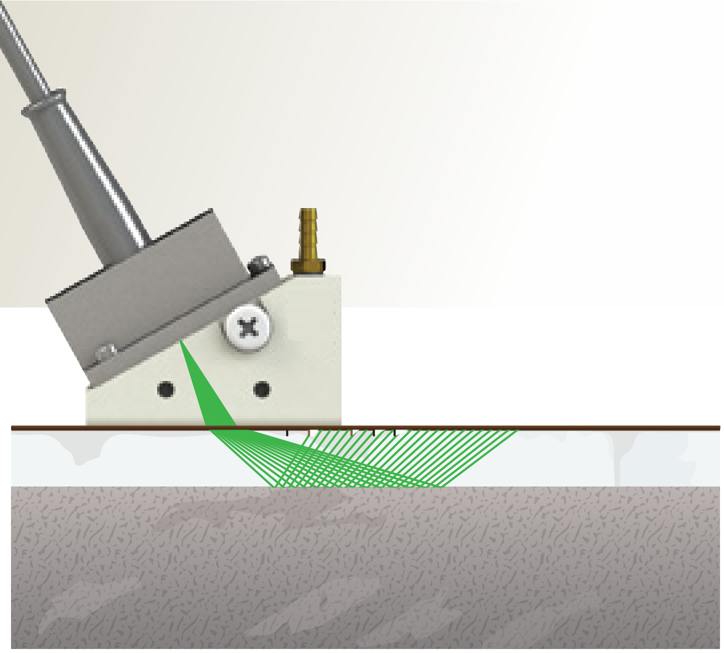


Figure 3. PAUT Crack Sizing in Smooth Bore Tubing

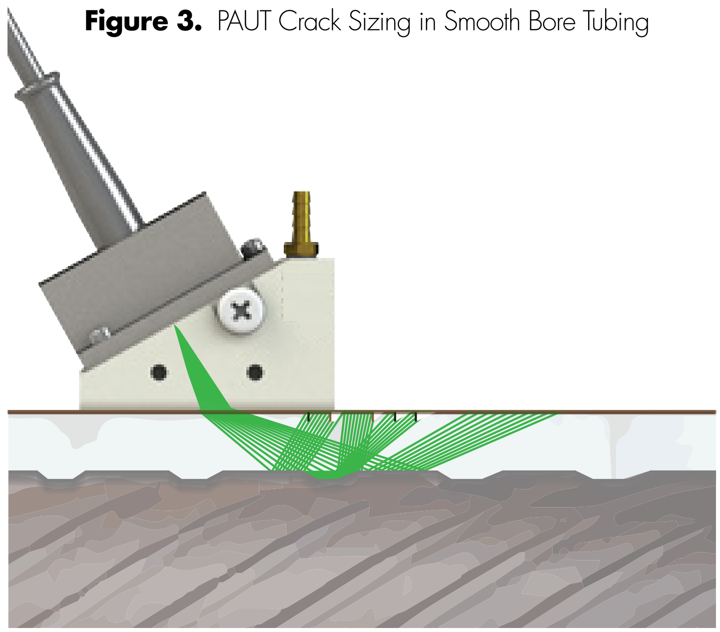


Figure 4. PAUT Crack Sizing in Rifled Bore Tubing

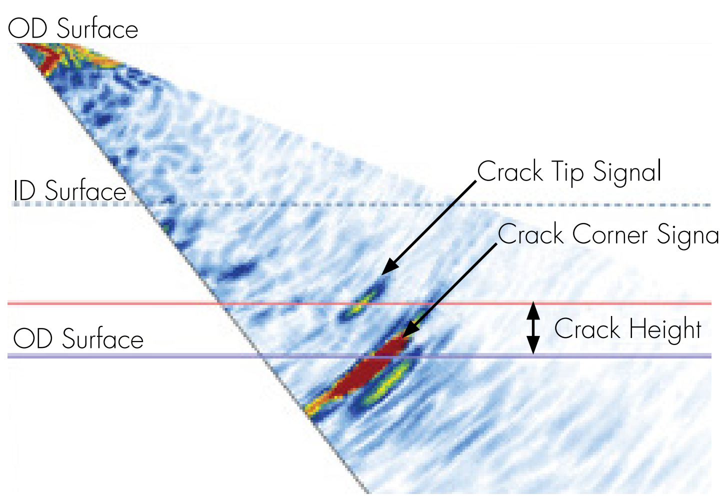


Figure 5. PAUT Through Wall Sizing using Crack Tip Diffraction

THROUGH WALL SIZING... CONTINUED

improved opportunities to observe the crack tip over a greater range of angles which enhances the ability to size cracks. As an example, on a field removed tube using the larger aperture probe, the tip of a notch imbedded in a group of shallow cracks is readily detectable over an angular range of 35° to over 60° in the sector scan with indications that travel for over 1/2-inch as the probe is indexed axially (Figure 6). For the smaller probes, effective angular range was typically 35° to 45° with potential axial travel less than 1/4-inch and was truncated by the rifling which greatly reduced the chances of locating and resolving the crack tip.

CONCLUSIONS

Based on software simulations and laboratory testing on field removed samples with known and unknown defects, it was concluded sizing cracks in rifled tubing is feasible with some adjustments to our existing techniques and approach. While ECT screening is unaffected by the rifled tubing, for PAUT, effective techniques require probes with extended focal ranges and the use of contoured wedges to couple to the tube. Since tube types and sizes can vary considerably from plant to plant, it is a good idea to have representative tubing to use for calibration. When properly applied, NDE can provide a huge benefit for managing cracking in boiler tubing and other components.

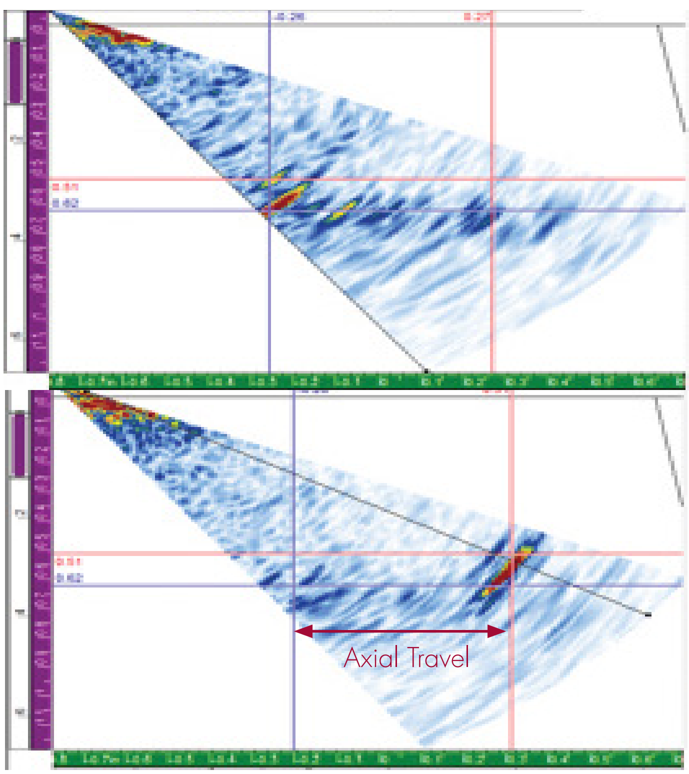
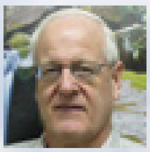


Figure 6. Response from Notch in Field Removed tube from 35° (TOP) to 60° (BOTTOM) using larger aperture probe.

Part 3 – Analytical Tools to Address Cycle Chemistry Influenced Failure and Damage Mechanisms



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1.0 INTRODUCTION

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. As this is a very large and important area for fossil and combined cycle plants, Structural Integrity decided to describe it in three parts. The first part, (N&V 2016, Volume 40, www.structint.com/40-News-and-Views/#book/11) introduced 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 / HRSG evaporator water, and steam. These optimum chemistry treatments were also described in the first article. The second part (N&V 2016, Volume 41, www.structint.com/41-News-and-Views/#book/29), delineated the damage and failure mechanisms influenced by not operating with these optimum treatments which results in the protective oxides breaking down. This third article describes the key analytical tools which have been developed by Structural Integrity and used in over 200 plant assessments worldwide to identify whether these failure and damage mechanisms will occur by identifying the number of Repeat Cycle Chemistry Situations (RCCS). These same tools are used to optimize fossil and combined cycle chemistry control to proactively prevent failure and damage.

2.0 DEVELOPING AN UNDERSTANDING OF CYCLE CHEMISTRY INFLUENCED FAILURE/DAMAGE IN FOSSIL AND COMBINED CYCLE/HRSG PLANTS USING REPEAT CYCLE CHEMISTRY SITUATIONS (RCCS)

As described in the first article, the understanding of the cycle chemistry influenced failure and damage mechanisms in the steam/water circuits of conventional fossil and combined cycle/HRSGs is very advanced, and has been known and documented for more than 30 years. Despite this, and as described in the second article, chemistry influenced damage and the associated availability losses due to deficient chemistry practices are often enormous. Damage and component failure incidents persist, in both fossil units and combined cycle units, and in the case of Flow-Accelerated Corrosion (FAC) can create a safety problem for plant operating staff. It is thus very clear that the approaches taken by organizations operating fossil and combined cycle plants to prevent such damage are frequently unsuccessful. Similarly, fossil industry usage of the response methodology by which chemistry-related damage events are reacted to (identification of the mechanism, assessment of the root cause, and implementation of actions to stop the mechanism) is often ineffective.

Analysis by Structural Integrity in 2008 of past cycle chemistry assessments and damage/failure investigations of over 100 organizations worldwide at that time lead to a very interesting new concept to prevent damage/failure proactively. This involves identifying Repeat Cycle Chemistry Situations (RCCS). The RCCS which can be regarded as the basics of cycle chemistry, are allowed to continue by the chemistry or operating staff or are imposed on the plant/organization as a consequence of inadequate management support for cycle chemistry.

Continued on next page

CYCLE CHEMISTRY KEY TO FOSSIL AND COMBINED CYCLE/HRSG PLANT RELIABILITY CONTINUED

The first sub-section (2.1) introduces the reader to RCCS while the second (2.2) provides information on the application of the RCCS analysis to 185 plants worldwide since 2008. This analysis in total from over 280 plants worldwide confirms that the process can be used proactively to identify cycle chemistry deficiencies, which if not addressed will lead to future failure/damage of the types delineated in the last section (3.0). The RCCS analysis is also used in root cause analysis to identify the cycle chemistry features responsible and which can be addressed through Action Planning.

2.1 DEVELOPMENT OF REPEAT CYCLE CHEMISTRY SITUATIONS (RCCS)

The analysis which we did in 2008 identified two key features which related to why and how cycle chemistry influenced failure/damage occurred in fossil and combined cycle/HRSG plants. From the mechanism aspect, the first shows that cycle chemistry influenced failure/damage involves the breakdown of the protective oxide which grows on all fluid-touched surfaces. This could involve cracking, fluxing, dissolving, and solubilizing of the oxide layers as well as transportation and deposition of corrosion products (oxides) on the heat transfer surfaces. From the viewpoint of organizational or management aspects of the cycle chemistry and its control, it became clear that every cycle chemistry failure/damage incident can be related backwards in time to multiples of RCCS which were not recognized or properly addressed and allowed to repeat or continue. In some cases, the chemistry staff had not recognized the importance of the situation and allowed it to continue. In other cases, the chemistry staff recognized the importance, but was not successful in convincing the management (either plant or executive) that action was required to eliminate the RCCS. In many cases the management has delayed action or has not provided the necessary funds to resolve the situation. In doing this type of retroactive analysis, it very quickly became obvious that plants/organizations can get away with having one or two RCCS, but once this number increases then failure/damage was a certainty.

In 2008, the following ten RCCS were identified which were very commonly associated with preventable cycle chemistry related damage in fossil and combined cycle plants:

- High levels of corrosion products
- High boiler/HP evaporator deposition
- Non-optimum chemical cleaning
- Contaminant ingress (with no reaction by the operators)
- Drum carryover
- High level of air in-leakage
- Lack of shutdown protection
- Inadequate on-line alarmed instrumentation
- Not challenging the status quo
- No Action Plans for any of these repeat situations

After using the RCCS analysis at 185 plants worldwide since 2008, the categories have remained the same but it has become clear that there are multiple sub-categories for each.

To assist the readers in understanding the concept of RCCS and whether they exist in their plants the following subsections provide a few notes on some of the most important categories. Some examples of a few case studies are provided later to further illustrate this concept.

This RCCS analysis is very powerful in assisting with root cause analysis, in identifying where cycle chemistry failure/damage will occur in the future, and where improvements should be made. The compiled statistics of RCCS have also been used internationally to identify where international research and guidance is necessary.

Corrosion Products. Categories include: corrosion product levels are not known or monitored by plant staff; the levels are too high and above international guideline values (examples: could be >1ppb total iron at the economizer inlet for supercritical units on Oxygenated Treatment (OT), or > 2 ppb in the feedwater of sub-critical fossil plants or combined cycle/HRSG plants); inadequate and/or insufficient locations being monitored; sampling conducted at the same time /shift each time; using techniques with incorrect detection limit; a most common feature is monitoring the soluble part only by not digesting the sample in a laboratory before using a spectrophotomer. A key easy-to-observe verification aspect of this RCCS is black deposits in the steam and water sampling troughs for units on AVT(O), or red deposits for units on AVT(R).

Boiler/Evaporator Deposits.
Categories include: boiler waterwall

or HRSG HP evaporator samples have not been taken; there is no knowledge of deposits and deposition rate; samples have been taken but not analyzed comprehensively; deposits excessive and exceed criteria to chemical clean; in HRSGs the HP evaporator deposits are not linked with chemistry in the lower pressure circuits or to the levels of transported total iron; the boiler/evaporator has been sampled and needs cleaning but management delayed or cancelled the actual clean.

Drum Carryover. Categories include: not conducted since commissioning; not conducted even on units with steam turbine Phase Transition Zone (PTZ) problems; not aware of simple process to measure carryover; saturated steam samples not working or non-existent; samples taken are not isokinetic.

Continuous On-line Cycle Chemistry Instrumentation. Categories include: installed and operating instruments is at a low % compared to International Standard (a normal level is between 58 and 65%); too many instuments out of service, not maintained or calibrated; instruments are not alarmed for operators and many are shared by multiple locations and not / never switched; plant relies on grab samples to control plant (1 – 3 times per day/shift); the instrumentation most often missing is CACE (cation conductivity) and sodium on main or HP steam and conductivity (specific conductivity) on makeup line to condenser.

Challenging the Status Quo. Categories include: no change in chemistry since commissioning; using incorrect or outdated guidelines; continuing to use reducing agents in combined cycle/HRSGs and in fossil plants with all-ferrous feedwater systems, and thus risking or experiencing single-phase FAC; continuing to use the wrong phosphate treatment (usually not using only tri-sodium phosphate); not having a chemistry manual for the unit, plant or organization; incorrect addition point for chemicals (most often reducing agent with AVT(R)); not questioning use of proprietary chemical additions (phosphate blends, amines, FFP) and therefore not knowing the composition of chemicals added to the unit / plant; not determining through monitoring the optimum feedwater pH to prevent/control two-phase FAC.

Shutdown/Layup Protection. Categories include: Unit/plant has no equipment for providing shutdown protection for boiler, HRSG or feedwater heaters; equipment present but not used or inoperable / not maintained; poor / no operator procedures; only partial protection applied (boiler/HRSG vs, feedwater); no dehumidified air (DHA) provided for the steam turbine shutdowns.

Contaminant Ingress. Categories include: no assessment of risk; inadequate instrumentation and alarms (especially for seawater cooled plants); operators allow exceedances of control and shutdown levels; chemists and/or operators compromise limits to plant ability (make high readings acceptable), or make up (invent) normal and action levels which have no technical relevance; no comprehensive procedures to deal with contaminant ingress.

2.2 USING RCCS TO IDENTIFY DEFICIENCIES IN CYCLE CHEMISTRY CONTROL

Between 2008 and 2016 Structural Integrity has applied the analysis of RCCS during 185 plant assessments. 117 of these were at fossil plants and 68 at combined cycle plants involving HRSGs from 18 manufacturers. The work involved a large range of assessments which included: boiler and HRSGs tube failure mechanism and root cause assessments; fossil and combined cycle FAC and Air-Cooled Condenser (ACC) assessments; cycle chemistry assessments and chemistry optimization; cycle chemistry treatment conversions to OT and Phosphate Treatment (PT); Plant Transmitter Zone (PTZ) blade and disk failure/damage root cause analyses in fossil and combined cycle plants; copper deposition on fossil plant HP turbines; development of shutdown/layup and preservation procedures for all types of plants; and combined cycle plants with desalination equipment interface problems.

Continued on next page

CYCLE CHEMISTRY KEY TO FOSSIL AND COMBINED CYCLE/HRSG PLANT RELIABILITY CONTINUED

RCCS Categories	In 117 Conventional Fossil Plants	In 68 Combined Cycle / HRSG Plants
Corrosion Products	90	92
Conventional Fossil Waterwall / HRSG Evaporator Deposition	45	62
Chemical Cleaning	15	< 10
Contaminant Ingress	16	< 10
Drum Carryover	80	88
Air In-leakage	40	< 10
Shutdown Protection	77 (& 92*)	65 (& 92*)
On-line Alarmed Instrumentation	80	92
Not Challenging the Status Quo	81	77
No Action Plans	N/A	N/A

* Use of dehumidified air (DHA) on steam turbine during shutdown

Table 1. Analysis of Repeat Cycle Chemistry Situations (RCCS) in Conventional Fossil and Combined Cycle/HRSG Plants. (Notes: The numbers in the table represent the percentage of plants where the RCCS was identified. Action Plans were developed for each RCCS at each plant).

