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Proceedings: International Conference on Boiler Tube and HRSG Tube Failures and Inspections

November 2–5, 2004

Technical Report

Proceedings: International Conference on Boiler Tube and HRSG Tube Failures and Inspections

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PRODUCT DESCRIPTION

Tube failures are the leading cause of availability loss in conventional fossil plants and combined cycle/heat recovery steam generator (HRSG) plants. This conference proceedings addresses worldwide state-of-the-art practices and techniques for understanding and reducing tube failures.

Results and Findings

This proceedings contains the papers and survey results from the 2004 conference. Some key points of these findings are:

- The leading causes of boiler tube failures (BTF) in conventional fossil plants are flyash erosion, corrosion fatigue, longterm overheating/creep, sootblower erosion, and under-deposit corrosion.
- The leading causes of HRSG tube failures (HTF) are flow-accelerated corrosion, thermal fatigue, corrosion fatigue, and under-deposit corrosion.
- Over 75% of conventional fossil plants experience corrosion-influenced BTF. Hydrogen damage remains the most prevalent form of BTF.
- Over 80% of organizations have management-supported BTF reduction programs, but only about 70% address BTF to the root cause level.
- The primary areas that are in need of further research are optimum approaches for corrosion fatigue, nondestructive evaluation (NDE) techniques for corrosion fatigue and hydrogen damage, and solutions for supercritical waterwall thermal fatigue cracking.

Challenges and Objectives

In conventional fossil plants, the availability loss due to BTF in the United States is approximately 3% and has increased annually from a minimum of 2.5% in 1991. Similar deteriorating trends have been experienced around the world. BTF influenced by cycle chemistry have been increasing since the BTF conference in 1997 (*Proceedings: Third International Conference on Boiler Tube Failures in Fossil Plants* – EPRI report TR-109938). There are no comprehensive statistics for HRSGs, but cycle chemistry–influenced HTF represents over 70% of the total. This was the second international conference at which tube failures in both types of plants were discussed at the same time. The objectives of the conference were to evaluate and exchange technical information on established BTF and HTF analysis, the prevention of these failures, and to increase the understanding of conventional and combined cycle/HRSG power plants.

Applications, Value, and Use

The conference discussions are applicable to all BTF and HTF mechanisms that occur worldwide.

EPRI Perspective

The BTF/HTF conferences, held every three years, provide an excellent perspective on the leading causes of availability loss in fossil and HRSG plants. The survey results help drive the needed research. Subsequent to this conference, EPRI initiated large projects on corrosion and thermal fatigue, and is currently developing a concentrated approach of NDE for hydrogen damage and corrosion fatigue. Work has also been started on a radically new approach for NDE and repair of HRSG tubes from inside the tubing.

Approach

EPRI sponsored the international conference on BTF and HTF in San Diego, California, on November 2–5, 2004. The 39 presentations focused on leading failure mechanisms, cycle chemistry, NDE, remaining life, and BTF/HTF reduction programs. In addition, EPRI conducted a survey of conference participants concerning their experiences with BTF and HTF and on possible future research and development topics.

Keywords

Plant availability
Boilers
HRSGs
Tubes
Failures
Corrosion

ABSTRACT

EPRI sponsored the International Conference on Boiler Tube and HRSG Tube Failures in San Diego, California, November 2–5, 2004. The 39 presentations focused on leading failure mechanisms, cycle chemistry, nondestructive evaluation (NDE), remaining life, and boiler tube failure (BTF)/HRSG tube failure (HTF) reduction programs. EPRI also conducted a survey of participants concerning their experiences with BTF and HTF and on possible future research and development topics. The survey results are included in these proceedings.

ACKNOWLEDGMENTS

This conference was sponsored by EPRI. Special thanks to Richard Tilley (co-chairman) and to the individual authors, presenters, and session chairmen.

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PLENARY SESSION

Chairman: R. Tilley, EPRI

Tube Failures in Conventional Fossil Fired Boilers and in Combined Cycle/HRSGs

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1.0 Introduction: "Current Approaches Lead to Failure, Large Availability Loss and Enormous Costs"

Tube failures in both conventional and combined cycle/HRSG plants continue as the number one problem of forced outage and availability loss in their respective plants. While there are no overall statistics for HRSGs in combined cycles, boiler tube failures (BTF) in conventional plants account for between 2.5 and 3.0% availability loss. The most recent ranking of BTF mechanisms in fossil plants is provided in Table 1[(1)(2)].

Table 1. Compilation of the Leading BTF Mechanisms from Surveys Conducted at the 2003 Cycle Chemistry[(1)] and the 2001 BTF/HTF Conferences[(2)]. An outline of the optimum approach for each BTF mechanism is also included.

Ranking of BTF Mechanisms	Optimum Approach
1. Corrosion Fatigue on Waterwalls of Subcritical Boilers	Requires monitoring of temperature and strain at attachment sites. NDE requires two levels: initial internal inspection or radiography plus detailed assessment of cracks.
2. Longterm Overheating/Creep in Superheaters and Reheaters	Application of steamside oxide scale thickness following gas-touched length analysis.
3. Fly Ash Erosion	Cold air velocity technique plus installation of diffusion and distribution screens.
4. Sootblower Erosion	Improved maintenance on sootblowers on an as-needed, rather than a regular, basis.
5. Under-deposit Corrosion on waterwalls of subcritical boilers a) Hydrogen damage b) Acid phosphate corrosion c) Caustic gouging	Improved cycle chemistry of feedwater and boiler water to minimize feedwater corrosion products. Instrumentation to identify contaminant ingress. Improved air in-leakage.

One of the top three mechanisms in Table 1 is usually the leading cause of failure in individual organizations around the world, and these mechanisms have remained

essentially constant over the last 30 years. The other disturbing aspects are that the number of repeat failures (same boiler, same circuit, same mechanism and root cause) remain very high (above 70%), and that the cycle chemistry influences remain high (20-50%). The under-deposit mechanisms continue unabated with hydrogen damage occurring in close to 60% of drum units[(1)(2)].

As well as these most important mechanisms there are a couple of other mechanisms which are encroaching on the top ten. Short term overheating is occurring, and has occurred, in the superheaters of most boilers that have austenitic tubing due to the large amounts of steamside oxide exfoliation during shutdown, which leads to tube blockage during startup. The other mechanism relates to fireside corrosion of waterwalls on units with heavily staged combustion and retrofitting of low NOx systems. This problem first appeared on supercritical units but is now appearing on subcritical boilers. The only solution which appears to provide some alleviation is weld overlay with one of a variety of high chromium materials (309, IN625, chromizing, etc.). Now that these have been applied for nearly 10 years a new series of questions and concerns are emanating:

- cracking of the overlay
- life of the overlay
- NDE of overlayed tubing (Section 4.3)
- Internal, under-deposit corrosion when the overlay is applied incorrectly to sub-critical waterwalls.

In the HRSG world a similar ranking of mechanisms has been generated by EPRI with a concentration for the multi-pressure units. The primary locations and failure mechanisms are shown in Tables 2 and 3.

Table 2. HRSG Tube Failure Experience by Circuit[(1)(2)]

• **Have you Experienced HTF**	**60%**		
LP Evaporator	# 1	HP Evaporator	# 5
Superheater	# 1	IP Evaporator	# 6
LP Economizer	# 3	IP Economizer	0%
HP Economizer	# 3	Reheater	0%
• **FAC in LP Drum**	**26%**		
• **FAC in LP Evaporator Tubing**	**26%**		

Table 3. Compilation of the Leading HTF Mechanisms from Surveys Conducted at the 2003 Cycle Chemistry[1] and the 2001 BTF/HTF Conference[2]. An outline of the optimum approach for each HTF mechanism is also included.