Table 1 shows the data for these fossil and combined cycle/HRSG plants. Table 1 clearly shows a ranking order of RCCSs with monitoring corrosion products and on-line instrumentation being the most often cycle chemistry processes not being applied properly. These are followed by not challenging the status quo and measuring carryover. General shutdown procedures for plants is relatively high on the list with the sub category of applying / using DHA most often missing. It is expected that the application of Film Forming Products (FFP) will over the next 5-10 years start to provide this shutdown protection.

3.0 CASE STUDIES

This section provides four case studies as examples of applying the RCCS methodology to make assessments on failure / damage and its proactive use to assist fossil and combined cycle / HRSG plants in determining if failure / damage will occur in the future.

3.1 CASE STUDIES 1 AND 2: DAMAGE / FAILURE IN THE PHASE TRANSITION ZONE (PTZ) OF THE STEAM TURBINE IN COMBINED CYCLE / HRSG PLANTS

Protection of steam turbines from chemistry influenced damage as indicated in the second article (N&V 2016, Volume 41) has long been recognized as an integral key aspect of effective cycle chemistry programs for fossil and combined cycle / HRSG plants. Equipment manufacturers and research organizations have performed extensive investigations of damage mechanisms and determined that most are related to the chemistry, both during operation and when the unit is out of service. Experience has shown that many organizations continue to experience contamination of the steam, leading to various consequences. In some instances, a developing problem is identified during service through monitoring of carryover. But in most cases, the existence of steam purity issues only becomes apparent when blade or disk cracking is observed during an inspection conducted as a scheduled maintenance activity or as a consequence of a failure incident. This sub-section includes two combined cycle / HRSG Case Studies which illustrate a pattern observed worldwide in conventional fossil and combined cycle plants. The first case was a failure incident where the last stage blades were found cracked during a maintenance inspection. The second in a plant 8,000 km from the first was not a failure situation but part of a combined cycle / HRSG plant cycle chemistry assessment where the analysis of the RCCS was almost identical to the first case study, so suggested proactively that future failure was a possibility.

Case Study 1. This L-0 blade cracking occurred in a 700MW 2x1 combined cycle / HRSG plant after about 90,000 operating hours. The cracking emanated from pits on the blade surface. The plant had two gas turbines and a steam turbine (HP/IP and LP), and triple-pressure HRSGs with HP drum pressure of ~10.3 MPa (1500psi). The condenser had titanium tubes which had experienced numerous condenser leaks of the brackish cooling water. The cycle chemistry condensate/feedwater treatment included a proprietary amine blend (ETA / MPA) and a reducing agent (Carbohydrazide), and a proprietary phosphate blend be added to all three drums.

During the root cause analysis the following seven RCCS were identified with the last five being directly related to the PTZ cracking:

- Total iron corrosion products not measured at any location around the cycle.
- No HP evaporator tubes had been removed to assess internal deposits.
- Instrumentation at low level compared to international standards. The level of instrumentation (about 50%) was inadequate for identifying contamination quickly. There was no sodium at the condensate pump discharge or in HP superheated steam (HPSH), pH in feedwater, no Conductivity After Cation Exchange (CACE) in steam, and no combination of CACE/pH in the HP drums.
- Carryover had not been measured. Unknown levels of carryover into steam as the operators / chemists had failed to monitor carryover on a regular basis and during contamination events exceeding the shutdown limit suggesting that steam contamination levels had been higher than the plant guideline limits on multiple occasions.
- Shutdown protection had not been not applied. There was inadequate shutdown protection for the plant and no DHA applied to the LP steam turbine despite frequent contamination events which exceeded the plant shutdown limits.
- Repetitive contaminant ingress. The operators continued to operate when contamination exceeded the unit shutdown limits multiple times, and continued to operate attemperation during these contaminant periods.
- Not challenging the Status Quo. Plant continued to operate with inadequate and out of date chemistry guidance, and kept changing (increasing) the shutdown limit to allow the plant to keep operating. But the operators continued to ignore the shutdown limits and action levels that they had developed. They also continued to use a reducing agent despite the clear international guidance for combined cycle / HRSG plants that this chemical should not be used.

It can easily be seen that this represents a “full house” of RCCS. Singly, by themselves, each RCCS would (probably) not have caused failure / damage, or be viewed as the plant operating out of control. But together, these are commonly the basis of PTZ failures and damage worldwide. The other important observation is that operating with seven RCCS in total is rare but is a clear indicator that some other failure / damage mechanism, such as hydrogen damage, will occur in the future.

Case Study 2. The unit in this assessment was a 650MW 2x1 combined cycle plant with about 93,000 operating hours. The plant had two gas turbines and a steam turbine (HP and IP/LP), and triple-pressure HRSGs with HP drum pressure of ~10.3 MPa (1500psi). The condenser had SeaCure tubes which had experienced condenser leaks of the cooling water (~200 ppb Cl and ~400 ppb SO_4). The cycle chemistry condensate / feedwater treatment included a proprietary amine blend (ETA / MPA). The reducing agent (hydroquinone) had been eliminated a few years before the assessment. A proprietary phosphate blend was added to the HP drums.

During the cycle chemistry / FAC assessment for this plant the following seven RCCSs were identified:

- Total iron corrosion products not measured.
- No HP evaporator tubes removed to assess deposits.
- Instrumentation at low level compared to international standards. The plant had no operational on-line continuous instrumentation and was “controlled” by grab samples.
- Carryover had never been measured.
- Shutdown protection not applied to HRSGs and there was no DHA for the steam turbine.
- Air In-leakage was a continuing problem.
- Status Quo. Plant guidance had not been updated for 6 years.

Continued on next page

By comparing this listing with that from the first case study, the similarities will be noted, and the risks for PTZ cracking and Under-Deposit Corrosion (UDC) were assessed to be high illustrating the power of the RCCS methodology.

3.2 CASE STUDY 3: UNDER-DEPOSIT CORROSION – HYDROGEN DAMAGE

Although the understanding for hydrogen damage was developed over 50 years ago (N&V 2016, Volume 41), hydrogen damage is still prolific in fossil and combined cycle / HRSG plants worldwide. Structural Integrity continues to conduct metallurgical analyses and root cause investigations multiple times each year and continues to identify the same suite of RCCS in the plants that experience this UDC mechanism. In brief, these include:

- Excessive feedwater corrosion products.
- Non-monitored feedwater corrosion products.
- Measuring only soluble corrosion products (no digestion).
- No boiler waterwall or HRSG HP evaporator tubes taken for deposit analysis.
- Excessive deposits on tube ID surfaces.
- Delayed / postponed chemical cleaning.
- Repetitive contamination above Action or Unit Shutdown Levels.
- Contaminant ingress above Shutdown limit.
- No operational or managerial support to shutdown with low pH.
- Inadequate on-line instrumentation below the international standard.
- High level of air in-leakage.
- Not challenging the cycle chemistry status quo including the following categories: the feedwater and boiler water treatments and control limits were not optimal; the specification of chemical treatments and guidance were largely determined by a chemical supplier and thus plant personnel are not fully aware of the active chemical composition of the products they were feeding to the HRSG. No cycle chemistry manual is available for the unit / plant.
- No Action Plans to address any of the above repeat situations. This is because very often the plant staff had accepted these situations as “normal and allowable” under the culture but in other cases were ignored for various reasons.

3.3 CASE STUDY 4: UNDERSTANDING DEPOSITS IN HRSG HP EVAPORATORS

Deposition in HRSG HP evaporators is the precursor for any UDC mechanism as discussed in the second article (N&V 2016, Volume 41), and Table 1 illustrates that not having a comprehensive understanding of these deposits and the deposition rate is key to a number of HRSG failure mechanisms. A new deposit map for HRSG HP evaporator deposits was provided in the second article. The deposit levels also provide an indirect indicator of FAC in lower pressure parts of the HRSG.

4 SUMMARY

The optimum cycle chemistry control of fossil and combined cycle / HRSG plants is of paramount importance in achieving and maintaining the desired availability, reliability and performance. There are a number of key basic features which need to be adopted and addressed to achieve this highest level of operational performance. These have been introduced in the three News and Views articles and involve primarily ensuring that the cycle chemistry drivers for the main damage mechanisms are comprehensively understood and addressed in developing and monitoring the cycle chemistry for fossil and combined cycle / HRSG plants. The previous two articles provided information on the optimum cycle chemistry treatments and control for fossil and combined cycle / HRSG plants as well as an overview of the most important cycle chemistry influenced failure and damage mechanisms that occur in these plants. This third article has introduced a very powerful assessment methodology developed by Structural Integrity to identify proactively if any of these mechanisms will occur in a plant and how they are influenced by the cycle chemistry. It has illustrated how these Repeat Cycle Chemistry Situations (RCCS) can identify how operating outside of optimum treatments and without adequate cycle chemistry control systems (monitoring, instrumentation, analysis, etc) will lead to failure / damage of the plant. A couple of case studies have been included to illustrate how to address and ultimately prevent the major cycle chemistry influenced mechanisms. Specific programs should be developed to ensure that RCCS are not allowed to occur or continue. Addressing each RCCS with an Action Plan to eliminate the situation has been shown to address future failure and damage. The assessment methodology has also been used in many root cause analyses studies.

5 BIBLIOGRAPHY

There are a plethora of international guidelines 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 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). These have been used as the reference materials throughout this article and series and full attribution is given to IAPWS.

SPECIALITY INSTRUMENTATION FOR VIBRATION ANALYSIS/MITIGATION

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Structural Integrity now offers portable multi-channel continuous acquisition systems. Each system is contained in a ruggedized carrying case and pre-loaded with our data acquisition software. With these systems, you can acquire and post process operating vibration data to inform design changes, calculate loads, and evaluate apparent causes. In the past year, our systems have provided the data needed for all types of engineering evaluations, including:

- Evaluation of vibration fatigue as apparent cause of seal cooler line failure during RCP sweeps.
- Evaluate redesign of Moisture Separator-Reheater bellows assembly for FIV and resonance during startup and steady state turbine operation.
- Evaluate thermal cycling/stratification loads following the detection of a flaw to fully define and quantify the cause for crack initiation and growth for an additional fuel cycle.
- Quantify small bore piping support effectiveness following re-design on main steam traps during operation.
- Evaluate ASME OM-3 vibration levels on re-designed seal piping during RCP pump sweeps following FlowServe NX type seal replacement and seal line re-configurations.
- Fully characterize vibration loads for past operability and fracture mechanics evaluation on HPCI lube oil piping

We have increased our instrumentation offerings to enable stations to acquire continuous vibration data during startup testing (as a temporary evolution removed prior to power operation) or for a fuel cycle. Vibration data provides true localized strain, temperature distributions, and modal and operational deflection shapes. These systems allow stations to acquire and evaluate data or have us design testing plans, instrument, evaluate vibration levels and quantify design effectiveness and/or fatigue life.

DEEPSTAR PROJECT SUBSEA INDUSTRY ON THE USE OF API 17TR8 AND ASME SECTION VIII

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As it becomes more fiscally feasible to pursue deepwater drilling, there will likely be a renewed interest in the field of deepwater production. At depths that approach two miles (three kilometers) subsea, and pressures that approach 20 ksi (1380 bar), there are significant challenges that arise. These challenges include ensuring asset reliability in aggressive environments, minimal access for inspection, limited options for repairs, environmental safety considerations and federal oversight. Historically, these challenges have been met using engineering judgement in the absence of a well-defined industry standards. Although there's no replacement for good engineering judgement, in recent years, the API 17 TR8 has been developed and published to address the nuances of deepwater production.

The API 17 TR8 is a technical report intend to guide the design of high-pressure high-temperature (HPHT) subsea equipment. Structural Integrtiy was contracted by DeepStar (CTR 12302) to provide an independent usage of the 17 TR8 to evaluate a representative deepwater component – a 20 ksi 5-inch tee and flange assembly shown in Figure 1.

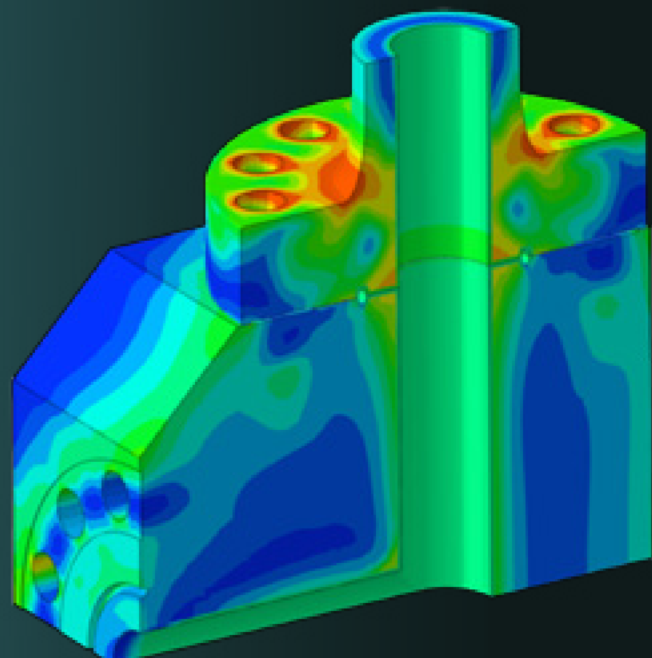
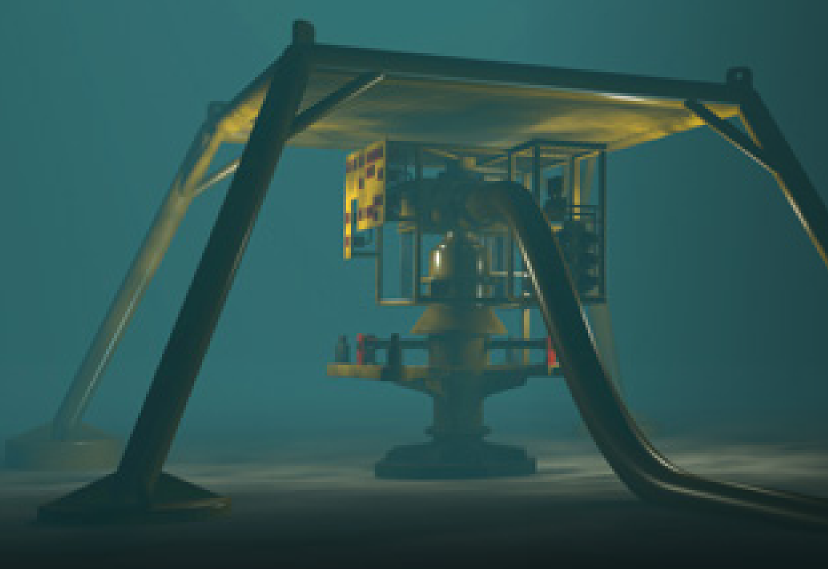


Figure 1. 20 ksi 5 inch Tee and Flange Assembly (Bolts not Shown)

When verifying the design of the flange and tee, three methodologies were used, all of which are acceptable per the design requirements of the 17 TR8:

- ASME VIII-2 Linear Elastic Methodology (VIII-2-LE)
- ASME VIII-2 Elastic Plastic Methodology (VIII-2-EP)
- ASME VIII-3 Elastic Plastic Methodology (VIII-3-EP)



All three methodologies indicated that the 20 ksi operating pressure was sufficient, however there were notable differences in the permissible externally applied loads. As an example, it was found that for the design of this component, VIII-2-LE allowed for the most axial load. There is an important implication here. Depending on the selected methodology, there are multiple allowable working conditions that are acceptable. This is where good engineering judgement comes into play. It's important for the operator of equipment to understand the margins (factors of safety) on all operating components. It's also important to understand if different methodologies are used on different components in the same system to determine margin.

Furthermore, the design verification of the flange and tee required a fatigue assessment based on the expected design cycles. As a worst-case scenario from the three methodologies, the maximum fatigue damage didn't exceed 25% over a 25 year required operating life. If a system were implemented to quantify the cyclic loading in service, there is a possibility to extend the fatigue life because design conditions are typically more severe than operating conditions.

As an additional layer of understanding to the design life, the possibility of existing cracks in the "as-fabricated" state was considered. Based on manufacturing process, non-destructive examination (NDE) technique, and quality assurance protocols, a minimum detection threshold for a crack can be set. Based on this information, it was assumed that the largest possible undetected cracks exists in the tee, flange, pipe and bolts. Cyclic loading can propagate the initial assumed flaw to a critical dimension. Ideally, the operating life is longer than the expected design. Alternatively, the initial flaw size may be found to be unacceptable, implying that there is a possibility that a undetected crack grows to a critical crack size in less than the specified design life. In the latter case, a more refined NDE technique could be developed and used to identify smaller cracks thereby increasing the life estimate.

What constitutes an unacceptable flaw? For starters, an unacceptable flaw is the smallest flaw subjected to the largest expected load that will result in fast fracture. As discussed previously, the smallest flaw is characterized by the resolution of the NDE technique, but what about the largest expected load? The largest expected load can be defined by the survival loading conditions. The survival loading condition is an unplanned event with less than a 0.1% chance of occurring in the total design life of a component. Survival events do not result in failure, but can result in irreversible degradations that can greatly decrease the service life.

Based on a design margin of 1.05 (Global Plastic Collapse Design Margins from API 17 TR8), two survival loading conditions were defined: one with an axial load in the direction of the connected pipe, and the second with a bending load applied to the end of the pipe. In practice, there could also be scenarios where a combination of axial and bending loads could act simultaneously. Crack stability was evaluated at critical locations (shown in Figure 2) for both loading conditions. It was discovered that cracks located at the intersection of the bores in the tee, and cracks in the flange neck are the most "at-risk" when subject to the survival loads (see cracks 1, 2 and 6 in Figure 2).

Hydrostatic testing can also potentially influence the design life of a component. Based on the accumulation of compressive residual stresses, fatigue mean stress and crack growth driving stresses can be lower than the un-hydrostatically tested case. In this assembly, the locations that limit the fatigue life remain largely unaffected by the hydrostatic test, however there is a noticeable increase in fatigue life in locations near a pressurized surface. In a purely elastic evaluation, there is no benefit seen because residual stresses are not considered. Additionally, from a crack life perspective, it was noticed at the intersection of the two bores in the tee, the crack design life was marginally higher with higher pressure hydrostatic tests.