Ranking of HTF Mechanisms	Optimum Approach
1. Thermal Fatigue (includes Creep-Fatigue)	Requires temperature monitoring of key circuits.
2. Flow-accelerated Corrosion	Elimination of reducing agents in feedwater and optimization of LP evaporator chemistry.
3. Corrosion Fatigue	Requires same monitoring as for 1 as well as monitoring and optimization of cycle chemistry to eliminate pH transients in evaporator circuits.
4. Under-deposit Corrosion in HP Evaporators a) Hydrogen damage b) Acid phosphate corrosion c) Caustic gouging	Requires same approach as under-deposit mechanisms for conventional plants (Table 1).
5. Pitting	Shutdown and Layup protection.

Comparison of Table 3 with Table 1 shows a similar suite of failure mechanisms. Fatigue mechanisms play a much more important part in HRSGs because of the very large thermal transients that can be experienced[3][4]. Also flow-accelerated corrosion (FAC) BTF only occur at the economizer inlet header tubes in conventional plants, but is a major HTF mechanism in low pressure economizer and evaporator circuits of HRSGs. But even more important than the actual failures in HRSGs is that if FAC is allowed to continue then the generation of increased iron levels in the cycle causes concern due to increased deposits and the possibility of under-deposit corrosion mechanisms in the HP evaporator circuits.

While the suites of failure mechanisms are similar, and because the organizations that operate these plants have basically the same staff backgrounds, the authors find that the approaches being used are similar and involve:

- not identifying the mechanism and root cause adequately
- mixing up the mechanism and root cause
- not addressing the root cause to kill the mechanism
- not applying known solutions and optimum approaches[5]
- not applying current best practices for remaining life for each BTF/HTF mechanism
- not being proactive or predictive, and

quite simply "waiting for the BTF/HTF to occur" appears to be the modus operandi.

Although there is an almost complete understanding of the mechanisms and possible root causes for each of the mechanisms in Tables 1 and 3, the different ages of the basic

technologies (50 years for conventional and about 15 for HRSGs) demand different approaches and philosophies. For HRSGs, the message must be to first identify as early as possible the thermal and cycle chemistry transients, and secondly to correct and optimize them to reduce the possibility of initial failure. For conventional boilers, the approach needs to change from "waiting for failure" to first ensuring that the mechanism and root cause for each possible BTF mechanism is understood, and secondly, that remaining life methodologies are applied for each mechanism.

2.0 Tube Failures can be Beaten or Prevented

2.1 Conventional Fossil Boilers

Ample results are now available[6] to illustrate how an organization should approach an orderly, corporate supported, multidisciplinary BTF reduction program. It is very clear that BTF and HTF cannot be addressed from purely a technical viewpoint. It is equally clear that the day has passed when individuals (such as the corporate metallurgist), specific sections (maintenance), outside consulting companies or the OEM can provide the needed total advice and guidance. Another approach by a number of organizations has been to aggressively reduce the mean time to repair (MTTR) to address the shorterm aspects of availability loss due to BTF, rather than to address the root cause to achieve longterm benefits.

None of these approaches has been shown (anywhere in the world to the authors' knowledge) to consistently reduce availability loss and associated costs in the same way that have emanated from EPRI's BTFRP/CCIP over the last seven years[6][7]. During this time period, EPRI has conducted this program with over 60 organizations worldwide and benchmarked over 100 organizations for BTFR and CCI. Table 4 provides a sprinkling of the results from a number of case studies, some of which were originally published in 2003[6]. The table shows the improvements that have been made in equivalent availability loss (EAL) due to BTF and the Benchmark scores for boiler tube failure reduction and cycle chemistry improvement[6]. Each organization was benchmarked at least once per year during the program, and each benchmark score can provide the value of the improvements[6].

While Table 4 only provides information on six organizations, the overall EPRI program has been applied and shown to work in a wide range of plants (coal, gas, oil, subcritical and supercritical), operating conditions (base load, cycling, two shifting), age (new to over fifty years old), and availability (<1% availability loss due to BTF to >5%).

Table 4. Six Case Studies from EPRI's BTFRP/CCIP

Case Study	A	B	C	D	E	F
Size of Organization (MW)	15,000	1,200	34,000	4,300	1,400	980
Number of Plants (Units)	11 (58)	1 (2)	10 (64)	7 (17)	1 (4)	1 (2)
Initial EAL % (date)	3.4 (2000)	2.13 (2000)	1.2 (1997)	2.4 (2000)	0.98 (2000)	3.8 (2002
Latest EAL % (date)	2.1 (2003)	0.95 (2003)	0.8 (2003)	1.7 (2003)	0 (2003)	1.5 (2003)
Initial BTF Benchmark (date)	20 (2000)	14 (2000)	13 (1997)	23 (2000)	10 (2000)	23 (2002)
Latest BTF Benchmark (date)	13 (2003)	5 (2003)	6 (2003)	17 (2002)	7 (2003)	8 (2004)
Initial CCI Benchmark (date)		14 (2000)	11 (1999)		7 (2002)	22 (2002)
Latest CCI Benchmark (date)		5 (2003)	6 (2003)	9-3 (2002)	5 (2004)	11 (2004)

BTF Benchmarks: World Class 0-5, Very Good 6-10, Good 11-15, Average 16-20, Below Average >20
CCI Benchmarks: World Class 0-5, Very Good 6-10, Good 11-15, Average 16-30, Below Average >30
EAL is equivalent availability loss and is the total of EFOR and EMOR

2.2 Combined Cycle/HRSG Plants

The more juvenile nature of HRSGs and the smaller number of plant personnel demands a slightly different approach to the BTFRP/CCIP used for conventional plants. In the HRSG arena, EPRI has developed an HRSG tube failure reduction/cycle chemistry improvement program (HTFRP/CCIP) which is also directed multidisciplinary but is primarily aimed at identifying those processes (chemical and thermal transients, and cycle chemistry optimization) which are known to influence the top HTF mechanisms (Table 3).

For example, on the chemistry side it is most important to eliminate those features which have been "built in" to cause failure from the specification and design phases. Table 5 shows that a high proportion of multi-pressure systems still add a reducing agent to the feedwater, when it is well understood that with low air in-leakage in the newer combined cycle plants the addition will produce a reducing feedwater which engenders FAC in the feedwater and low pressure economizer and evaporator circuits. This can be easily identified by a monitoring campaign to measure iron in the feedwater and at each drum.

Table 5. Chemical Treatments of HRSGs (Survey at 2003 International Conference[1])

	AVT	TSP (only)	Phosphate Blend	CT
LP Drum	48%	25%	11%	
IP drum	22%	22%	11%	1%
HP Drum	26%	30%	15%	1%

Reducing Agent in Feedwater: 63%

On the thermal side it is equally important to identify those features which could lead to large thermal transients. Table 6 provides some examples[8].

Table 6. Examples of thermal-mechanical loads in HRSGs which without identification and correction will lead to thermal fatigue or creep-fatigue HTF

• Thermal shock of header boreholes • Local tube-to-header discontinuity stress due to the midwall tube temperature being different than the header • Local thermal/pressure discontinuity stress at drum/downcomer nozzle connections • Global constrained thermal expansion due to tube row temperature differences, and "pant leg" tube design, exacerbated by "dog leg" bends at headers • Global constrained thermal expansion due to tube row temperature differences, and "pantleg" header/manifold piping design • Global constrained thermal expansion due to tube row temperature differences, and economizer design with restrained thermal expansion • Global constrained thermal expansion due to tube element temperature differences caused by cooling of selected tubes by forward flow of undrained condensate or excessive or poorly distributed attemperator water • Global constrained thermal expansion due to tube element temperature differences caused by steaming in selected tubes • Global constrained thermal expansion due to tube row alloy differences • Global constrained thermal expansion due to restrained thermal expansion of piping causing header rotation

3.0 Tube Failure Mechanisms in Boilers and HRSGs

The surveys at previous BTF/HTF conferences[(1)(2)] have indicated general satisfaction with tube failure mechanistic understanding. However, the statistics, Tables 1 and 3, do not support that this understanding flows down to the bottom line: overall reduction of repeat failures. Thus it is worth reiterating here some of the key approaches for the leading mechanisms, and these are also included on Tables 1 and 3 in outline form.

3.1 Corrosion Fatigue

Corrosion fatigue is a discontinuous process in that initiation and propagation (or repetitive initiation) only occurs during certain operating ranges (early startup and during severe shutdowns such as force cooling) which generate sufficient strain (>0.2%) on the tube internal diameter to crack the magnetite[(9-13)]. The boiler water or HRSG evaporator water can influence this process (pH transients)[(14)(15)]. Thus to identify the root cause it becomes necessary to concurrently monitoring the strain, temperature and cycle chemistry[(16)] during all typical operating regimes. In an HRSG, the same thermal monitoring required to identify thermal-/creep-fatigue needs to be conducted. Without these processes, an organization has no way of assessing the efficacy of any solutions. But most often organizations simply replace tubes with modified or similar attachment designs and make no attempt to improve the cycle chemistry. The search is still on for the elusive reliable NDE tool that can not only locate, but also size, corrosion fatigue cracks (see Section 4.3).

3.2 Longterm Overheating/Creep in Superheaters and Reheaters

Surveys and the EPRI benchmarking process indicate that less than 50% of superheaters and reheaters in conventional plants have been assessed by the internal steamside oxide thickness technique. Organizations still seem to prefer to wait for failure to indicate a problem despite the fact that overheating can be identified from first operation using the "gas-touched-length" method as a level one assessment[5].

A new technique is also available to assess austenitic materials using a creep void and sigma phase counting algorithm[17].

3.3 Fly Ash Erosion

The Cold Air Velocity Technique (CAVT) and the associated design and installation of diffusion and distribution screens remains the most successful technique to overcome fly ash erosion[18][19]. A recent project on a 500MW NTPC plant in India burning about a 40% ash coal has again demonstrated the efficacy of the technique[20].

3.4 Hydrogen Damage in Conventional Boilers and High Pressure HRSG Evaporators

In conventional drum boilers, hydrogen damage failures are perhaps at an all-time high around the world but especially in the U.S. As hydrogen damage cannot occur without excessive local deposits[5], the current experience indicates that too few organizations take the time to select and optimize the plant feedwater treatment, leaving the corrosion product transport levels in excess of EPRI Guideline values and also above those known to be easily achievable by "Very Good" and "Worldclass" units. Lack of instrumentation, together with inadequate boiler water contaminant control curves (chloride and sulfate), and operators who "don't know what to do under contaminant situations" usually complete the picture leading to hydrogen damage.

In HRSGs, the excessive corrosion products in the HP evaporator tubes emanate from the lack of control of corrosion and FAC in the feedwater and LP economizer and evaporator circuits (Section 3.6).

For both types of plants, use of an expert system or advisor (ChemExpert or CC ChemExpert) provides instant advice and guidance to the operators. But EPRI's experience in developing these systems over the last 10 years indicates a marked lack of enthusiasm by the operators and chemists.

3.5 Thermal- and Creep-Fatigue in HRSGs

It is now well documented that the designs of most HRSGs do not include comprehensive fatigue analysis of either the LP water-touched circuits or the HP steam circuits. This is basically because most of the design codes around the world do not "require or include it"[3][4]. A number of manufacturers do include some level of analysis if pressed by the operator, architect-engineer, or EPC contractor. To address these

situations and to identify future possible HTF early, it is imperative that the owner/operator conducts extensive thermal monitoring to address the possible thermal-mechanical loads such as delineated in Table 5.

3.6 Flow-accelerated Corrosion (FAC) in HRSGs

FAC is well understood and addressed in conventional plant feedwater systems because of the possibility of safety and fatality issues[21-23]. In HRSGs, FAC should be regarded as not only a possible HTF situation but also THE major generator of corrosion products. Single phase FAC in feedwater, and LP economizer and evaporator circuits should be addressed by non-use of reducing agents in the feedwater to ensure the fluid is oxidizing (oxidizing-reducing potential, ORP, greater than zero)[4][24][25]. Table 4 indicates however that over 60% of HRSG operators still use a reducing agent. The two-phase version of FAC occurring in LP evaporator circuits and LP drums needs to be addressed by optimizing the chemistry and/or by material changes (use of higher chromium containing materials). The optimum chemistry options include use of a solid alkali (tri-sodium phosphate or NaOH) in the LP drums. This option cannot be used, however, if the LP circuit provides feed for the higher pressure circuits or attemperation[25].

4.0 NDE Issues for Boiler and HRS Tubing

Non-destructive evaluation (NDE) provides a reality check on the actual condition of plant components over time. Variations in component design, materials, and operating conditions make it very difficult to accurately predict component life via analytical models. Inspections are used to detect the onset of damage and to refine the remaining life estimates of components. Accordingly, NDE is a key element in a practical life management approach for boiler and HRSG tubing. Where utilities perform periodic inspections of tubing and use the inspection results to refine estimates of remaining life, such utilities are successful in avoiding in-service tube failures.

Further, in the EPRI recommended process (BTFRP/CCIP)[6][7][26] for addressing boiler tube failures, a key, and frequently ignored, step is to determine the extent of damaged tubing due to an active failure mechanism. When this inspection step is skipped, the risk of repeat tube failures and corresponding forced outages is high. Utilities that identify damaged tubing early in life, and tubing subject to the same failure mechanism and that replace or repair such tubes are able to avoid serious repeat tube failures.

Although most tubing NDE work is performed during planned maintenance outages, it is important to note that NDE actions should also be considered during forced outages caused by tube failures. As presented above, the ability to identify damaged tubing early is critical in allowing the utility to avoid future tube failures. The challenges today are to have suitable inspection techniques available to cost-effectively detect boiler tube damage under both planned and unplanned outage scenarios. The

following sections provide a review of current NDE issues for boiler tubing in conventional fossil plants and in heat recovery steam generators.

4.1 The Good

Where inspections are conducted and results evaluated in the context of component remaining life, in-service boiler tube failures are avoided. Importantly, many organizations have increased their inspection efforts as a result of implementing a formal program to reduce tube failure rates per EPRI recommendations[7]. A key driver for this change is the benchmarking item for remaining life assessment of superheater and reheater tubing. This item mandates inspections and data evaluations for these components that are subject to creep degradation over time and that have finite service life (see Section 3.2). Such life assessment efforts are critical to avoiding a series of in-service failures early in life or as these tube sections approach end of life.

Additionally, low cost, digital, ultrasonic, thickness gages are becoming routine equipment for maintenance staff and are being used during both planned and forced outages to assess damage to tubing due to corrosion and erosion processes. Along with visual inspection, this technology represents the most common form of tubing inspection. Detection and repair of damaged tubing provides the best short-term assurance of reducing future tube failures. Correction of the root cause of the failure mechanism then provides the basis for longterm reliability by eliminating future tube damage.