To date, only verification work has been performed on the 20 ksi 5 inch tee and flange assembly. To get a clear picture of this component, and to be in compliance with regulatory requirements, it is also necessary to validate (or test) the design. A failure mode effects and criticality assessment (FMECA) has been established to do just that. Included in the FMECA are potential failures, their causes, and what action can be done to mitigate them. Among others, material testing, NDE and strain gage measurements are proposed as failure mitigation techniques.

In the near future, the work performed for DeepStar CTR 12302 will be provided to the American Petroleum Institute (API) for public reference and use.

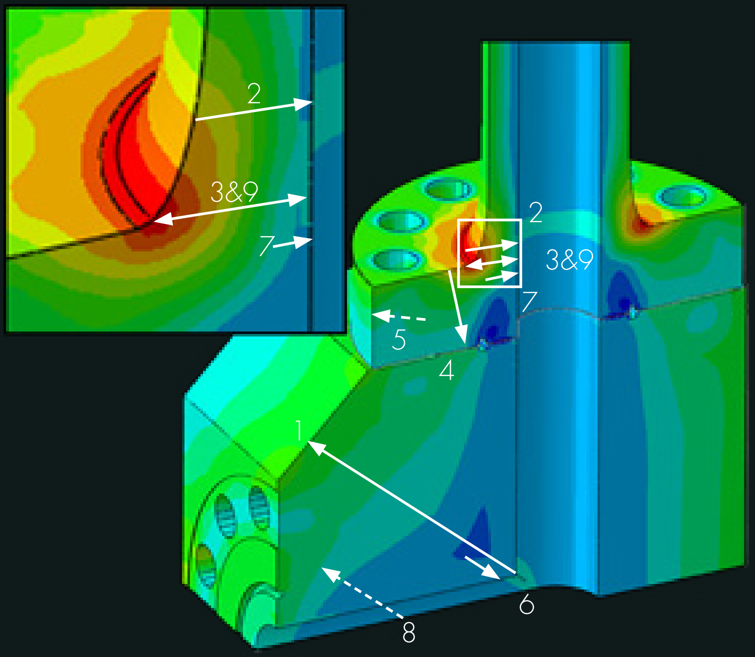


Figure 2. Crack Location "Hot Spots"

PRESSURE TEMPERATURE LIMIT REPORTS AND UPDATES TO P-T LIMITS

RPV Integrity Corner

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For your plant's next update to Pressure-Temperature (P-T) limit curves, consider adopting a Pressure Temperature Limits Report (PTLR).

P-T limits for the Reactor Coolant System (RCS) are used by operators of nuclear plants to maintain plant operation within an acceptable operating window of temperatures and pressures to protect the Reactor Pressure Vessel (RPV) against nonductile failure concerns (Figure 1). All U.S. nuclear power reactors are responsible for maintaining P-T curves as required by Title 10 to the U.S. Code of Federal Regulations, Part 50, Appendix G. P-T curves are required to provide adequate margins of safety during heatup, cooldown, hydrostatic leak tests, and any other conditions of normal operation.

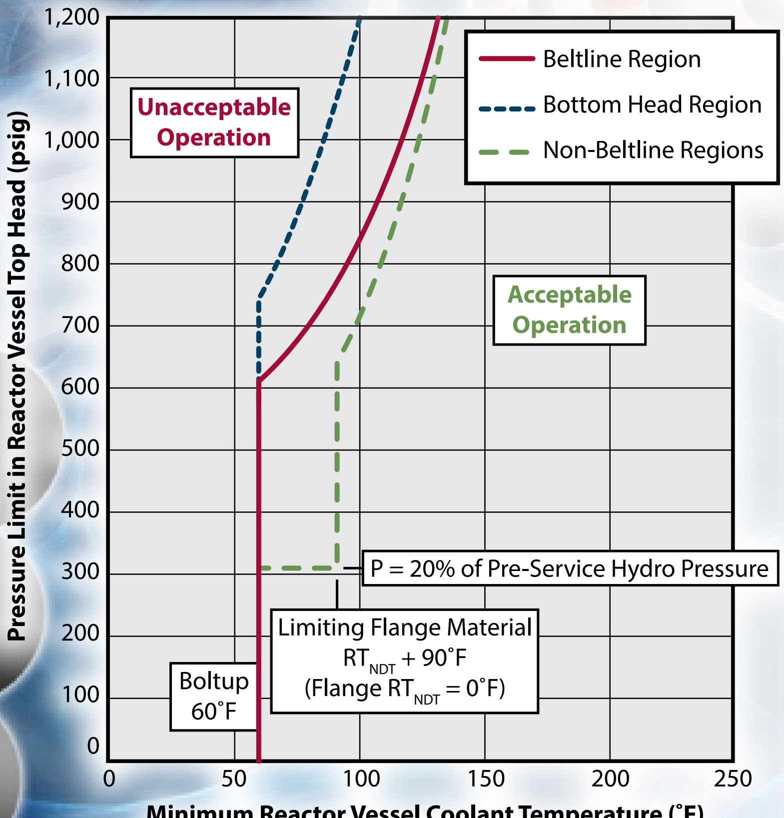

Figure 1. Sample Pressure-Temperature (P-T) limit curves

PTLRs enable significant cost and time savings for utilities. Authorized by NRC Generic Letter 96-03, the major advantage of a PTLR is the ability to remove P-T curves from plant Technical Specifications so that they can be updated within a licensee controlled document, rather than requiring license amendment requests and associated NRC review for changes. Once implemented, the only action required is to submit a copy of the revised PTLR to the NRC for information only.

Updates to P-T curves are needed periodically for various reasons: power uprates, license renewal, updates to fluence, removal of a surveillance capsule, or when the validity period (in effective full power years, EFPY) of the existing P-T curves is reached. The P-T curves are periodically revised as the fracture toughness of the RPV, composed of ferritic steel, decreases as a function of neutron irradiation. Consequently, P-T curves can be maintained more efficiently and at lower cost in a PTLR than in Technical Specifications.

The PTLR must be prepared according to an NRC-approved methodology. The methodology report describes the technical approach used to calculate the P-T curves, while the PTLR contains plant-specific calculations, figures, values, and parameters. We have an NRC-approved P-T curves Topical Report for BWRs that documents the methodology for development of P-T curves and allows for implementation of a PTLR. Structural Integrity can also update existing PTLRs that were prepared to other approved methodologies.

Based on a search of the NRC Agencywide Documents Access and Management System (ADAMS), we found that 44% of

US reactors have implemented a PTLR, with BWRs and PWRs adopting PTLRs at about the same rate.

ADDRESSING THE LATEST REGULATORY GUIDANCE

When your plant next updates P-T curves, the NRC will expect the submittal to address the latest regulatory concerns, such as those described in NRC Regulatory Issue Summary (RIS) 2014-11 that provides updated guidance to utilities on the scope and detail of information that should be provided in RPV integrity and P-T curve licensing applications (see page 30 for a related article).

For instance, nozzles and other vessel discontinuity regions can experience higher stress levels than the highly irradiated vessel shell plates adjacent to the core (Figure 2). As a result, nozzles may be limiting with respect to P-T curves, especially when the fluence of the nozzle location exceeds 1 x 10^{17} neutrons per square centimeter (n/cm^2, E > 1 MeV). RIS 2014-11 clarifies that P-T limits must consider all ferritic components in the Reactor Coolant Pressure Boundary (RCPB), including nozzles and flanges in addition to RPV plates and welds. The effects of nozzles on P-T limits are accounted for using nozzle-specific Finite Element Analyses (FEA) to determine stresses at the nozzle corner where the nozzle meets the RPV (Figure 3).

A search of the NRC ADAMS database for the governing P-T curve reports for U.S. reactors revealed that, P-T curves were issued for two-thirds of reactors before 2014. For one-third of reactors, P-T curves were issued more than 10 years ago. Consequently, at the time the existing P-T curves for many plants were developed, the issues covered in RIS 2014-11 may not have been considered or may not have been evaluated using the most up-to-date technical approaches.

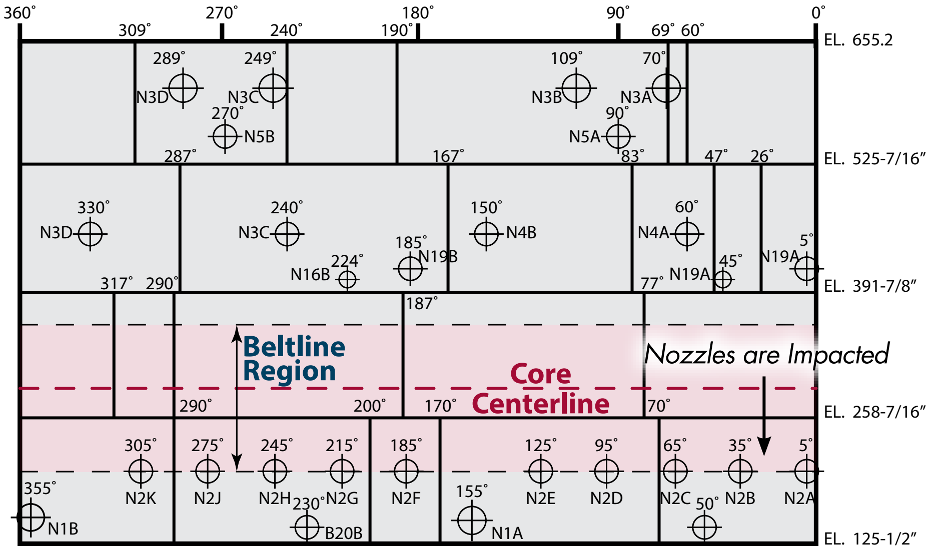

Figure 2. For some vessels, nozzles within the beltline region may define P-T curves that are more limiting than the beltline shell plates and welds.

CONCLUSION

The need to periodically update P-T curves presents an opportunity to implement changes having financial and practical benefits. Implementing a PTLR reduces the cost and timeline for updating P-T curves by eliminating the need for license amendment requests and NRC review. Using the latest methodologies, such as in nozzle-specific stress analysis, can enable more accuracy in analyses and reduce excess conservatism in the resulting P-T limits for added operational flexibility. Ensuring your next submittal addresses all of the latest regulatory issues will minimize Requests for Additional Information (RAIs) and contribute to a smooth review process.

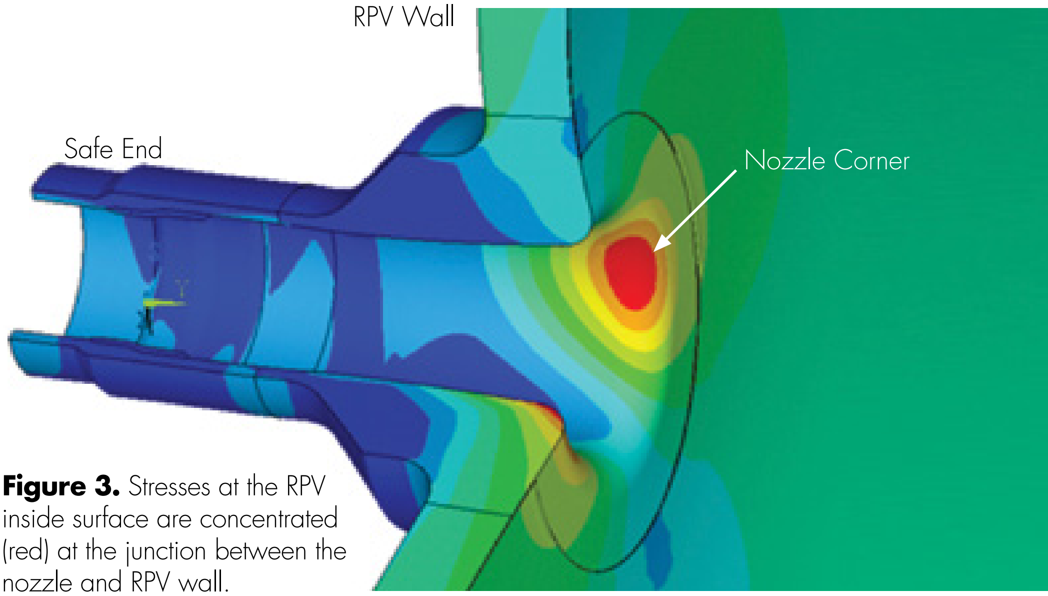

Figure 3. Stresses at the RPV inside surface are concentrated (red) at the junction between the nozzle and RPV wall.

NRC TO RELEASE NEW GUIDANCE ON PRESSURIZED THERMAL SHOCK

By: GARY STEVENS, P.E.

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On July 18, 2016 (ADAMS Accession No. ML16200A206), the Nuclear Regulatory Commission's (NRC's) Advisory Committee on Reactor Safeguards (ACRS) issued a letter to the NRC Executive Director for Operations (EDO) and made the following recommendation:

> ***"Regulatory Guide 1.230 and NUREG-2163 provide thorough guidance and a strong technical basis for licensees to use the Alternate Pressurized Thermal Shock (PTS) Rule, 10 CFR 50.61a, and should be issued."***

So, what is this all about?

I can explain, as I was a co-author for these soon-to-be-released documents during my tenure at the NRC from 2010-2016.

First, here's a brief overview of PTS. PTS is an event or transient in Pressurized Water Reactors (PWRs) causing severe overcooling (thermal shock) concurrent with or followed by significant pressure in the Reactor Pressure Vessel (RPV). During these accident events, significant thermal stresses in the presence of high pressure cause brittle fracture concerns in the RPV.

(PT Curves, on the other hand, address normal operating conditions.) As a result, regulations are in place to safeguard against potential RPV fracture during postulated PTS events. These regulations are located in the Code of Federal Regulations (CFR) at 10 CFR §50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." All PWRs are required to meet the requirements of 10 CFR 50.61. This "PTS Rule" contains limits on the RPV material's resistance to fracture from initiated flaws.

In January 2010, the NRC published a voluntary alternative to 10 CFR 50.61. The alternative requirements are contained in 10 CFR §50.61a, "Alternate Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." This "Alternate PTS Rule" contains revised PTS requirements based on updated analysis methods, and the PTS limits are significantly relaxed compared to the PTS Rule because of the use of less conservative Probabilistic Fracture Mechanics (PFM) analyses. However, the entry requirements to use the Alternate PTS Rule are more stringent in that they mandate the use of the results of a qualified ASME Code, Section XI, Mandatory Appendix VIII examination of the RPV beltline, and comparison of those inspection results to allowed flaw sizes for weld and plate materials.

The NRC is finalizing guidance for using the Alternate PTS Rule in the form of a new Regulatory Guide (RG) 1.230, "Regulatory Guidance on the Alternate Pressurized Thermal Shock Rule." A draft of this guidance was published as DG-1299 in March 2015 (ADAMS Accession No. ML14056A011). Concurrently, the supporting technical basis document for this RG was also published as draft NUREG-2163, "Technical Basis for Regulatory Guidance on the Alternate Pressurized Thermal Shock Rule," (ADAMS Accession No. ML15058A677).

So, now back to answer the question of, "What is this all about?" The ACRS's letter completes one of the steps in the NRC's internal review process for publishing new regulatory guidance. The ACRS reviews and advises the Commission with regard to the licensing and operation of production and utilization facilities and related safety issues, the adequacy of proposed reactor safety standards, technical and policy issues related to the licensing of evolutionary and passive plant designs, and other matters referred to it by the Commission. Their July 18, 2016 memo recommends that the NRC staff proceed with publishing the Alternate PTS Rule guidance. Publication is anticipated by this summer.

So, look for an announcement about the release of RG 1.230 and NUREG-2163 in the Federal Register soon. Or, give us a call and we'll let you know the status of this guidance.

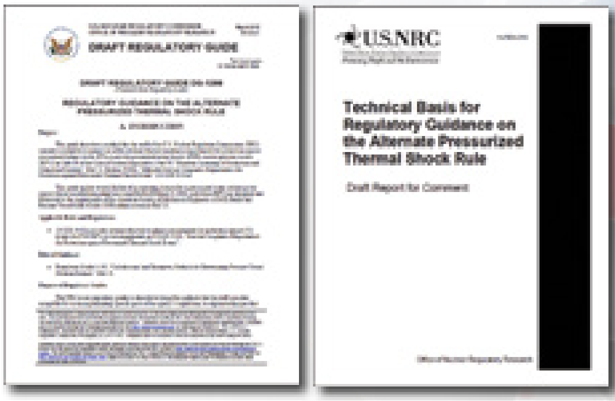
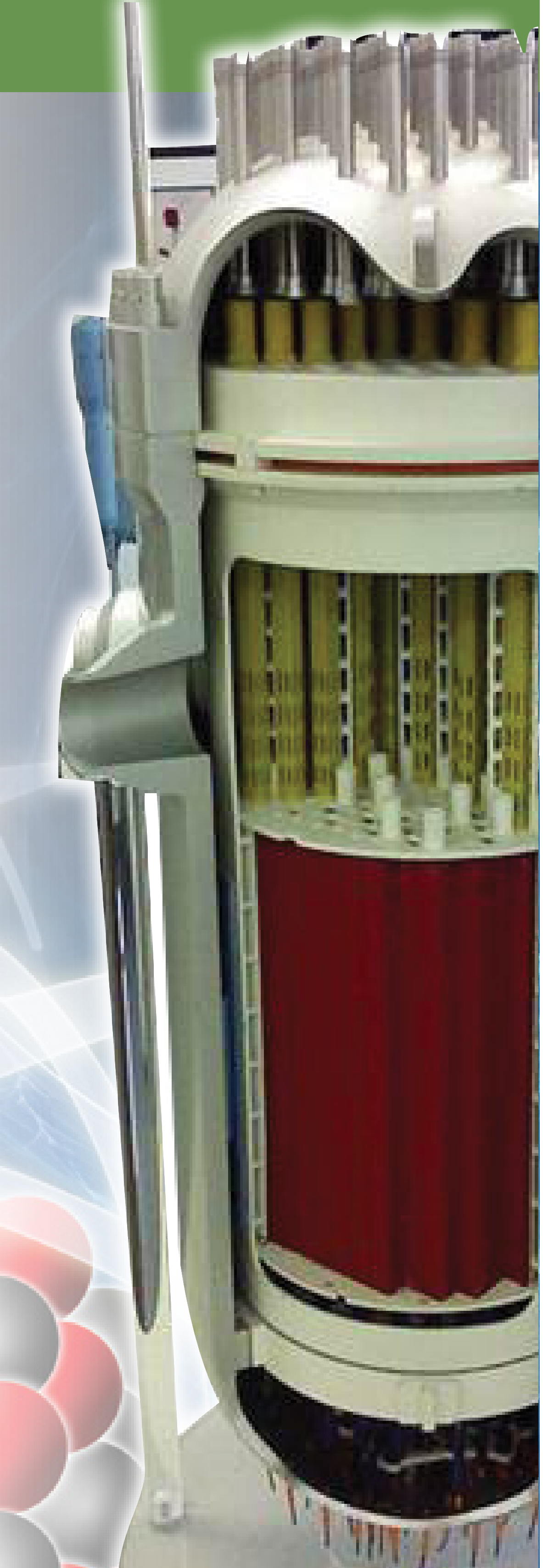


Figure 1. Draft RG 1.230 and Accompanying NUREG-2163

NUCLEAR PLANT FATIGUE ANALYSIS WORKSHOP IS BACK



NPFA 2017
NUCLEAR PLANT FATIGUE APPLICATIONS

August 22-24, 2017
Asheville, NC

Structural Integrity is co-hosting this year's Nuclear Plant Fatigue Analysis Workshop in August. The NPFA is a forum for discussion of fatigue issues facing utility plant staff and its goal is to provide practical lessons and knowledge transfer which can be applied to fatigue management at nuclear power plants.