An important facet of NDE is the development of more options for surveying large areas in the boiler. These technologies generally trade-off some level of detection accuracy for improvements in coverage by offering faster inspections or requiring less surface preparation for inspection. Technologies such as electromagnetic acoustic transducers (EMATs), active infrared (IR) scanning, mutual inductance bridge (MIB) testing, and lamb wave inspections are a few of the newer options available to address damage detection

Finally, the inspection process is frequently limited by the difficulty in accessing the area to be inspected. Accordingly, EPRI and others have initiated projects to develop robotic platforms to carry inspection equipment into areas not easily accessible by human operators. These inspection robots may be as simple as magnetic wheeled crawlers that can transport sensors into tubing pendants or may involve more articulated components capable of positioning NDE systems in remote or difficult geometry areas of a boiler. Figure 1 shows a robotic device under development for potential use on waterwall surfaces. The domed area contains a video camera, while the left side arm holds an eddy current sensor and the right arm is a tube surface cleaning device.

Figure 1. Magnetic Crawler for Use on Waterwall Surfaces

4.2 The Bad

Although progress is being made in performing more inspections as part of tube failure reduction efforts, it is important to emphasize that inspections alone are not always the appropriate way in which to address tube damage. A specific case concerns the increasing rates of hydrogen damage being reported in the industry[(2)(27)]. This damage mechanism has been fully researched by EPRI[(5)] and involves an under deposit corrosion process in waterwall tubing (see Section 3.4). The corrosion damage is generally widespread and produces micro-structural degradation that is not easily detected by conventional inspection techniques. The key approach to hydrogen damage is to prevent the root cause factors that cause damage. These root cause factors are heavy waterside deposits and acidic species in feedwater. Both factors can, and should, be monitored and can be managed to avoid tube damage. Regrettably, these root cause conditions are not being well managed (see Section 3.4) and tube damage is occurring. The consequence is that extensive areas in the furnace need to be inspected for damage and, ultimately, replaced.

For hydrogen damage, the **first** option should be to prevent the damage from occurring. If damage does occur, however, there are now several NDE options for identifying suspect locations. These options do not provide accurate determination of the through-wall extent of the hydrogen damage but do significantly help in reducing the number of locations in which an accurate and more time consuming technique –

such as ultrasonic velocity change[28] – must be applied. Several survey techniques are summarized in Table 7 to indicate their general attributes and capabilities.

Table 7. NDE Survey Techniques for Hydrogen Damage

NDE Technique	Principle of Application	Comments
Ultrasonic Attenuation	Since hydrogen damage involves damage beyond actual wall loss due to corrosion, simple UT thickness measurements are insufficient to reliably detect damage. This UT technique uses the attenuation rate of the signal as a better indicator. The presence of micro-structural damage along with waterside corrosion will cause the signal to attenuate more rapidly.	This technique will be affected by other corrosion mechanisms/existing damage. Does not provide accurate assessment of through-wall extent of damage since attenuation effects due to micro-structural damage are not separable from effects due to ID surface corrosion.
EMAT	Electromagnetic response of material is related to micro-structure, and the EMAT signal is affected by the presence of hydrogen damage.	Wheeled inspection system allows continuous measurement on tubing. Signal may be affected by other micro-structural changes not related to hydrogen damage. Has not been reliable for through-wall extent. Has been used to detect hydrogen damage on tubing with weld overlays.
Eddy Current	Also sensitive to electromagnetic characteristics of material.	Wheeled device that allows inspection with reduced surface preparation. Signal may be affected by other micro-structural changes not related to hydrogen damage.
Active IR	Heat dissipation rate into material is affected by micro-structure and can be detected via IR technique.	Factors affecting signal not limited to hydrogen damage such that scans indicate "anomalous" areas that require further investigation regarding cause.

4.3 The Ugly

A significant area of ongoing development for boiler tube inspections centers on improving detection and characterization of corrosion fatigue cracking (Section 3.1). Corrosion fatigue generally produces cracking away from the more accessible fireside of the tube; it initiates from the waterside surface and usually is located near to an attachment (Figure 2) on the cold side of the tube. It thus presents challenges for cost-

effective detection. EPRI has undertaken projects to detect such cracking using sensors applied to the fireside of the tube. This effort has, however, been a major technical challenge and progress to date has been slow. A current prototype system is being developed using a lamb wave approach. Additional efforts are being considered based upon using radiographic and ID video probes. The video probes would not provide depth sizing but may be useful for screening damage based upon axial extent of cracking. As indicated in Tables 1 and 3 corrosion fatigue damage is at, or near, the top of the list for causes of boiler tube and HRSG tube failures. Development of suitable NDE for this damage mechanism continues to be a high priority for the industry.

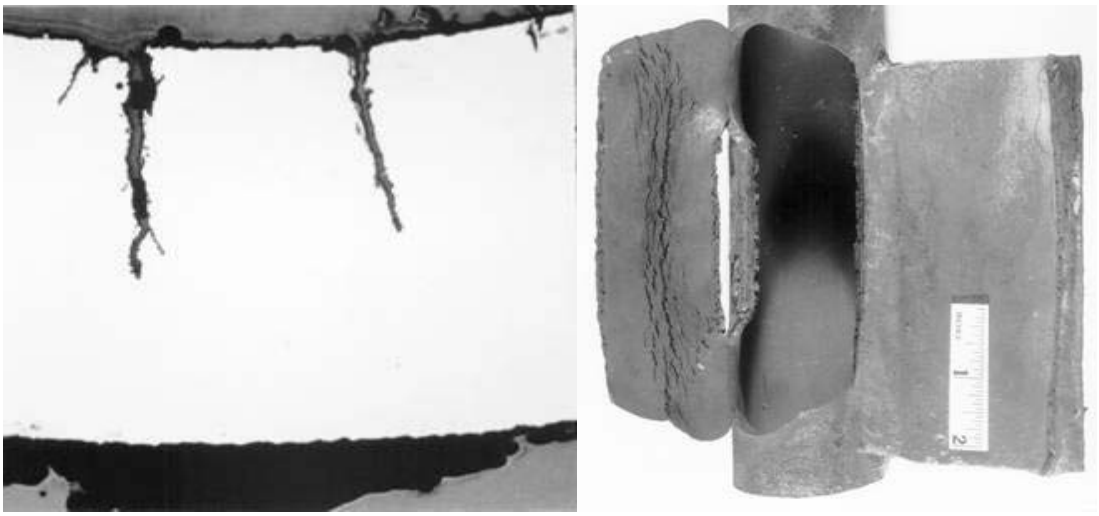

Figure 2. Corrosion-Fatigue Cracking Damage (left shows ID initiated cracking, right shows tube failure)

Another evolving challenge for NDE technology in boiler applications has been created by the increasing use of weld overlays on furnace tubing. Such overlays are made using high chromium (>~25%) material and are required to mitigate high rates of fireside corrosion produced when combustion conditions are modified to reduce NOx emissions. Field applied overlays result in a scalloped surface not conducive to typical inspection techniques such as ultrasonic thickness measurements. Further, the overlays themselves need to be inspected for thickness and for potentially new degradation mechanisms. To date, a number of NDE techniques have been tried on weld overlay surfaces with varying degrees of usefulness and success. For example, EMAT technology was used to search for waterside hydrogen damage. Note that the EMAT system can not accurately measure total thickness for waterwalls with weld overlays. Inductance-based coating thickness gages have also been tried for measuring overlay thickness with varying degrees of success. Finally, active IR scanning can also be used on overlay surfaces but does require suitable references and does not differentiate between damage mechanisms that affect heat dissipation. This area of inspection technology will warrant increased attention in future years and will be included in the EPRI R&D planning process.