Utility staff with responsibilities in the areas of operations, system engineering and maintenance, and engineering supervision have found this workshop to be very informative. Engineering vendors and consultants are also invited to share their experience with managing day-to-day fatigue issues, supporting equipment qualification, and conducting fatigue evaluations, including addressing environmentally assisted fatigue. Researchers working in the areas of fundamental understanding of fatigue phenomena, fatigue crack growth, and environmentally assisted fatigue are also encouraged to participate.

Do you have experience or research findings directly related to Nuclear Plant Fatigue Management? The 2017 NPFA Workshop is actively looking for educated and experienced individuals interested in presenting an abstract on your topic. The deadline for a Presentation Abstract, overview of your topic and credentials must be submitted before March 20, 2017.

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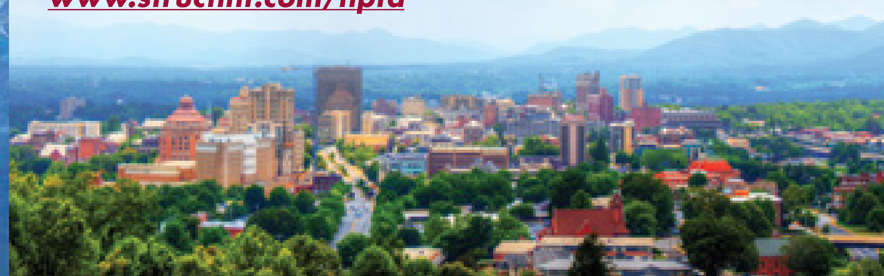

VERIFICATION OF REACTOR PRESSURE VESSEL BELTLINE MATERIAL PROPERTIES

By: TIM GRIESBACH
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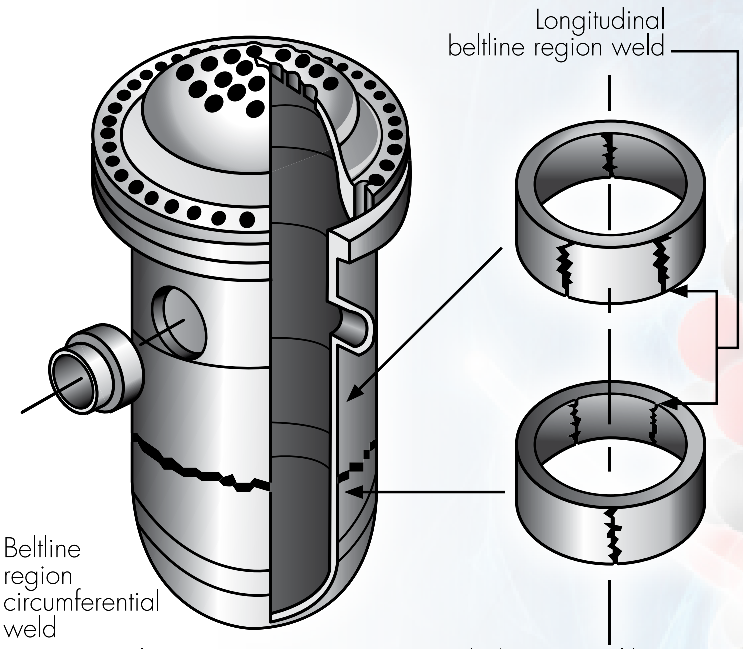
Nuclear reactor pressure vessels are made from many segments of plates, welds and forgings. The Design Basis for the vessel is the original set of documents that define the limiting conditions, as considered by the vessel designer. However, the requirements for nuclear pressure vessel design have changed over time. The very early vessels (prior to 1960) were designed to meet Section VIII of the ASME Boiler and Pressure Vessel Code. Newer vessels were designed in accordance with ASME Section III that took into account material toughness using a reference toughness curve. It required a measured nil-ductility reference temperature correlated to toughness known as RT_{NDT}, and it allowed the design of vessels with less thickness than Section VIII. Other requirements have also changed since the early pressure vessels were designed, such as the need to incorporate changes in the vessel material properties due to irradiation damage. Only limited irradiation embrittlement data existed at the time the early vessels were designed and constructed, but years later as surveillance test data became available, it became obvious that the susceptibility to embrittlement is strongly affected by chemical elements in the vessel steels, such as copper and nickel. Because of the concerns for incorporating the effects of embrittlement of the reactor vessel materials, NRC issued Regulatory Guide 1.99, 10CFR50, Appendix G that specifies the fracture toughness requirements, and 10CFR50, Appendix H that specifies the material surveillance program requirements. The vessel materials adjacent to the core were called "beltline" materials, and Appendix H of 10CFR50 designated beltline materials as those with peak neutron fluence at the end of the design life exceeding 10^{17} n/cm^2 (E > 1 MeV). During the design and selection of materials for the plant surveillance program, those specific materials were chosen as possible limiting materials for consideration of embrittlement.

As plants continue to operate for 60 years or more, the region of materials in the vessel considered to fall within the beltline will expand to other components including nozzles, welds, forgings and areas outside the traditional scope of the beltline. This presents new challenges for determining vessel integrity margins since the material properties for these additional materials must be characterized and demonstrated to be in compliance with the ASME Code and NRC regulations for plant operation. These vessel integrity concerns include Pressure-Temperature (P-T) limit curves, Pressurized Thermal Shock (PTS), and evaluation of low Epper Shelf Energy (USE) materials. More detailed



A Typical PWR Reactor Pressure Vessel Showing Beltline Region Including Welds

analyses are required to justify that all criteria are met for the remainder of the plant operating life, taking into account the changes in properties due to embrittlement as evaluated according to Regulatory Guide 1.99, Rev. 2. The reactor vessel fabrication records and Certified Material Test Reports (CMTRs) are needed in order to perform these analyses, to predict the amount of embrittlement with increasing fluence, and to confirm that all criteria are met throughout the desired plant operating period. When questions arise about the vessel integrity margins, it is essential that plant owners have access to the original records and material test reports so that the analyses can confirm the margins, or be able to demonstrate additional margins, for extended plant operation.

Over the past several years there have been a number of new issues related to reactor vessel integrity and vessel beltline materials. For example, here are just a few:

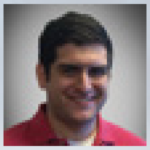
1 uncertainties about the method for determining initial nil-ductility reference temperature (RT_{NDT}) using the Branch Technical Position 5-3,

2. the presence of hydrogen flakes in the Doel 3 and Tihange 2 reactor vessels in Belgium,
3. large amounts of carbon macrosegregation occurring in forgings made in France that was detected in reactor pressure vessels and steam generators,
4. nozzles made from SA508-2 forgings that became part of the vessel beltline region as fluence increases with age and for which there is limited materials data,
5. missing or incomplete data for some reactor vessel beltline materials, and
6. surveillance data that shows higher-than-expected RT_{NDT} shift or USE drop for the matching limiting materials in the reactor pressure vessels.

These issues and concerns are very real for some European plants, and there may be similar concerns for U.S. plants as examinations of the reactor vessel materials continues. Many of these issues and questions can be resolved by having ready access to the vessel fabrication records and CMTRs and by evaluating the reported information using available materials databases, state-of-the-art techniques and tools, and by employing appropriate methods to demonstrate acceptable margins.

We can assist utilities with managing these vessel integrity concerns starting with compilation of the vessel fabrication records, surveillance reports, review of fluence calculations and implementation of predictive models to determine changes in material properties due to embrittlement, analyzing the materials behavior for all operating conditions, and then documenting the results for licensing purposes such as a power uprate or license renewal application.

CARBON MACROSEGREGATION
IN LARGE FORGED COMPONENTS



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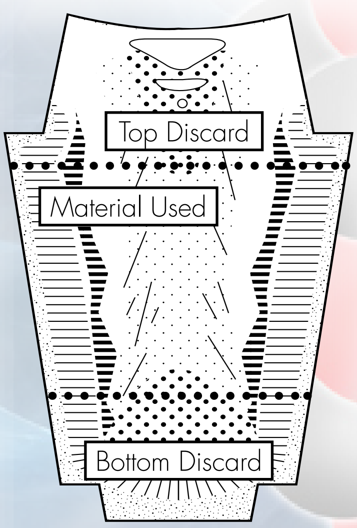
In large steel ingots, the material condition known as carbon macrosegregation is defined as variations in carbon content that exist in the ingots, ranging in length from centimeters to meters. This is a common phenomenon that occurs during the solidification of large steel ingots. Existence of carbon macrosegregation is undesirable in forged components, as localized carbon levels may exist that exceed material specification limits and due to the potential to reduce fracture toughness and ductility in these regions. Forging vendors follow specific procedures to mitigate the existence of carbon macrosegregation in the components they manufacture, which involves removing the portions of the ingot that experience elevated levels of carbon.

A current industry issue being investigated is the existence of excessive carbon macrosegregation in large forging materials within operating nuclear plant components. This issue was discovered after demonstrations of compliance with new fracture toughness requirements were performed by AREVA as required by the French Nuclear Safety Authority (ASN). Destructive testing on Reactor Pressure Vessel (RPV) heads manufactured by AREVA subsidiary, Creusot Forge, was performed which identified elevated carbon bands around the center section of the forged heads. Ongoing investigations by the industry, including the U.S. Nuclear Regulatory Commission (NRC), to identify the existence of carbon macrosegregation in large forged primary system components in U.S. reactors have not yet identified any conditions adverse to safety.

Structural Integrity, in conjunction with industry groups, has been involved during these ongoing investigations, providing subject matter expertise in material science and probabilistic fracture mechanics to assess any potential risks or vulnerabilities that may exist in the U.S. nuclear fleet. One such investigation performed is an evaluation on the significance that the presence of carbon macrosegregation has on the fracture toughness of RPV beltline materials that are bounding for the U.S. fleet. Probabilistic fracture mechanics analyses were performed to determine the limiting through-wall cracking frequency values for RPV materials with reduced fracture toughness due to carbon macrosegregation, following the methodology and acceptance criteria used in the Alternate PTS Rule, 10 CFR 50.61a "Alternate Fracture Toughness Requirements for the Protection Against Thermal Shock Events." Again, as of the publishing of this article, these ongoing investigations have not identified any conditions adverse to safety with respect to carbon macrosegregation in U.S. nuclear fleet components with large forgings.



ISSUE WITH DETERMINING THE LIMITING POINT FOR A NOZZLE FOR PRESSURE-TEMPERATURE LIMITS

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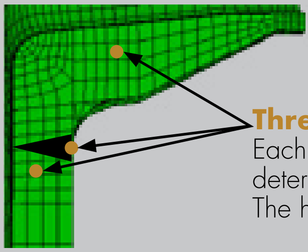
One of the issues address in Regulatory Issue Summary (RIS) 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," dated October 14, 2014, is that P-T limit submittals must address more than just materials with the highest reference temperature. In particular, structural discontinuities such as nozzles must also be addressed. The following pictorially explains the issue with nozzles.

The limiting point on a nozzle for P-T Curves has three competing factors:

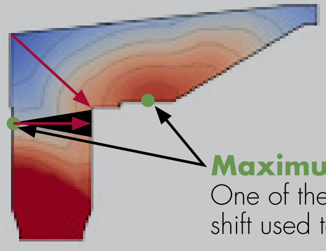
1. Material
2. Fluence
3. Stress

The following illustrations depict the above factors (PWR inlet nozzle shown).

1. Limiting Nozzle Point with Respect to Material



2. Limiting Nozzle Point with Respect to Fluence [a]:

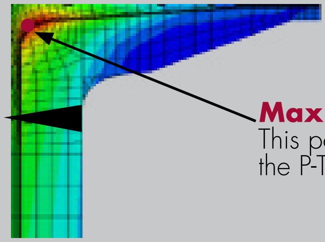


Footnotes:

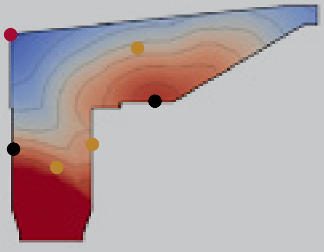
(a) E.N. Jones, and B.P. Richardson, "Evaluation of DPA Profiles in Westinghouse 3-Loop and 4-Loop PWR Inlet and Outlet Nozzle Forgings using the RAMA Fluence Methodology," presentation at the Materials Reliability Program Technical Advisory Committee Joint Meeting, November 13, 2012 (Slide 25).

(b) S. Yin, B.R. Bass, and G.L. Stevens, "Stress and Fracture Mechanics Analyses of Boiling Water Reactor and Pressurized Water Reactor Pressure Vessel Nozzles – Revision 1," Oak Ridge National Laboratory Report No. ORNL/TM-2010/246, June 2012, ADAMS Accession No. ML12181A162 (Figure 53).

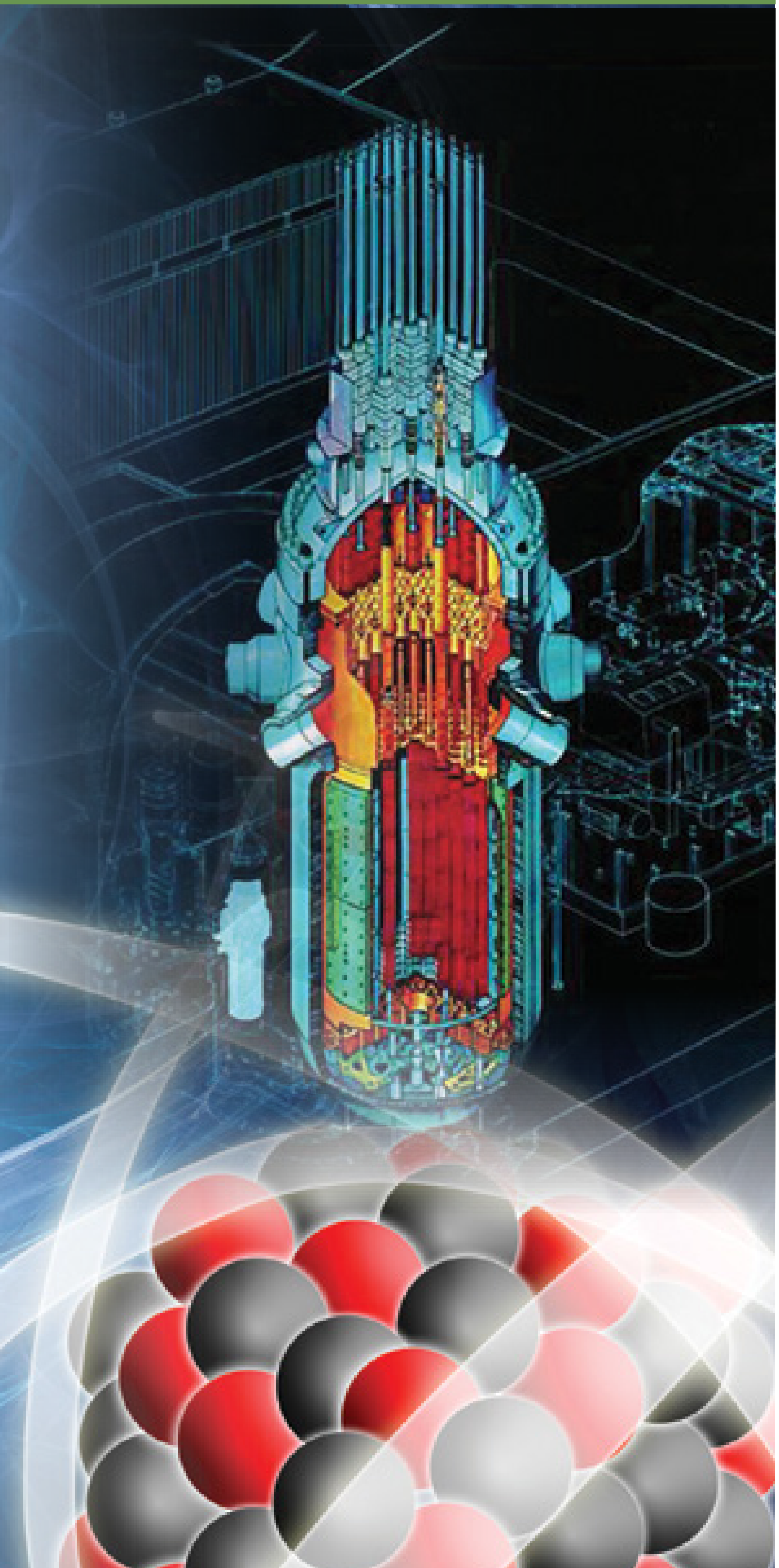
3. Limiting Nozzle Point with Respect to Stress[b]:



So, the question is, which point controls the P-T curve?