Similarly, design differences between fossil steam plants and HRSGs will require development of specialized techniques for tubing in the HRSG. The greater use of finned tubing in HRSGs makes many of the conventional inspection techniques difficult or costly to apply. Here, inspection for damage from inside the tube may be a more cost-effective approach. Development work in this area is being planned and can leverage the large body of work from conventional plant applications. Critical to this NDE development effort will be development of advanced and innovative techniques to allow access to tubing inside diameter. A combination of these advanced approaches will ultimately provide the full range of inspection tools needed to achieve optimum tube life management in HRSGs. A first NDE Guideline for HRSG tubing has been developed[29].

5.0 Concluding Remarks

Application of the BTFRP/CCIP to over 65 organizations since 1997 together with the BTF reduction and cycle chemistry improvement benchmarking of over 100 organizations, provides clear evidence that BTF can be beaten if a coordinated management supported program is adopted. This program moves an organization into the proactive or predictive mode. The cultural change needed is a challenge even for organizations within the program, and appears impossible for those organizations that don't have a senior management supported, coordinated program. There simply appears to be a preference of waiting for failure to occur, and not adopting practices to prevent repeat failures.

In the new HRSG world, there is a clear technical understanding that unless thermal/chemical monitoring is undertaken early in life, that an organization can expect the early ranking of HTF in Table 3 to be consolidated. A technically based HTFRP/CCIP has already been applied to 15 organizations in an attempt to address HTF damage mechanisms early in life.

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SESSION 2: T91 Tube Issues

Chairman: R. Tilley, EPRI

THE UPGRADING OF REHEATER TUBE PANELS IN A COAL FIRED BOILER FROM T22 TO T91 TUBE MATERIAL – HOW EFFECTIVE AN UPGRADE IS THIS PROVING TO BE?

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Abstract

In the mid 1980's, ESB Power Generation commissioned it's Moneypoint Power Station which comprises 3 x 305MWe coal-fired Units. Early monitoring of T22 tubes in the Reheater confirmed micro structural degradation of the material due to uneven flue gas temperature distribution. Sections of these panels were replaced on all three Boilers in the period 1999 to 2000. The tube material for the panels was upgraded to T91. After 30,000 hours operation a number of issues have arisen which has raised concerns about the long term effectiveness of the upgrade. A number of other measures may now have to be considered.

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1. Introduction

1.1. Station Background

Moneypoint is one of Ireland's largest power generating stations. The station is owned and operated by the Electricity Supply Board (ESB). It is located on the Shannon estuary in County Clare on the west coast of the country.

The station has an installed capacity of 915MWe which is approximately 20% of the national output. The station is coal fired with 100% HFO capability. It consists of 3 x 305 MWe Units with Asea Brown Boveri steam turbines and Foster Wheeler drum boilers.

The three Units were commissioned successively in 1985, '86 and '87. The nominal rating for the main steam on these Units is 165 bar at 540 ºC, with reheat steam at 42 bar and also at 540 ºC. The station operates as a high merit base load plant and the Units are now approaching 140,000 actual run hours.

1.2. Objectives of Paper

The purpose of this paper is to outline the degradation that occurred to sections of Reheater tubing in the Boilers at Moneypoint and to outline the corrective measures that were taken to eliminate this and to recognise the limitations that may be arising in these corrective measures in the last number of years.

The paper will describe;

- The degradation that occurred in the original T22 tube material.
- The modifications that were carried out in 1999/2000 on all three Boilers which resulted in sections of the original T22 tube panels being replaced with T91 tube material.
- The damage that has occurred on the replacement T91 material and the results of the monitoring that has recently been carried out.
- The implications for the long term integrity of the Reheater tube panels and an outline of what future actions maybe required.

1.3. Description of Reheater

The Reheater of the Moneypoint Boilers is located in the rear pass of the Boiler as shown in Figure No. 1. The Reheater is designed in three different sections comprising of a lower horizontal tube section, an upper vertical tube section and a final horizontal tube outlet section. The steam flow in the Reheater is vertically upwards and counter to the flue gas flow. The inlet header is located in the flue gas path in the lower section of the rear pass. The outlet header is located in a dead space external to the Boiler.

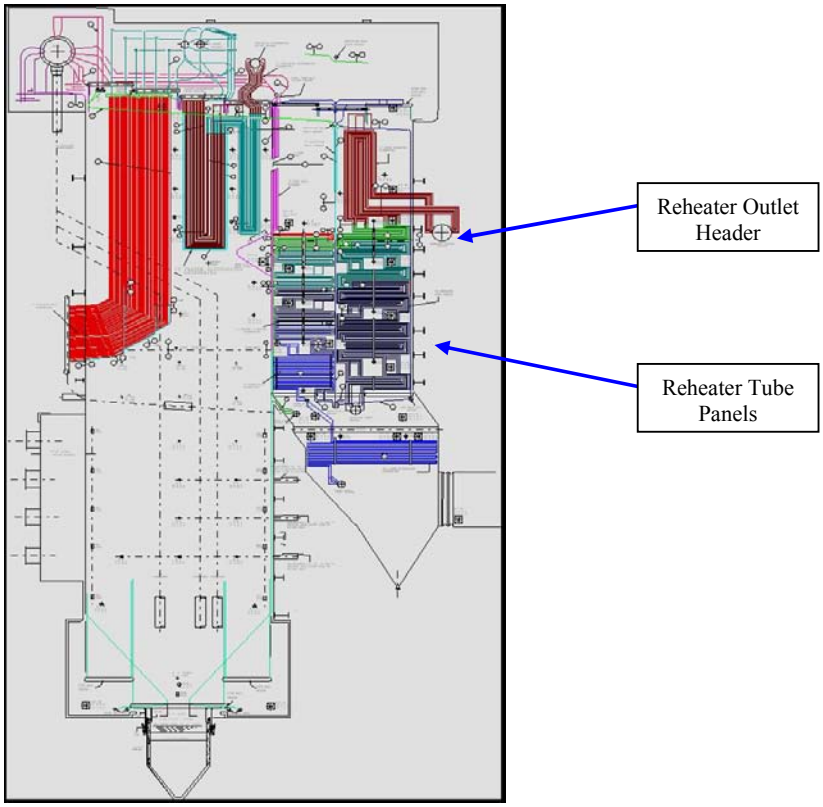

Figure No. 1: Cross Section of Boiler

The upper section of the Reheater is the area of particular interest for this paper and is detailed in Figure No. 2. Details of the original 'as-built' tubing are given in Table No. 1.

Location	Material	Dimensions	Details
Lower Horizontal tube panels above sootblower 81/82	a) SA-213T2 b) SA-213T11	a) 51mm OD x 4.2mm wall b)51mm OD x 4.6mm wall	94 panels of 7 tubes
Vertical 'dog-leg' tube panels	SA-213T22	51mm OD x 4.6mm wall	47 panels of 14 tubes
Horizontal outlet tube panels	SA-213T22	44.5mm OD x 4.6mm wall	47 panels of 14 tubes

Table No. 1: Reheater Tube Details

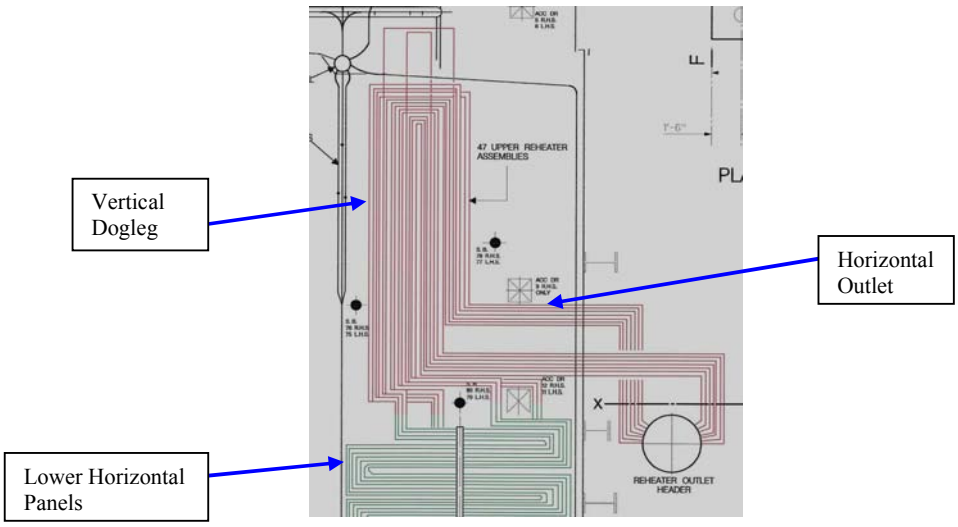

Figure No. 2: Upper Section of Reheater

2. Degradation of Original T22 Tube Panels

In June 1988 tube samples were removed from the front of the vertical dogleg of the Reheater on Boiler No. 2. The tube material at this location is T22. At that stage the Unit had only been in operation for a total of 17,000 hours. The purpose of the sampling was; to monitor the growth of the internal oxide; to derive from this their probable temperature history; and to establish the need for any future chemical cleaning. The results showed however that the microstructures and hardness values were indicating that the tubes were being overheated. Further sampling was then carried out on Boiler No. 3, which at that stage had accumulated 9,000 hours, and similar results were found.

A detailed investigation was carried out at the time which established that the Reheater outlet steam temperature as measured before the Outlet header exhibited a distinctive 'M' shaped profile as shown in Figure No. 3. This was attributed to stratification of the flue gas in the upper region of the Boiler furnace. The peaks of the profile were on tube panels 4 to 11 and on panels 37 to 45, with the highest peak being on the right hand side. At the peaks of the 'M' some of the tubes were experiencing steam temperatures in the range 570 – 600˚C at the Outlet Header. This obviously indicated that tube metal temperatures in excess of this were being experienced in the flue gas stream.

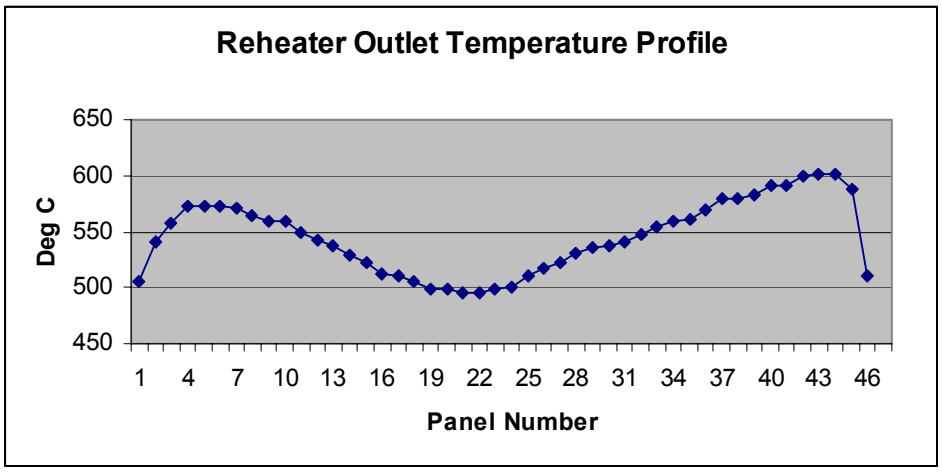

Figure No. 3: Temperature Profile

Remnant life calculations were also carried out to establish the creep life of this outlet section of the Reheater. This indicated that the creep life was dependent on the corrosion rate used in the calculations. It was assumed at the time that the corrosion rate could be between 1.0mm/100,000 hours and 2.5mm/100,000 hours. This resulted in a creep life of between 92,500 hours and 144,000 hours, respectively. Based on the projected base load running for these Units this implied that the tubes should remain serviceable until the mid to late 1990s. On-going inspection and monitoring was carried out on all three Boilers throughout this period.

Results from the 1997 inspection of the front tubes of the vertical doglegs are given in Table No. 2. The 1988 figures are shown for comparison. Readings are from Boiler No. 2 and are similar for all three Boilers.

At that time inspection was also carried out on the horizontal outlet section of the Reheater. The results were similar to the vertical dog-leg in that the wall thickness had reduced to as low as 3.6mm and the internal oxide readings had increased to 900µm. However the low readings were not measured on the top leading tube of the tube panel but on the 7th or 8th tube down from the top. This was the situation on all three Boilers.

	1988	1997
Hardness; HV	130-140	116-120
Wall Thickness; mm	4.5-4.8	3.3-3.9
Internal oxide; µm	60-200	500-900

Table No. 2: Inspection Results from Boiler No. 2

Tube failures occurred in the upper Reheater tube panels in 1998 on both Boiler No. 2 and 3 after approximately 90,000 hours operation. The failure mechanism was high temperature creep. The tube failure on Boiler No. 2 was on tube 8, panel 44 on the horizontal outlet section. The failure on Boiler No. 3 was on the leading tube of the vertical dog-leg on panel 42. See Figure No. 4.

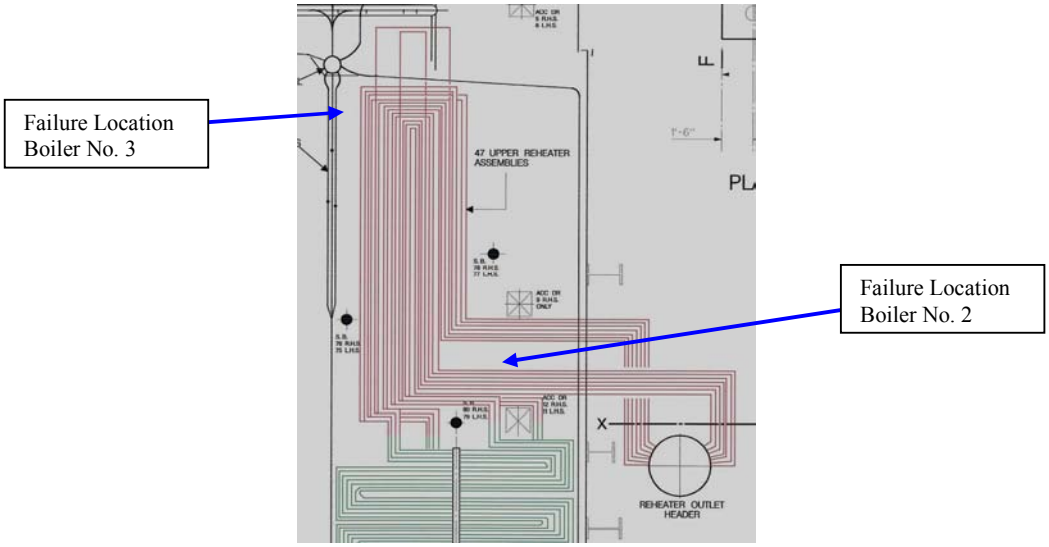

Figure No. 4: Failure Locations

3. Upgrading Project

Given the extent of degradation being monitored in 1997 a decision was made to start planning the replacement of sections of the upper Reheater. Based on the overhaul schedule for these Units the replacement work was to be carried out on all three Boilers in the period 1999 to 2000.