ANSWER: The answer is plant specific.
So, do your P-T curves adequately encompass all of your RPV nozzles? If you're not sure, or if you have any questions, give us a call.



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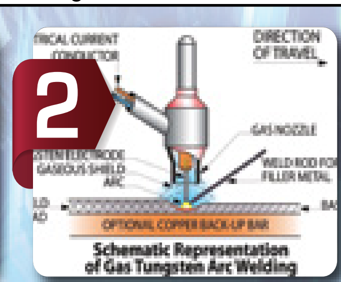

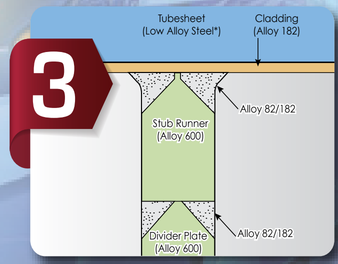

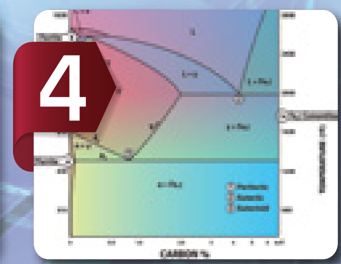

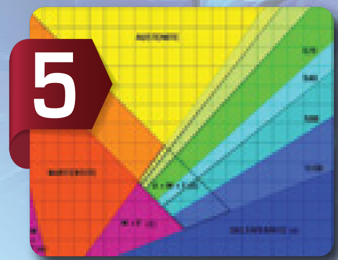

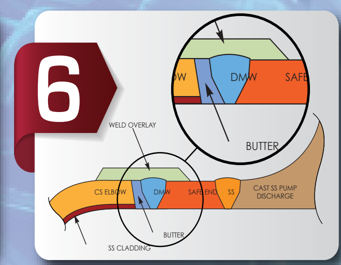

APPLYING FRACTURE MECHANICS TO ADDRESS EMERGING ISSUES IN OIL AND GAS

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Structural Integrity's roots lie in evaluating and preventing mechanical failures in the nuclear power industry. Fracture mechanics is the principal engineering discipline applied to support these evaluations, and has been an area of expertise and source of work for Structural Integrity since its founding in 1983. Through this work, we have become recognized as an industry expert in component evaluation, developing advanced software tools to aide in fracture mechanics analyses and participating in the development of ASME Code rules for evaluation of in-service inspections.

While fracture mechanics work remains a core engineering discipline for the work we perform in the nuclear and fossil industry, new regulations in the oil and gas industry targeting gas transmission pipelines and subsea components will require a significant increase in the application of fracture mechanics. Applying lessons learned from the nuclear and fossil industries, we are continuing to build and apply our Fracture Mechanics expertise to solve unique problems emerging in the oil and gas industries.

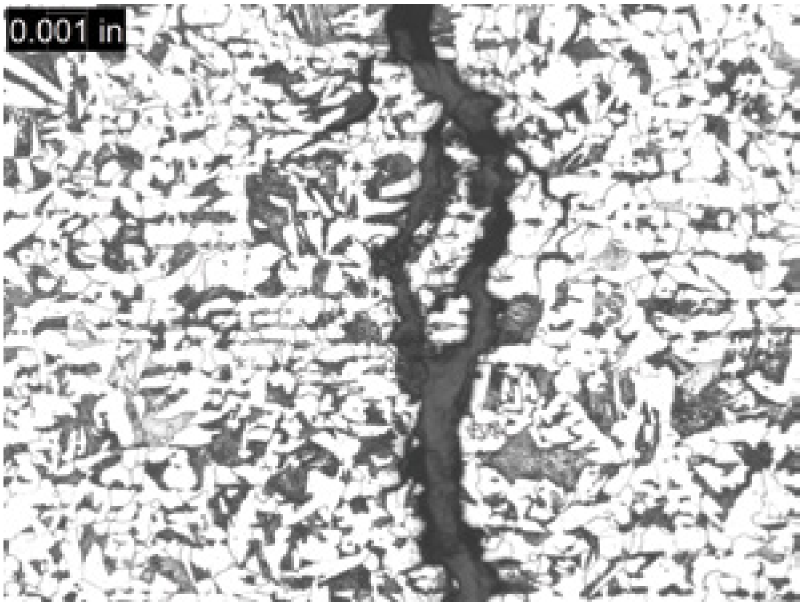
GAS PIPELINE NPRM FRACTURE MECHANICS REQUIREMENTS

The U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) recently issued a Notice of Proposed Rulemaking (NPRM) titled Safety of Gas Transmission and Gatheering Pipelines proposing extensive changes to 49 CFR Part 192. The proposed regulation includes new requirements for verification of pipeline material, Maximum Allowable Operating Pressure (MAOP) verification, pipeline assessments, integrity management and repairs. It also includes new detailed guidance on fracture mechanics modeling for failure stress and crack growth analysis.

Section 192.624 of the NPRM specifies new methods for verifying the MAOP of designated gas pipelines nearly all of which require a rigorous fracture mechanics analysis if there is reason to believe the pipeline segment contains or may be susceptible to cracks or crack-like defects. The analysis requires modeling for failure pressure considering both ductile and brittle failure modes, incorporating fatigue models to predict flaw growth, and including a sensitivity analysis to determine estimates of time to failure for cracks. The NPRM prescribes a very conservative approach of assuming minimum strength and toughness properties when determining failure pressure for a known defect size. For example, maximum properties, Charpy V-Notch (CVN) of 120 ft-lbs, are to be used for determining the largest flaw that could have survived a pressure test, while when analyzing in-line inspection assessments, default CVN values of 5 ft-lbs for base material and 1 ft-lb for ERW seam bond line defects are to be assumed when data are not available. These values are extremely conservative and operators will need to implement extensive data gathering and material testing in addition to analytical support to justify the use of conservative, but more realistic values.

SUBSEA REGULATORY FRACTURE MECHANICS REQUIREMENTS

Another area of key concern for the oil and gas industry, specifically in the subsea deepwater production market, is ensuring the integrity of High Pressure, High Temperature (HPHT) components using existing instrumentation. The fatigue life of HPHT subsea completion equipment and other thick section components becomes an increasing concern. ASME and



API code guidance does not exist for components that now are faced with shut-in exposure above 15,000 psi class. Designers are having to develop an approach and technical basis for component performance when challenged by high temperatures and pressures (up to 350°F and 20,000 psi), a corrosive environment, and complex stress states induced by, among other things, thermal transients and pressure cycling. Stress cycles with sufficient frequency and severity in the HPHT environment could initiate a fatigue crack. If allowed to continue, a fatigue crack could propagate exponentially through the wall of the component and lead to a leak or even general structural failure. Further complicating this will be when Corrosion Resistant Alloy (CRA) liners are needed to combat sour service environmental conditions. Once a crack propagates through the liner, the failure threat changes to Sulfide Stress Cracking (SSC) and the fatigue crack growth rates will change

Draft regulations for HPHT equipment proposed by the Bureau of Safety and Environmental Enforcement (BSEE) state that "the lessee and operator must submit a summary of the proposed load monitoring methods and record keeping for each of the assemblies or components that are considered fatigue sensitive."

STRUCTURAL INTEGRITY FRACTURE MECHANICS OIL AND GAS EXPERIENCE

We have completed a number of recent fracture mechanics projects for the oil and gas industry. Some recent examples of project work completed include:

Modeling and evaluation of cracks at hard spots

In a recent project for a major pipeline operator, a deterministic analysis using Linear Elastic Fracture Mechanics (LEFM) was completed for pipelines with metallurgical hard spots and hydrogen induced cracking. Applied stress intensity factor calculations were performed using Structural Integrity proprietary software (pc-Crack) – software that analyzes and predicts flaw behavior, including calculation of crack growth rates and critical crack sizes for pressure vessels and piping. The analysis used CTOD (crack-tip opening displacement) and Charpy V-Notch data to estimate fracture toughness for various hardness values. The analysis was validated with respect to field failure data and a series of full scale burst tests performed circa 1967 on similar pipes containing cracks of various lengths. Critical crack size and safety factors as a function of temperature and pressure were determined from this analysis and used to guide repair and replacement activities.

SCC Analysis and APTITUDE

Due to significant and extensive Stress Corrosion Cracking (SCC) discovered for another major pipeline operator in the Northeastern United States, Structural Integrity was retained to help refine their SCC Management Plan, categorize SCC identified (in accordance with ASME B31.8S), and help define re-assessment intervals using guidance provided in the NPRM. As part of the evaluation, Structural Integrity developed a software tool, APTITUDE™, that employed multiple methodologies to evaluate crack-like defects covering the full spectrum from low (brittle) to high (ductile) toughness regimes. The tool was developed to analyze axially oriented cracks present in pressurized steel cylinders with a wide range of material properties (yield strength, flow stress, fracture toughness) and pipe/flaw geometry

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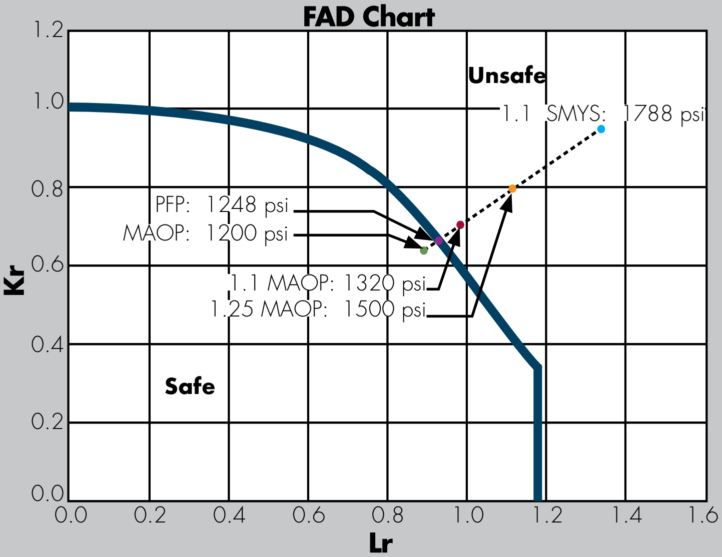
APPLYING FRACTURE MECHANICS TO ADDRESS EMERGING ISSUES IN OIL AND GAS CONTINUED



(diameter, wall thickness, through-wall or surface crack, crack length and depth) using proven methodologies. The tool was developed to calculate the predicted failure pressure (from reference standards), determine crack categories, and establish re-assessment intervals. The following methodologies for evaluating crack-like defects were included:

- Modified Ln Secant
- API 579 Level 2 - Failure Assessment Diagram (FAD) Approach
- Finite Element Based Limit Load Approach (Limit Load)

Structural Integrity also incorporated our advanced fracture mechanics expertise to incorporate logic that identifies a recommended method to ensure an accurate yet conservative result based on applicable toughness regimes (low, intermediate, and high toughness) and pipe/flaw geometries.

Fracture Mechanics Training for Pipeline Operators

Dr. Peter Riccardella recently provided on-site training for a key client on "Fracture Mechanics for the Pipeline Industry". The training covered topics ranging from introductory concepts and principles to fracture mechanics as applied in the NPRM. Real example problems were covered with corresponding analytical approach and results.

NPRM Recommended Default Toughness Values

Working with a major gas association, Structural Integrity was retained to complete a statistical analysis of known pipe materials in published and proprietary sources. The sources included material with known defects that were burst tested and further analyzed along with lab data that was collected. The aim of this study was to identify bounding toughness values for fracture mechanics evaluations when material properties are not known or adequately documented.

A statistical analysis was performed of gas pipeline materials toughness data from a number of sources, including both ERW seam weld and pipe body base materials. The analysis revealed that the default toughness values proposed for fracture mechanics modeling in the NPRM, represent overly conservative values. SI's statistical analysis concluded that more reasonable default toughness values should be used when evaluating crack defects, consisting of 13.0 ft-lb for pipe body toughness and 4.0 ft-lb for the long seam welds of vintage pipe (such as pre-1970 ERW seam welds). SI believes The use of these values is more appropriate in most cases (representing the 90th percentile) when analyzing crack-like defects with unknown toughness.

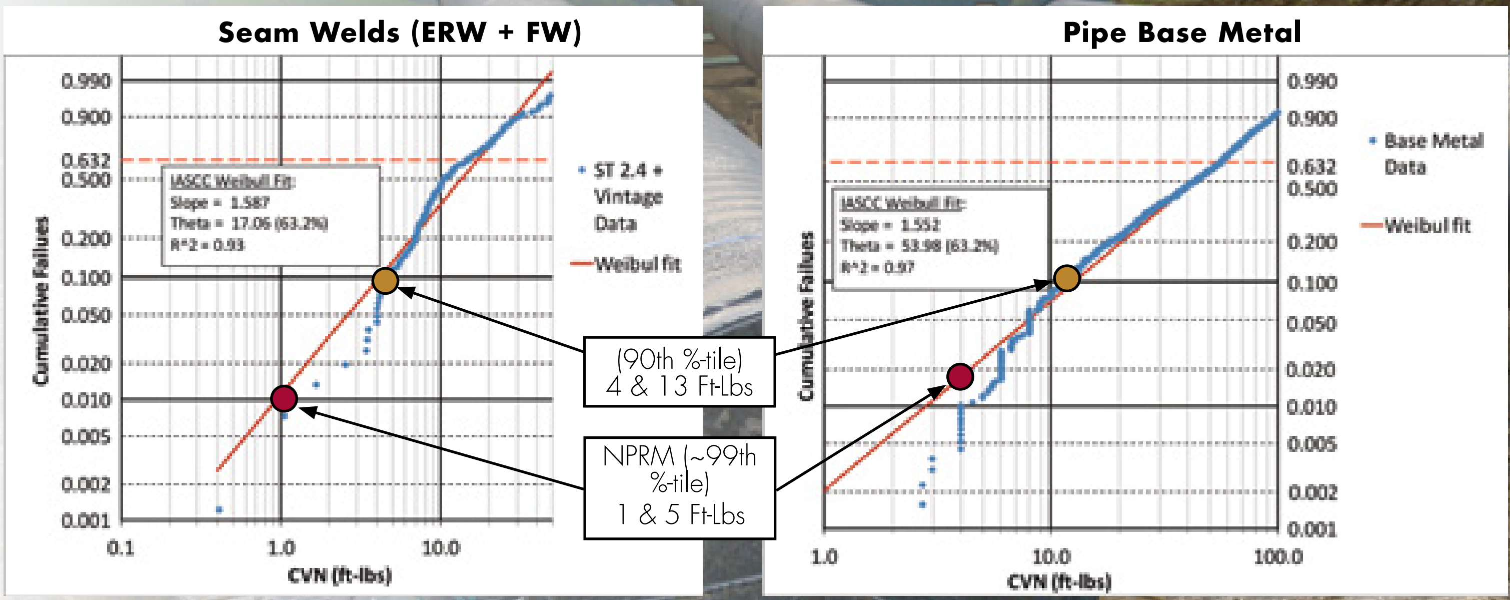
Subsea Component Analysis

Structural Integrity was a key contributor in API Technical Report 17TR8 (TR8), which was recently revised to serve as a guideline for designing HPHT subsea components subject to high pressure (>15 ksi) and high temperature (>350 °F). TR8 is intended to serve as a technical guidance document to augment other standards when operating above 15,000 psi or 350°F. . In the TR8, fracture mechanics is presented as a method for establishing a fatigue life. Coupling environmentally specific fatigue crack growth data with initial cracks sizes, identified by the resolution of the applied Non-Destructive Examination (NDE) technique, the total crack propagation life can be identified. In the TR8 report, maximum allowable life is defined as half of the number of cycles to predicted failure. Furthermore, in the unplanned event that design conditions are exceeded, known as a survival event, the TR8 recommends that a potential crack should remain stable.

Crack stability can be assessed in many ways, and the TR8 directly references the methodologies in ASME B&PVC VIII-3, API 579-1/ASME FFS-1 and BS 7910. In conjunction with these standards, TR8 identified the highly dependent nature of fracture as environment, and appropriately warns an operator should be aware of potential detrimental environmental effects.

To get an accurate representation of the number cycles and their magnitudes that contribute to crack growth, TR8 offers load monitoring as a method of accounting for operating cycles. Load monitoring ensures "in-service" loading falls within the design criteria, and since generally service loads are less than the design loads, load monitoring provides a more accurate representation of load cycles and subsequently fatigue life.

To date, TR8 serves as a foundation of the HPHT deep water equipment design and provides a basis on which the deep water industry can expand in the future.



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FAILURE ANALYSIS APPLIED TO WIND TURBINES

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Wind turbines are relatively new and complex systems, consisting of a wide range of technologies from mechanical gears and bearings, aerodynamics, electrical generators to composite (fiber reinforced) structures. As the wind turbine fleet ages, damage accumulates that can lead to catastrophic failures and long, expensive operational downtimes. Understanding how and why these damage mechanisms and/or failures occur can help prevent, mitigate and assess the risk of future events.

Figure 1. Site inspection for fractured blade and impacted tower.

Failure analysis on any component requires application of forensic techniques. To perform the analysis, a series of questions need to be answered to determine what failed, how it failed, and why it failed. The series of questions are outlined below.

STEP 1: WHAT COMPONENT FAILED?