Different options were considered ranging from partial replacement to complete redesign and replacement of the Reheater. However as a limited overhaul period was available it was decided to select the more critical locations for replacement. Analysis of the inspection results and temperature data identified 16 of the 47 upper panel sections for replacement namely, panels 4 to 10 inclusive, and panels 37 to 45 inclusive. Another critical decision centred on the material to be used for the

replacement tube panels. It was considered that alternatives to T22 material should be sought and that the alternatives should be capable of operating to the peak of the temperatures exhibited by the 'M' profile.

The scope of work was also extended to include the replacement of the Reheater Outlet Header due to failures that had occurred in the seam weld of the original P22 header. The material of the replacement header was also to be upgraded to take account of the temperatures of the 'M' profile.

A number of boiler companies were asked to submit tenders for this work in accordance with EU procurement directives and the contract was subsequently awarded for the supply and installation of the replacement tube panel sections and outlet header in July, 1998. The extent of work is as illustrated in Figure No. 5. Work was carried out on Boiler No.'s 1 and 3 in 1999 and on Boiler No. 2 in 2000.

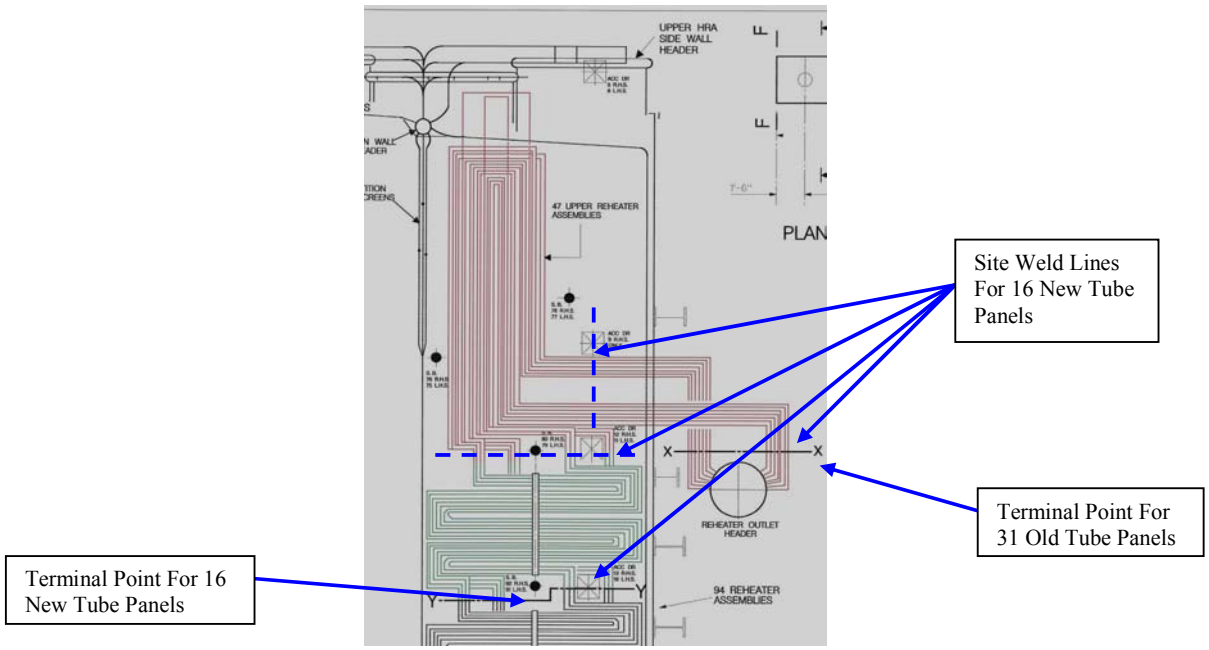

Figure No. 5: Replacement Details

The design, manufacture and installation was carried out in accordance with BS1113-1998. The main design parameters for the replacement pressure parts were as follows;

- Design Pressure; 54.5bar
- Design Temperature; 645˚C for the Tube Panels
  620˚C for the Header
- Material Specification; BS3059PT2 S291 for the Tube Panels (T91)
  BS3604PT1 HFS91 for the Header (P91)
- Dimensions; As per the original arrangement as only a partial replacement was being undertaken

The programme of work, from start of dismantling to completion of erection, was completed within 8 weeks on each Boiler.

4. Damage Observed after 30,000 hours Operation

4.1. Header Antler failure:

In August 2001 a steam leak was detected on Boiler No. 1 on a stub-antler to header weld on the Reheater Outlet Header after 16,000 hours of operation.

The leak was located in the antler side toe of the antler to header weld, see Figure No. 6. It was evident from the initial visual examination that the antler had been strained and was out of line. A number of other antlers were seen to be similarly strained. The failed antler was removed and extensive NDT and in-situ metallography was carried out on adjacent antlers. No cracks were found on other antlers at that time.

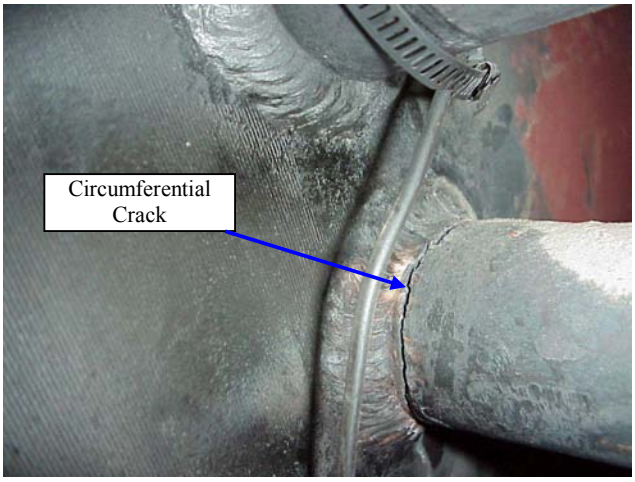

Figure No. 6: Failed Antler

Examination of the failure indicated that the failure mechanism was creep, see Figure No. 7. The cracking and creep damage had accumulated in the weaker intercritical region of the HAZ i.e. more commonly known as a Type IV failure. This region of the HAZ in welded T91/P91 material appears to be a region that is particularly prone to creep damage accumulation. The creep damage appeared to be uniformly distributed through the wall of the tube.

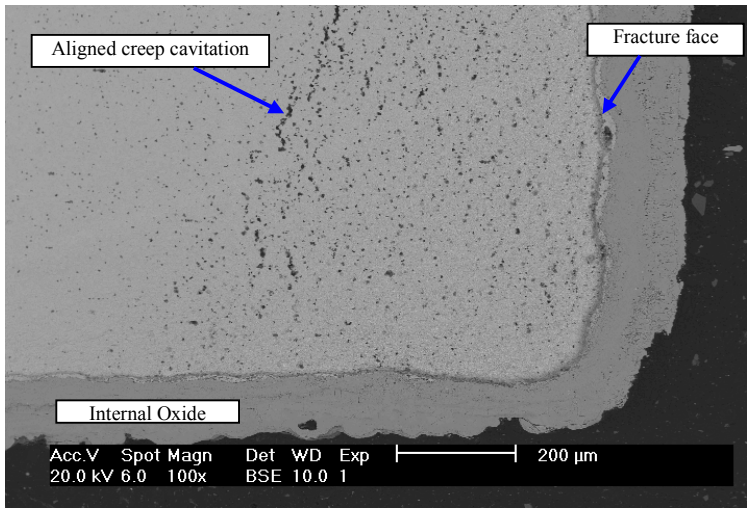

Figure No. 7: Section through the fracture at the internal surface

The composition of the material in the failure was determined using a laboratory-based spectrometer, see Table No. 3 for details. The quantity of nitrogen was determined using a Leco TC - 136.