Perform Site Inspection: a detailed incident site inspection can determine which of the following occurred: hub or blade detachment, blade fracture, tower damage or collapse, generator fire, etc. Figure 1 shows an example of a catastrophic failure where a blade detached from the hub and hit the tower. Upon site inspection it was discovered that the blade impact dented the tower.

STEP 2: WHERE DID THE FAILURE ORIGINATE?

Fractography: visual and macroscopic examination of the fracture features can pin-point specific areas of interest for detailed destructive and microscopic analysis. Recently, we were retained to provide analysis of a wind turbine failure where the main shaft fractured causing the hub and blades to fall to the ground. Figure 2 shows an example of macroscopic inspection of the shaft's fracture surface that pin-pointed the fracture origin area. This area was then cut-out and inspected in a Scanning Electron Microscope (SEM).

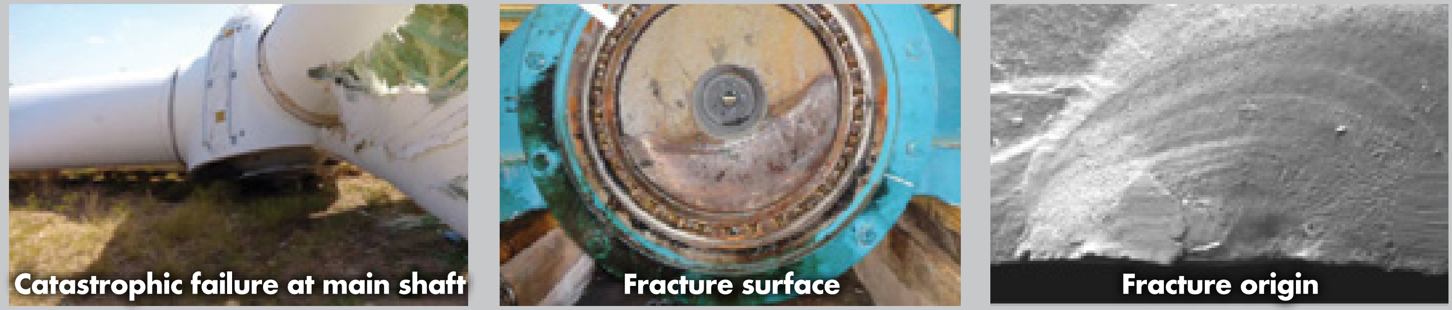

Figure 2. Macro and microscopic inspection of main shaft

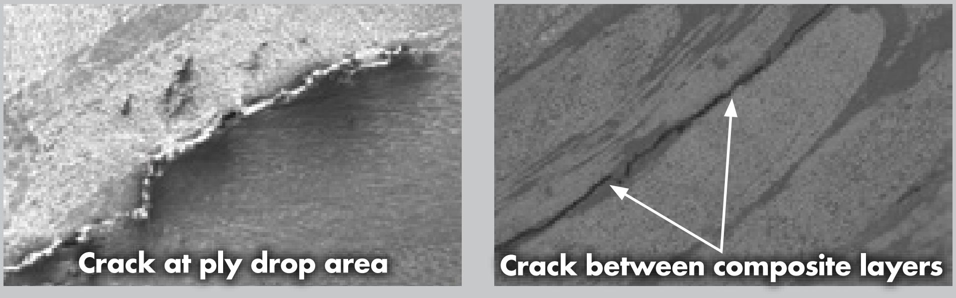

Figure 3. Cracking between composite layers

STEP 3: WHAT WAS THE DRIVING FAILURE MODE?

Microscopic analysis: different materials exhibit specific microscopic features at fracture surfaces that provide information on the mode of failure such as tension, compression, torsion due to an overload or fatigue. This process can also reveal the presence of cracking, inclusions, voids, porosity, oxidation and other damage and material degradation features. For example; wind turbine blades are made of laminated composites and cracking can occur between layers, referred as delamination, and at ply termination points (ply drops at resin pockets) and are sometimes only found microscopically as shown in Figure 3.

These 3 steps are based on physical evidence and are the basis for identification of the failure mechanism. To get to the root cause and mitigation of future failures, additional questions need to be answered:

STEP 4: WHAT WAS THE COMPONENT'S OPERATIONAL LOADING AND ENVIRONMENT?

The loading conditions such as wind speeds, humidity, lightening, yaw and pitch angles and rotor speed (rpm) can be obtained from operational data from inspection reports, Supervisory Control and Data Acquisition (SCADA), Condition Monitoring System (CMS), weather, etc. This information can be the inputs to component stress and fatigue analysis. The results of such analysis can be compared to the OEM's design allowable and to industry standards/guidelines such as those from DNV-GL and IEC.

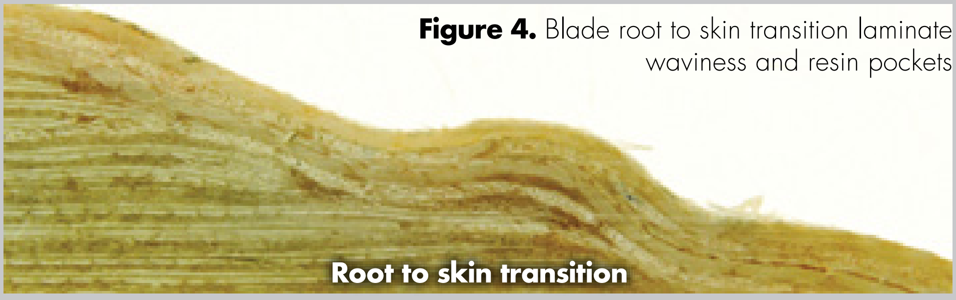

Figure 4. Blade root to skin transition laminate waviness and resin pockets

STEP 5: WHAT WAS THE STATE OF THE COMPONENT BEFORE FAILURE?

The design of the component was based on specific geometry and material properties but regularly these are different or have degraded due to exposure to different environments. A careful review of manufacturing procedures, inspection reports, SCADA data, and Balance of Plant (BOP) performance can determine component structural degradation, pre-existing damage or manufacturing defects. Mechanical properties can be tested following testing standards to get actual material properties and assess if the material is compromised. Material degradation or composition can be evaluated via metallography and chemical composition analysis for metallic components while FTIR (Fourier Transform Infrared Spectroscopy), DSC (Differential Scanning Calorimetry) or GC-MS (Gas Chromatography Mass Spectroscopy) analyses can be performed for composite materials. Figure 4 shows a cross-section of a blade root to skin transition area where "waves" resulted from the manufacturing process resulting in large resin pockets at ply drops, which can weaken the overall structure/material.

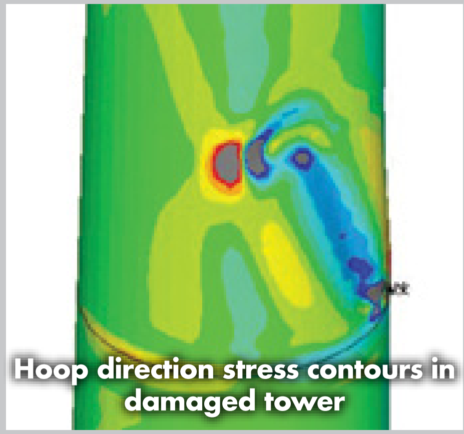

Figure 5. Tower impact damage finite element analysis

STEP 6: WHAT IS THE EFFECT OF PRE-EXISTING DAMAGE OR MANUFACTURING DEFECTS?

If damage or defect is found, it is important to understand if and how it will affect the component's performance. Stress analysis and fracture mechanics that simulate the presence of damage/defect can estimate the effect of these on the component's stress distribution and strength. An example of such stress analysis is shown in Figure 5 for a damaged wind turbine tower. Following stress analysis, a revised component lifetime can be estimated using various fatigue analysis methods providing the information needed to plan inspection, repair or replacement intervals.

STEP 7: ARE THESE DAMAGE/DEFECTS PERSISTENT AMONG THE FLEET?

Last, but not least, is to evaluate whether this is an isolated event or is it a systematic issue. Depending on the component, damage/defect type, area of interest and accessibility, different non-destructive inspection techniques may be used such as dye penetrant or phased array ultrasonic examination. The key at this stage is the interpretation of these results and a technique's effectiveness in identifying the damage/defect in other components. Another benefit of such inspections is to gather information of the damage/defect size and specific locations per component/turbine, which allows for lifetime estimation and informed operations and maintenance scheduling.

Unusual Hydrogen Damage Failure

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While hydrogen damage is most often associated with severe gouging on the internal surface of a tube, it can occur in the absence of gouging. Structural Integrity received four waterwall tube sections from a coal fired unit. An Ultrasonic (UT) inspection had detected hydrogen damage ranging from moderate to severe. The table below summarizes the identification, location, and damage level detected based on the UT inspection for the tubes received.

Tube	Location	Damage Level
5	Rear Nose Arch	Severe
7	Front Deflection Wall	Severe
8	Front Deflection Wall	Moderate
83	Rear Nose Arch	Moderate - Severe

We are asked to examine the front waterwall deflection and rear nose arch tubes for hydrogen damage and to assess the extent of the damage.

A ring section was cut through regions identified as containing hydrogen damage from each tube section (Tubes 5, 7, 8, and 83) and prepared for metallographic examination. The prepared rings were examined using a metallurgical microscope and no obvious hydrogen damage was observed. In order to provide better edge retention and increased sensitivity, smaller sections were removed from the hot sides of Tubes 5, 7, and 8, mounted, and prepared for metallographic examination. Upon closer examination, possible hydrogen damage was observed in all three tubes. Figure 1 shows the typical appearance of the hydrogen damage observed in Tubes 5, 7, and 8. The hydrogen damage consisted of partial separation of the ferrite grain boundaries (fissures).

A sample was removed from the hot side of Tube 83 and flattened, which opened up a crack on the internal surface (Figure 2). The crack was not associated with gouging. After the sample was flattened, it was cross-sectioned, mounted and prepared for metallographic examination. Figure 3 shows the

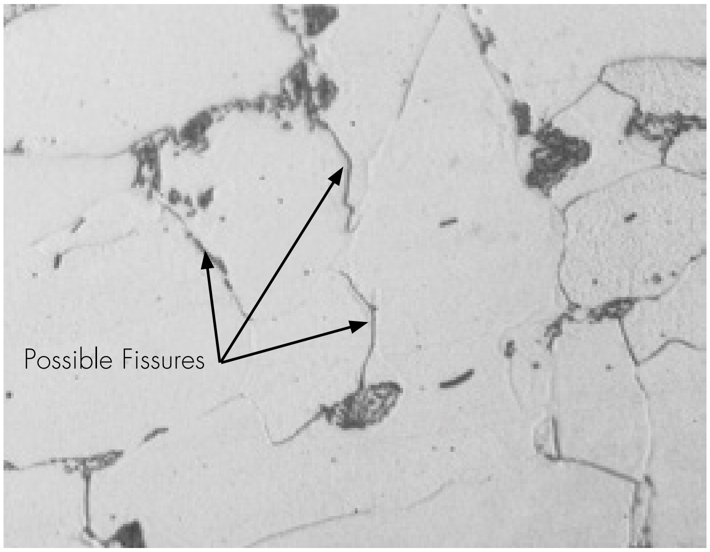


Figure 1

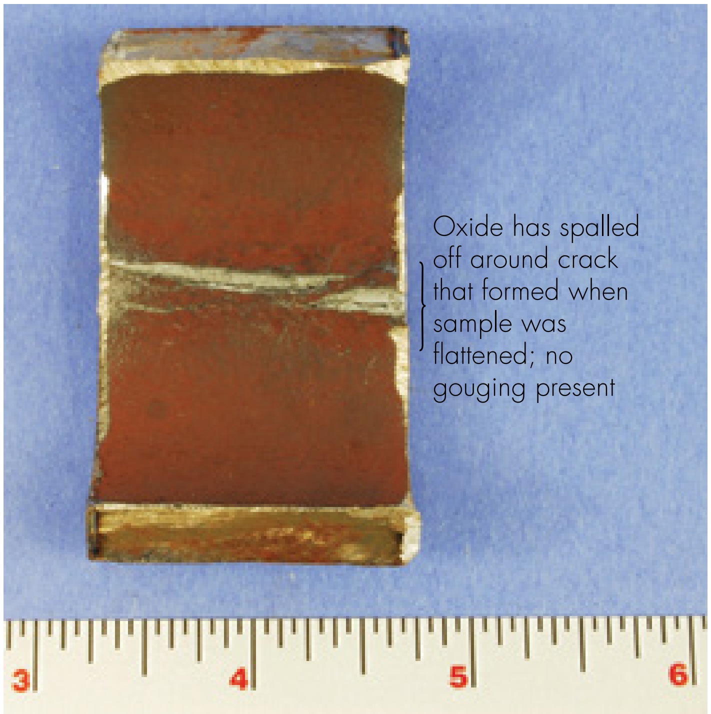


Figure 2

Structural Integrity has an online toolkit to help identify damage mechanisms for boiler tubes. Visit PlantTrack tools to learn more about caustic gouging and other mechanisms at https://planttrack.structint.com/planttracktools

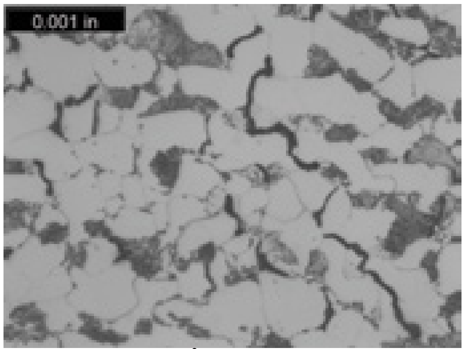


Figure 3

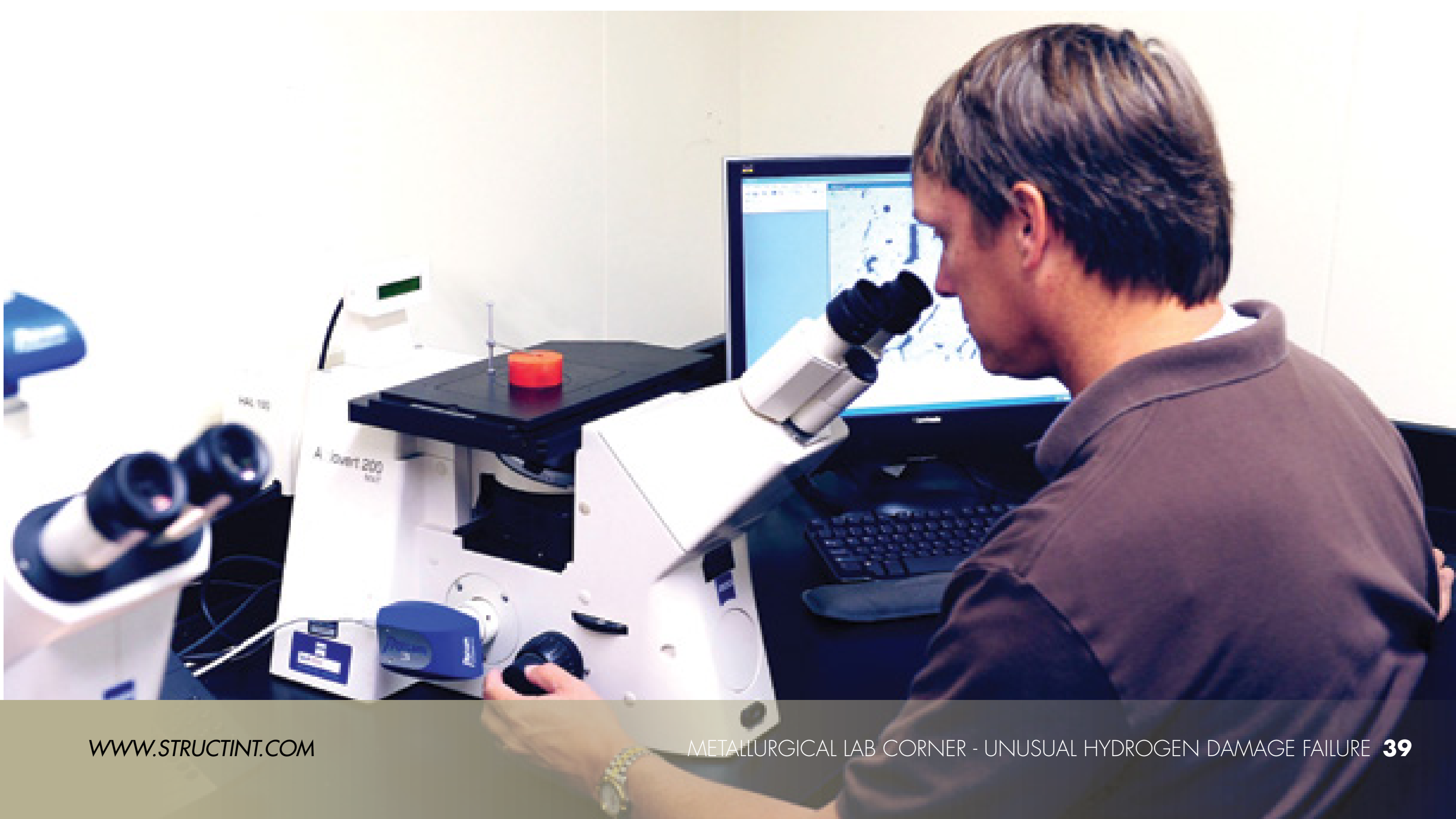
grain boundary fissuring, which became much more evident because the flattening caused the fissures to open. The hydrogen damage had penetrated about half way through wall.

The internal deposit loading was measured on Tubes 7, 8, and 83 and the results are provided in the table below. The heaviest deposit loading value was associated with the most severe hydrogen damage based on the inspection results.

Tube	Degree of Hydrogen Damage	Internal Deposit Loading on Hot Side
7	Severe	290.9 g/ft^2
83	Moderate-Severe	219.2 g/ft^2
8	Moderate	70.0 g/ft^2

The waterwall tubes contained irreversible hydrogen damage. No severe ID wastage was observed on these tubes. This agrees with the ultrasonic inspection, which did not detect any significant wall thinning associated with the hydrogen damage detected on the deflection and nose arch tubes. The appearance of the hydrogen damage was not typical. The damage consisted of discrete grain boundary fissures, which were not readily discernible. A major factor contributing to the hydrogen damage in the deflection and rear arch tubes is the heavy internal deposit buildup. The heavy deposits would have shielded the corrosion sites so that the hydrogen atoms formed during the corrosion process were not washed away, perhaps allowing the hydrogen damage to occur rapidly and before significant gouging occurred. The heavy deposits would also act as a thermal barrier, which increases the metal interface temperature. The increased metal interface temperature may have resulted in increased corrosion rate, similarly allowing the hydrogen damage to form before significant gouging occurred.

We recommended replacing all severe and moderate-severe damaged tubes and then performing a chemical clean of the unit to remove the very heavy deposit buildup and help eliminate the continued formation of hydrogen damage in the unit.



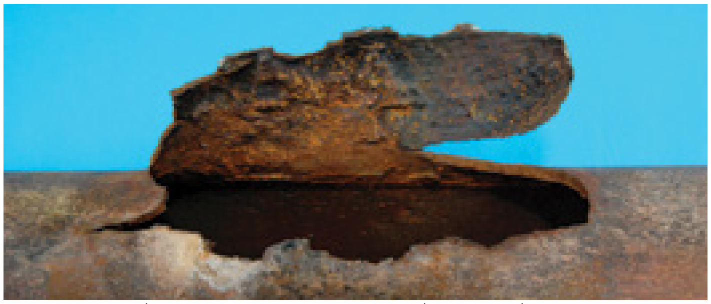
METALLURGICAL LAB CORNER
FEATURED DAMAGE MECHANISM

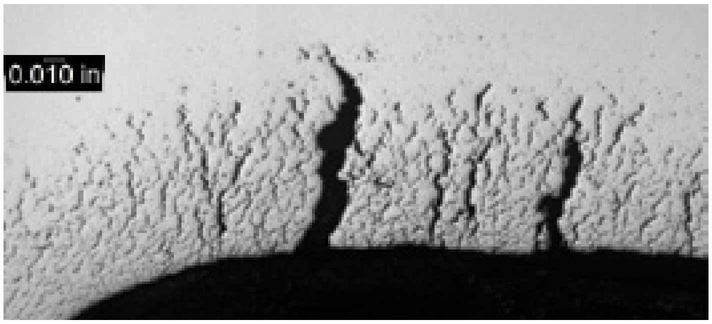
Hydrogen Damage to Conventional Fossil Boilers and Combined Cycle/HRSGs

Hydrogen damage (HD) is the most frequently occurring of the Underdeposit Corrosion (UDC) mechanisms and remains prevalent in fossil plant boilers and combined cycle plants with Heat Recovery Steam Generators (HRSGs).

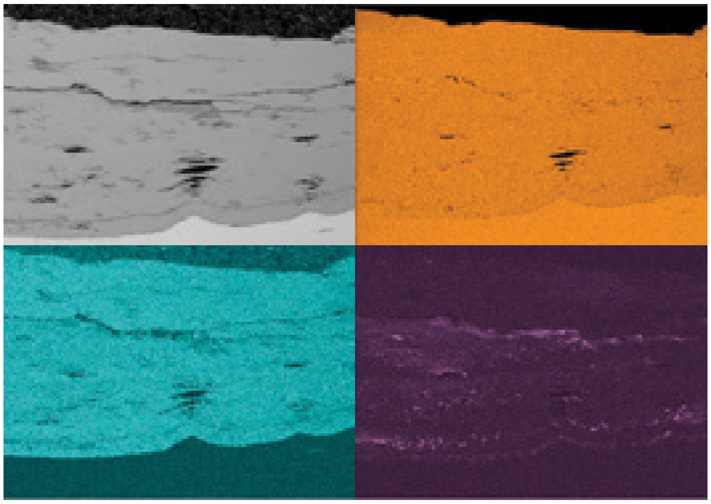
MECHANISM

Hydrogen damage requires a combination of heavy internal deposits and acidic contamination. The first step leading to damage is when excessive deposits are transferred and deposited in the boiler. If an acidic contaminant is introduced it can concentrate beneath the heavy internal deposits. The resulting acidic environment can affect the magnetite growth process. Magnetite will grow at the surface, break off, and then another layer starts to grow. This repetitive process produces a thick multilaminated oxide layer that grows at a quick rate and promotes further corrosion. Hydrogen generated by corrosion at the tube surface will react with the iron carbide (Fe3C) in the tube material to form methane (CH4). Because neither molecular hydrogen nor methane easily diffuse through the steel, the gases accumulate, primarily at the grain boundaries. Eventually, gas pressures will cause separation of the metal at grain boundaries, producing discontinuous intergranular separations (fissures). As fissures accumulate, tube strength decreases until tube stresses exceed the tensile strength of remaining intact tube metal. Tubes then fail in a brittle manner.


Window-Opening Rupture with internal gouging



Cross-sectional view of gouge with fissures at ID surface (unetched)


SEM image of ID Deposits (top left), EDS Iron Map (top right), EDS Oxygen Map (bottom left), EDS Chlorine Map (bottom right)

TYPICAL LOCATIONS

- ID surface of hot side of tubes
- Highest heat flux areas
- Near flow disruptors: joints, bends, improper welds, etc.

FEATURES

- Waterside mechanism
- Thick-edged failures, often window blowouts
- Gouging on ID surface
- Thick deposits within gouge (sometimes deposits are lost during failure)
- Chlorine concentrated at base of gouge
- Intergranular fissures in microstructure

ELECTRICAL PENETRATION ASSEMBLIES

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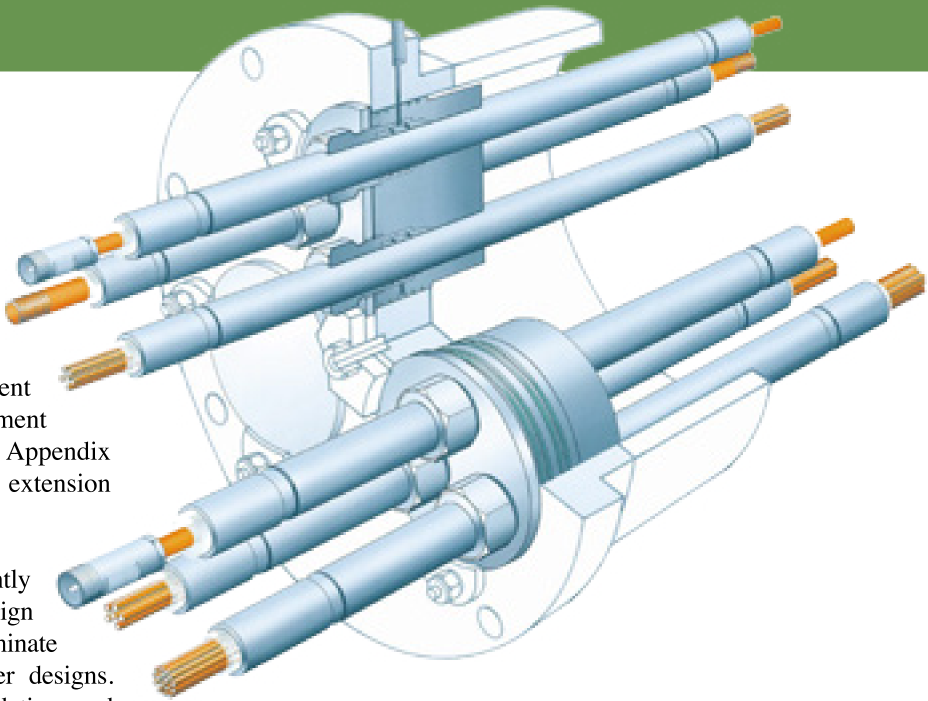
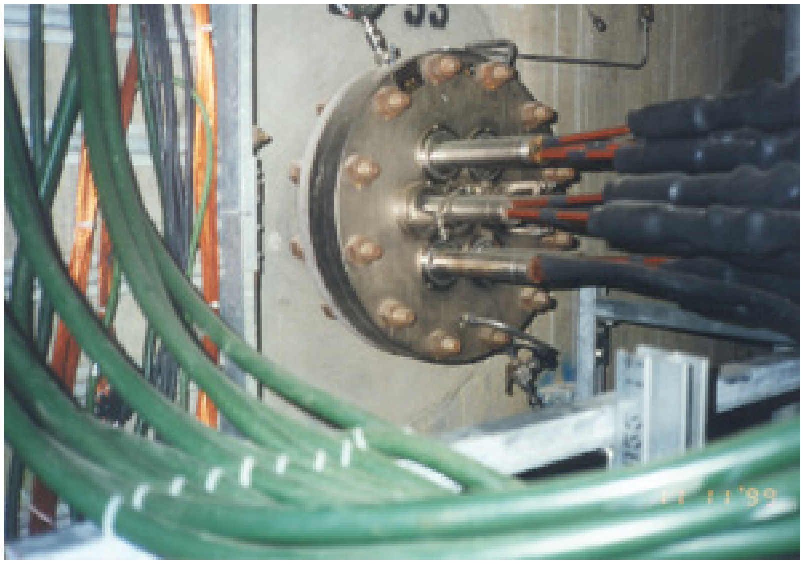


Electrical Penetration Assemblies (EPAs) that are classified as 1E (safety related electrical) provide a means of connecting electrical equipment inside primary containment to equipment outside containment while maintaining the safety barrier seal. Containment pressure boundary integrity is required per 10CFR50 Appendix J. Evaluation of EPA aging is required for plant life extension beyond 40 years of life.

The variety of electrical penetration assemblies currently being used in the nuclear industry reflects the results of design evolution. Current designs have evolved so as to eliminate features that were found to be problematic in earlier designs. EPA design features, mechanisms of age related degradation, and EPA electrical and sealing performance issues are documented in various industry reports. Effective methods of condition monitoring activities and corrective actions for these conditions have been developed. Lessons learned on craft workmanship and handling of sensitive subcomponents are also critical.

EPA condition in terms of leakage, electrical integrity, and criteria for determining acceptability are critical considerations. Performance data have been evaluated to help project EPA aging trends. The historical performance of the various types of EPAs with respect to both leakage and electrical performance provides a means to predict future performance and degradation. The effectiveness of the corrective actions and condition monitoring activities are also crucial areas of concern due to the expenses and schedule impact associated with replacement of EPAs whose performance is degraded.



Many of the early EPA designs were identified as having potential deficiencies in qualification or design vulnerabilities, leading to sealing or electrical issues, have been replaced with more modern designs that have enhanced design features. Specific maintenance and monitoring activities applicable to the individual EPA designs, based on specific failure/degradation modes applicable to each EPA type, can provide advanced indication of EPA performance degradation. Common modes of degradation that impact several EPA designs include epoxy potted EPA seals. Aging of epoxy potted seal barrier designs can potentially result in the development of leakage paths associated with agerelated potting shrinkage.

Electrical connection degradation issues can also exist. The more typical examples are as follows:

- Connection interfaces
- Internal connection deficiencies
- Wetting of feedthroughs due to mechanical sealing issues, especially impactful for bare conductors.
- Degradation of polyimide-insulated conductors.

Continued on next page

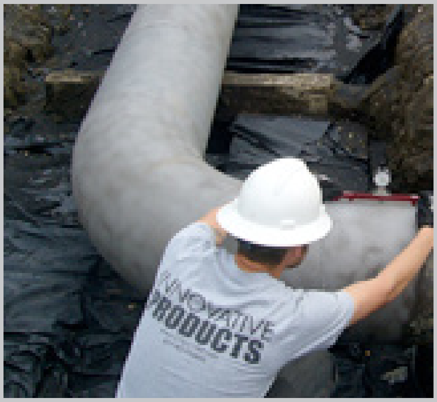
ELECTRICAL PENETRATION ASSEMBLIES CONTINUED

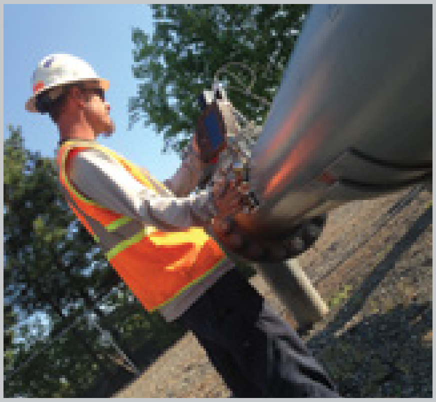
The prescribed 10CFR50 Appendix J LLRT (Category B) variable leak testing provides a means to track leakage performance. Most plants simply record and trend the leakage until one or more EPAs develop a leakage rate that shows either a significant increase over time or is leaking considerably more than other similar EPAs tested. For corrective maintenance purposes, plants should assume that EPA leakage will have a potential common-mode trend, even though the number of EPAs with significant leaks may be small. For EPAs, the leak rate trends do not tend to follow a linear progression. More commonly, EPAs exhibit a step-change in leakage rate, presenting challenges with respect to predicting aging trends.

Utilities are addressing leakage issues with EPA leak repair procedures typically using qualified sealants, with a smaller fraction considering EPA replacement (either feedthrough replacement or entire EPA replacement, depending on the design of the EPA).

For electrical performance issues, conduct of craft training activities that highlight the sensitivity of the polyimide insulation to physical manipulation of small gauge, low voltage pigtails of certain EPA designs to preclude handling damage is a potential approach to address the fragility of in these designs. Electrical performance of the electrical connections and feedthroughs can be assessed largely through existing programs such as plant cable aging management programs and/or testing of components further down line in the electrical circuit.

In summary, electrical penetration assemblies play an extremely vital part in supporting the primary containment boundary integrity (10CFR50 Appendix J requirements) and also provide electrical interfaces for the electrical and instrumentation equipment, located inside primary containment. Various designs are in service across the industry and some designs are more and others less susceptible to aging related degradation, either in the mechanical sealing or electrical performance, or possibly both. Replacement of EPAs can be capital intensive and impact outage performance. Cost effective repair alternatives exist for some designs to minimize overall life cycle costs. Programmatic performance monitoring of EPAs is recommended to permit proper planning and reduce the potential for extended outage time in addressing their performance.





OIL & GAS TRANSMISSION PAST AND UPCOMING TRAINING WORKSHOP AND CONFERENCE PRESENTATIONS

Structural Integrity is committed to supporting the oil and gas pipeline industry with a number of workshops and presentations in 2017:

Natural Gas Pipeline Safety Regulatory Compliance Workshop (February 14-16, Denver, CO, Bruce Paskett): A Comprehensive Review of Gas Pipeline Regulations (49 CFR, Parts 191 and 192) governing the design, construction, operation and maintenance of gas transmission and distribution pipelines.

2017 PRCI Research Exchange Meeting (February 21-22, Houston, TX): Structural Integrity was invited to present at the Pipeline Research Council International's (PRCI) Research Exchange Meeting, an annual meeting held to provide member companies, research partners, and external stakeholders with a report on the important research results and outcomes for completed projects and programs. The following topics were presented:

- **Insights on Pipeline Integrity Programs from the Nuclear Power Industry (Dr. Peter Riccardella):** This presentation summarized technical similarities and differences between nuclear plant components and buried gas pipelines in an attempt to provide insights that may assist the pipeline industry in developing more quantitative integrity management and MAOP verification programs in accordance with newly proposed revisions to 49 CFR Parts 191 and 192.
- **Performance and Application of Various In-the-Ditch Tools and their Impact on Pipeline (Scott Riccardella):** This presentation reviewed the NDE methodologies applied in two separate PRCI projects to evaluate SCC and ERW seam defects, test processes and protocols, crack truth verification processes, and analysis of the final results and resultant impact on pipeline integrity.

Pipeline Integrity and Corrosion Management Workshop (March 9, Gastonia, NC): Structural Integrity, along with MESA and EnhanceCo, are hosting a free one-day workshop for pipeline operators covering various best practices for pipeline integrity and corrosion management. Topics will include:

- **Review and Perspective Regarding the NPRM for Safety of Gas Transmission and Gathering Pipelines (Bruce Paskett)**
- **AC Stray Currents: Threat Assessment, Analysis and Modeling, and Remediation Best Practices (Presented by Charlie Hall and Randy Hodge)**
- **Crack Characterization and Evaluation (Scott Riccardella)**
- **Proper Planning, Dig Selection, and NDE Data Collection Tools and Reporting Best Practices for ILI Excavations (Charlie Hall and Scott Riccardella)**
- **Internal Corrosion Monitoring (Tom Pickthall)**

Southern Gas Association Spring Gas Exposition (March 13-15, Charlotte, NC):

- **Roundtable Update on New Regulation (Bruce Paskett)** Structural Integrity will be providing a brief presentation covering an update on the final pending proposed regulation for Safety of Gas Transmission and Gathering Pipelines.
- **AC Mitigation (Randy Hodge):** Structural Integrity will be providing a brief presentation on the threat assessment and mitigation of AC stray currents and their resultant impact on pipeline integrity.

NACE Corrosion 2017 (March 26-30, New Orleans, LA): We will be presenting the following papers at the 2017 annual corrosion conference and exposition:

- **C2017-8859 Strategic NDE Results Collaboration Yields Industry Insights (Steve Biagiotti):** This paper/presentation briefly discusses the U.S. nuclear buried pipe integrity program, the infrastructure created for information sharing, and the data mining results from more than 4,500 inspections on buried pipe at more than 60 sites in order to elicit thought provoking lessons for the pipeline industry.
- **C2017-9267 Using Portable Material Property Devices for Pipe Grade Determination (Steve Biagiotti):** This paper/presentation reviews in-situ techniques to measure pipe properties in lieu of other destructive approaches to meet the challenge within proposed regulation 49 CFR part 192.607(c) and recommends procedures to improve the repeatability and reliability of results.

American Gas Association (May 2-5, Orlando, FL): Structural Integrity will be presenting the following topics at American Gas Association's (AGA) operating conference, the major gathering for utility and transmission company operations management from across North America for technical knowledge sharing:

- **Material Verification: The Time to Start is Now (Bruce Paskett/Steve Biles):** This presentation will provide an overview of the material testing data for Integrity Management, including the value of fracture mechanics evaluation, flaw assessment, and MAOP verification. Suggested preliminary program structures will be presented, which would easily and naturally expand to the full Material Testing Program when the Safety of Gas Transmission Pipelines rule is finalized.
- **Exploring Engineering Critical Assessment (Bruce Paskett/Steve Biles):** This presentation will relate the proposed requirements of ECA to the fundamental engineering concepts behind establishment of MAOP. Possible implementation of proposed ECA requirements will be explored. The importance of choosing the correct application for ECA will be stressed.

FITNESS FOR SERVICE DETERMINATION FOR NON-RETURN VALVES IN A COMBINED CYCLE PLANT – A CASE STUDY

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A Fitness-for-Service (FFS) assessment is often a key exercise to support run/repair/replace decisions. If the assessment can show that the component can continue to operate safely for a significant period of time, costly replacements can be avoided or at least postponed. This article provides a case study of a recent FFS assessment for stop-check valves at a combined cycle plant. This case study provides background information, discusses the finite element analysis and fracture mechanics calculations performed, and finally provides conclusions and recommendations.

The FFS assessment was needed to evaluate cracking found during a field inspection for each of the three non-return valves at a combined cycle plant. It was recommended that more detailed analysis be performed to estimate crack growth rates and implications for remaining service life. The need was to evaluate unstable fracture and to estimate possible additional crack growth due to cyclic fatigue and long term creep at elevated temperature.

Based upon detailed numerical simulation and fracture mechanics calculations performed and Structural Integrity experience with similar valves, the mechanism of cracking present in the valve body adjacent to the guide rib was thermal fatigue. When subject to rapid temperature change, the relatively thick-walled valve body will respond slower to the temperature change than the internal cross member (guide rib) due primarily to the flow on both sides of the rib and its relatively small thickness compared to the valve body. This creates a temperature difference between the rib and the valve body, resulting in differential expansion and localized bending stress at the transition between the rib and the valve body. The largest thermal stresses are produced during the most rapid heating/cooling events which occur during start-up and at the very onset of cooldown events.

Summarized in this article is the information used in the analyses, the methods employed and the results. Conclusions and recommendations are also provided.

BACKGROUND

Original design data for the stop-check valves in the steam piping is provided below:

- Design pressure: 2080 psig
- Design temperature: 1085°F
- Operating temperature: 1050°F maximum
- Valve material: SA-217 Grade C12A (9Cr-1Mo-V-Nb cast)

Each of the three Heat Recovery Steam Generators (HRSGs) includes a 16-inch stop-check valve in the HP steam system. The valves are of identical geometry and comparable cracking was found in each valve. Dimensional information was used to develop Finite Element Analysis (FEA) models to simulate the valve thermal and structural response. Input was derived from design drawings, UT thickness data, and a 3D scanned image file provided by the valve manufacturer.

Visual examination of the ID of a typical valve identified linear indications on the bottom and top of the guide rib. The cracks were located on each end and both sides of the guide rib as shown in Figure 1.

PT examination verified the results of the visual inspection. The bleed-out from the cracks was extremely heavy and masked individual cracks indicating that the cracks were deep and/or wide. Cracks identified by PT were evaluated using Linear Phased Array (LPA) to determine the maximum crack depth along the length of the indication. The full length of the cracks on the bottom end of the guide rib were scanned, however the cracks on the top of the guide rib were scanned from the bore side only due to the inaccessibility and surface roughness in the top bore area. The largest crack depth on the bottom was 0.55" deep while at the top was 1.4".

For the analysis of the valve it was necessary to establish the typical steady state loading as well as any significant load fluctuations that may contribute to crack growth. Structural Integrity's experience with similar valves indicates that the primary mechanism of cracking is thermal fatigue due to start-up/shutdown cycles and possibly other significant temperature cycles. The important operating parameters that affect thermal fatigue are the frequency and severity of the temperature fluctuations.

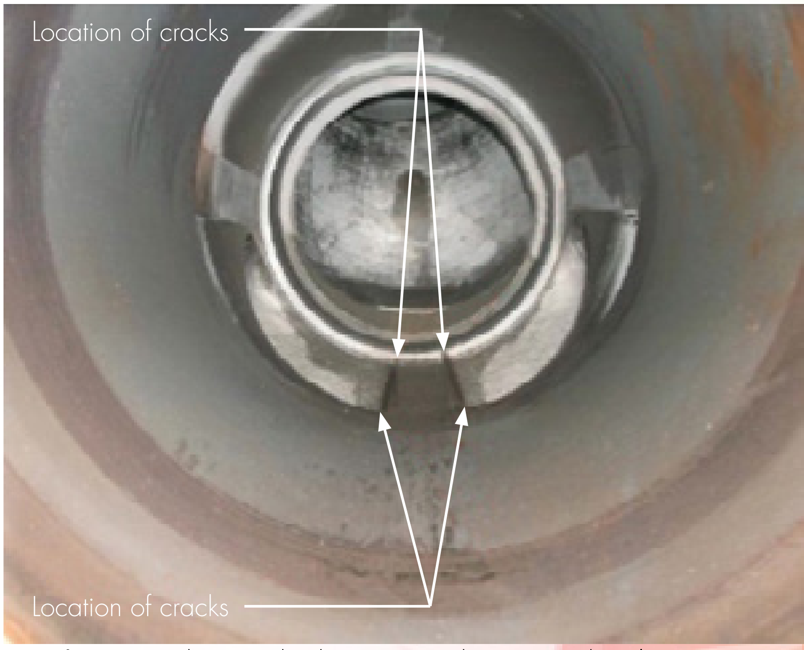

Figure 1. Photographs showing PT indications on the inlet (upstream) and outlet (downstream) of the valve seat

Rates of temperature change were investigated for severity. Rates less than 100F/hr are not typically severe and do not lead to significant thermal gradients and stress in the valve. Rates that exceed approximately 1000°F/hr result in much more significant thermal gradients and higher stresses. Rates on the order of 3000°F/hr result in thermal/mechanical response that approaches an instantaneous step change in temperature, which is the bounding gradient case for a thermal shock.

ANALYSIS METHODS

A two-dimensional (2D) FEA model was used to simulate the thermal/mechanical response of the valve. Comparative 3D solid modeling was performed to validate this approach. Furthermore, the cracks were modeled explicitly in order to directly determine the crack tip driving force (also known as stress intensity factor and denoted as "K") for use in subsequent crack growth calculations. A range of crack depths were analyzed to determine the stress intensity factors for various crack depths of concern (allowing subsequent calculation of crack growth by interpolation of stress intensity factor as a function of crack depth). Crack depths of 0.125, 0.375, 0.60, 1.0, 1.5, 2.0 and 2.6 inches were analyzed. Heat transfer and thermal-mechanical (temperature and pressure) stress analysis are performed together using a coupled-temperature displacement FEA approach. At various instants during the event being analyzed (e.g. start-up),

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FITNESS FOR SERVICE DETERMINATION FOR NON-RETURN VALVES IN A COMBINED CYCLE PLANT – A CASE STUDY CONTINUED

the temperature distribution and the associated stresses and K values are determined due to the combined effects of temperature gradients and internal pressure.

Stress contour plots, highlighting hoop stress (crack opening stress direction) for internal pressure, start-up and thermal downshock were generated, with Figures 2 and 3 showing examples. Note that the magnitude of elastic stress at the crack tip is not relevant, since the crack tip driving force is calculated directly using a typical J-Integral approach and is provided as output (stress intensity factor) by the finite element analysis software.

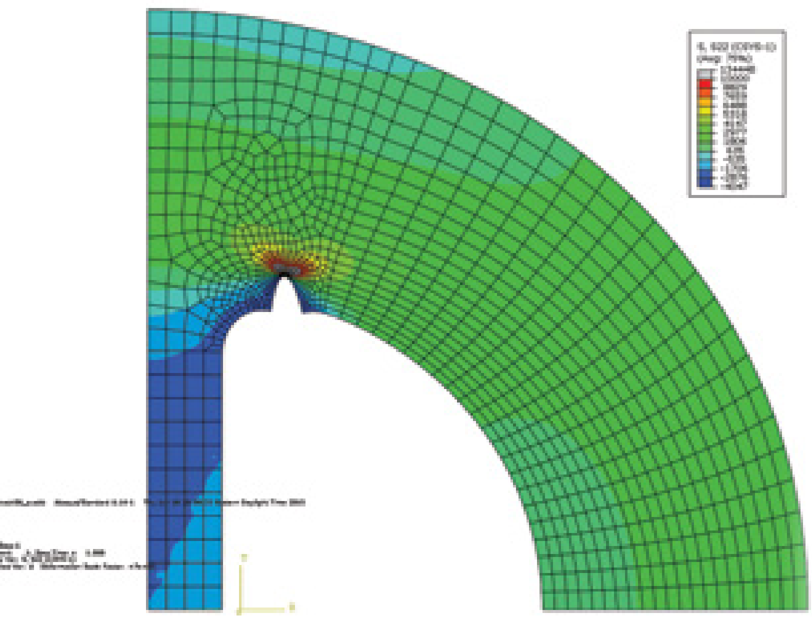

Figure 2. Hoop stress for internal pressure and crack face pressure of 2000 psig for 0.6 inch deep crack

FRACTURE MECHANICS EVALUATION

Fracture mechanics calculations were performed to determine the critical flaw size considering the failure modes of unstable fracture and plastic collapse. The calculations were performed in accordance with the methodology outlined in Part 9 (Assessment of Crack-Like Flaws) of API 579, using the Failure Assessment Diagram (FAD) methodology.

A known flaw that is suitable for service (i.e., less than the critical crack size) at one inspection may subsequently grow during the operating period until the next inspection. It is therefore necessary to account for this potential flaw growth when dispositioning detected defects (i.e., run vs. repair) and

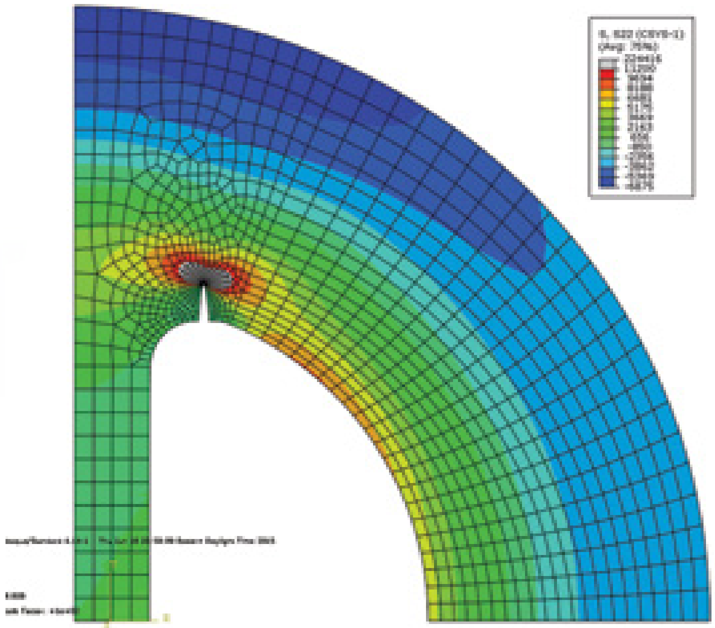

Figure 3. Max. hoop stress during 100°F downshock for 0.6 inch deep crack

establishing safe operating or re-inspection intervals as part of a fitness-for-service assessment approach.

The results indicate substantial margin relative to the FAD envelope for a 0.6 inch deep flaw in the bottom portion of the valve. The cracks in the upper portion of the valve were less limiting based on the amount of material present. Note that a lower bound toughness was used for the analysis. The critical flaw size was calculated and resulted in a through wall crack depth of 2.6 inches, indicating substantial margin relative to the current flaw depths.

FATIGUE CRACK GROWTH

To estimate the future rate of growth of the existing cracks and to assess inspection frequency, calculations were performed considering cyclic stresses and crack tip stress intensity factors calculated during operation. The frequency and severity of these cycles affect the rate of future crack growth.

Based on review of the operating data, the cold and warm start-up/shutdown cycles were the dominant contributors to fatigue crack growth. The frequency and magnitude of smaller fluctuations in pressure and temperature during operation were considered typical and would not be expected to have a significant contribution to crack growth.
The fatigue crack growth analyses were performed using the pc-CRACK software developed by Structural Integrity. The software

allows for definition of loading blocks, which can be used to define and combine various cyclic loading events during a specified operating period. Based on review of the operating data, a loading block representative of typical operation was specified. The material fatigue crack growth law used in the analysis was that given in API 579 for ferritic and austenitic steels exposed to non-aggressive service environments at temperatures between 100ºC (212°F) and 600ºC (1112°F). Results of the fatigue crack growth calculations indicate that if the plant continues to operate similar in the future as it has in the past, the cracks are not predicted to grow to the critical length of 2.6" for more than 2500 cycles or about 25 years of operation.

CREEP CRACK GROWTH

The valves are required to operate at high temperature (up to 1050°F) which is in the creep range for the C12A (Grade 91) material. Specifically, at such temperatures the long-term application of internal pressure can potentially result in creep damage. The time to creep failure is strongly influenced by the operating temperature and stress. The creep crack growth calculations were performed in accordance with Part 10 of API 579 and Structural Integrity Standard Operating Practices (SOPs).

Inputs to the assessment include component and crack geometry, operating conditions, applied stresses and material properties. Creep crack growth is based on a standard Paris law-like power law equation, but is based on the C* or Ct parameter rather than the K parameter for fatigue crack growth. The required creep crack growth constants are documented in our SOPs, and similar data is also included in API 579.

The detailed calculations are not provided here, but the time computed (remaining life) from creep crack growth analysis, for a 0.6 inch initial crack to grow to a 2.6 inch critical flaw depth is significantly large (millions of hours). The large thickness of the valve body translates to low pressure induced stresses to drive creep damage. Therefore, creep crack growth was not considered a significant factor affecting remaining life of the valves.

SUMMARY

The FFS assessment indicated that the cracks identified do not appear to be an immediate threat to the operability of the valves, and future service can be realized with occasional inspections to verify that the cracks are not growing faster than predicted. The cracks are predicted to continue to grow as additional operational cycles are accumulated; however, that growth is predicted to occur at a relatively slow rate, and the rate decreases with crack depth due to decreased thermal stress away from the internal surface.

Based on the results of this analysis and Structural Integrity experience with similar valves, it was recommended to perform a follow-up inspection at the next scheduled opportunity (within the next three years) to measure crack depth to help verify predictions and provide some protection in the event that some cracking mechanism (e.g., environmental) or temperature excursions not considered in the predictions might be actively contributing to crack growth. Results of an inspection of this type should be carefully recorded to allow comparison of crack locations, surface lengths and depths between subsequent inspections.

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NACE Corrosion 2017
Orleans, LA *March 26 - 30*, Exhibiting and Presenting

American Gas Association
Orlando, FL *May 2 - 5*, Presenting

NAES Operations and Maintenance Managers Conference
San Antonio, TX *May 15 - 19*, Exhibiting and Presenting

NEI NEA 64th Annual Industry Conference and Supplier Expo
Scottsdale, AZ *May 22 - 24*, Exhibiting

Cycle Chemistry and FAC Training
Cincinnati, OH *June 27 - 28*, Presenting

ANS Utility Working Conference & Vendor Technology Expo Amelia Island, FL *August 6 - 9*, Exhibiting

AEP Bro Forum
Columbus, OH *August 7 - 10*, Exhibiting

NPFA - Nuclear Plant Fatigue Applications
Asheville, NC *August 21 - 24*, Presenting and Sponsoring

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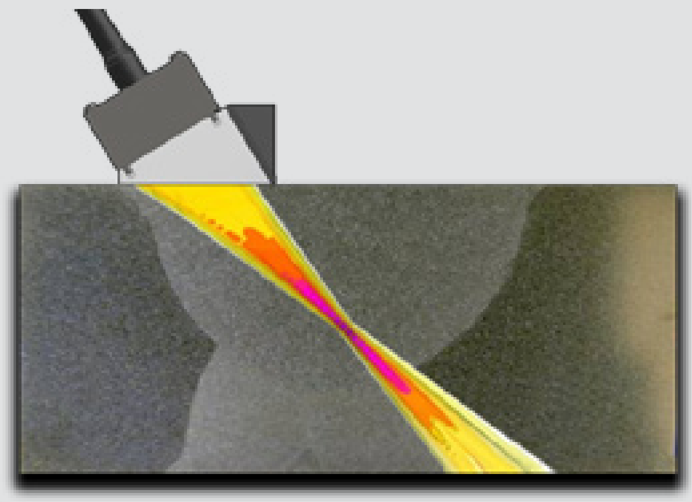

DID YOU KNOW?

Our engineered ultrasonic services exploit our acoustic modeling expertise and customized technology to maximize creep damage detection and characterization. We have recently made enhancements to our ultrasonic phased array technology to improve signal fidelity and increase sensitivity to service damage that can occur in weld and base metals.

ENHANCEMENTS TO OUR ANNULAR PHASED ARRAY TECHNOLOGY

- Advanced ultrasonic simulations
- Improved signal to noise ratio
- Improved sensitivity
- Redesigned scanner technology
- Increased deployment efficiency

Our Annual Phased Array (APA) technology has come a long way since it was originally proven for detection of early stage creep damage in the seam-weld research of the 1990s. With the recent enhancements, which will be described further in a future N&Vs issue, we continue to set the standard for early detection of service damage. That provides more time to manage damage and avoids having to make reactive repairs when damage is first discovered.