C	Si	Mn	P	S	Cr	Ni	Mo	Cu	Al	Nb
0.111	0.353	0.409	0.01	0.003	8.24	0.14	0.978	0.165	0.015	0.066

Ti	As	V	W	Co	Sn	B	N	Ca	Ce	Sb
0.004	0.006	0.225	0.055	0.016	0.011	0.006	0.0615	0.0011	<0.002	<0.002

Table No. 3: Material Composition of Failed Antler

This corresponds to T91. All elements are within the specified limits and did not contribute to the failure.

Several hardness surveys were carried out on sections of the failed antler. Typical results are shown in Figure No. 8. The results are in Vickers Pyramid Number. Hardness figures of 180HV were recorded but this may have been affected by the level of creep damage in the region. Other hardness traverses across these welds showed a hardness drop from 220HV in the parent to 190HV in the intercritical region of the HAZ. This hardness drop is considered excessive and has been identified as a contributing factor in premature Type IV creep failures (ref. EPRI TR1004516 *'Performance Review of P/T91 Steels'*). PWHT applied during the welding process was carried out at 765˚C with a tolerance of ±15˚C.

The failure was attributed to excessive system stresses placed on the antler by a cladding rail that was rigidly attached onto the failed antler and which resulted in the strain on the antler. These stresses lead to an accumulation of creep damage in the antler side HAZ and to premature failure. A new antler was fitted and the Unit

returned to service. All strained antlers were subsequently replaced. Examination of these antlers found significant creep damage had accumulated in the antler side HAZ. The cladding rail attachment was also modified.

The T91/P91 weldments would appear to be less tolerant of additional system stresses when compared to the T22/P22 alloys as this type of strain had been detected on the original T22 antlers but no failures had occurred.

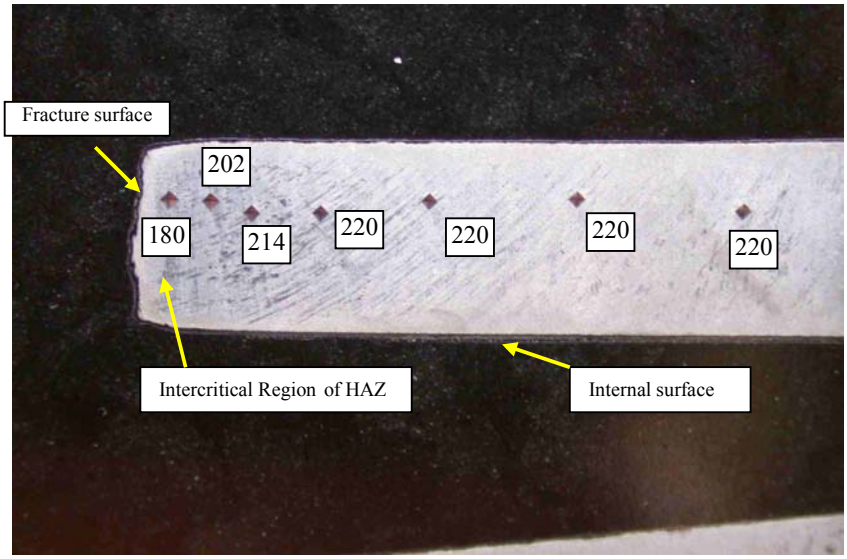

Figure No. 8: Hardness survey on longitudinal section

Detailed inspection was carried out on the antlers on Boiler No's 2 and 3 in 2003. No significant strain was measured on the antlers and no creep damage was detected from the in-situ replication of the antler to header welds. It was also noted that the cladding rail attachment detail was different on Boiler No's 2 and 3.

No other failures of this type have since occurred.

4.2. Gas path tube degradation

Wall thickness and internal oxide measurements were carried out on a selection of T91 tubes across the Reheater tube panels as part of the 2001 Boiler No. 3 inspection program. The measurements were taken in the horizontal outlet section in the gas path and also in the deadspace before the Outlet Header. Similar inspections were carried out in Boiler No. 1 (2002) and Boiler No. 2 (2003). These results showed some internal oxide thicknesses in the region of 250µm after approximately 20,000 hours of operation. See Table No. 4 for a summary of typical results from Boiler No. 2 which were taken in 2003 after 24,000 hours of operation. Several of the tubes showing the highest readings were hardness tested and metallurgically replicated to determine if the material was showing evidence of thermal degradation. Where possible the same tube was inspected in the dead space.

The results listed in Table No. 4 are typical of those measured in the other Boilers after 20,000 to 30,000 hours and indicate that significant thermal degradation has occurred in these tubes. The average hardness for such a material in the un-serviced condition would be approximately 225 HV. The reduction of hardness indicates a significant reduction in the mechanical properties of the material.

Location	HV	Internal Oxide Thickness
Tube 7, Panel 40 before reducer	180	240µm
Tube 7, Panel 40 after reducer	175	220µm
Tube 8, Row 40 before reducer	148	290µm
Tube 8, Row 40 after reducer	161	240µm

Table No. 4: Typical Inspection Results for Boiler No. 2

The results of the metallurgical replication also showed that there was a significant change in the structure between a 'heated' tube in the gas path and an 'unheated' tube in the dead space, see Figure No.'s 9 and 10. The degree of carbide precipitation is an indication of the amount of thermal degradation suffered by the material. Carbide precipitation can be clearly seen in Figure No. 10. The rate of precipitation is linked to the temperatures experienced by the material. It is recognised that careful assessment is required of in-situ metallurigical replication due to surface affects such as decarburised surface. It is proposed to take tube samples during the next scheduled overhaul.

Temperature estimations and remnant life calculations were carried out using ISO material property data. This indicated a maximum metal temperature in the gas path of 611ºC with an internal oxide figure of 290µm. Using this temperature figure along with typical internal oxide and wall thickness measurements from 2003 of 290µm and 4.29mm, respectively, in the remnant life calculations indicated a remaining life of the order of $4X10^5$ hours. However it should be noted that this based on typical data. Lower wall thicknesses have been measured and when a figure of 4.0mm is used in the calculations the remaining life reduces to 190,000 hours. The calculations assume that the corrosion rate remains uniform through the life of the component. This may not be the case for this grade of material.

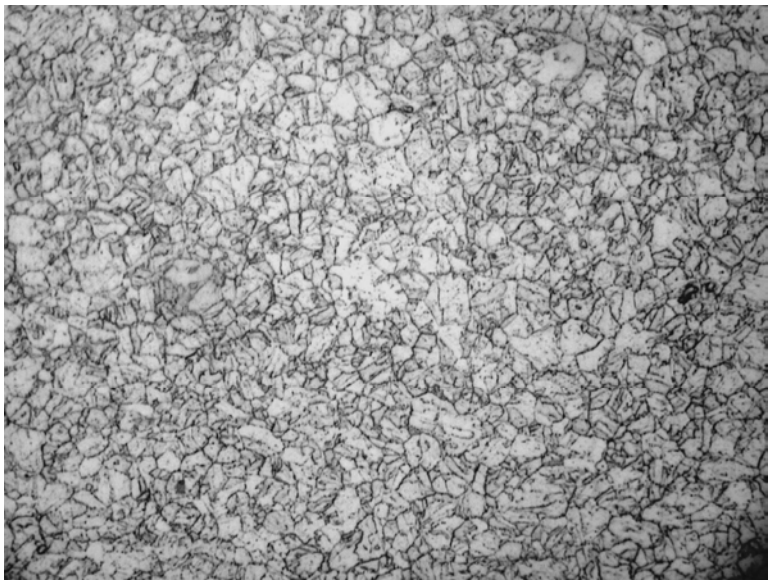

Figure No. 9: Microstructure of tube in the dead space after 24,000 hours, X500, Marbles etch

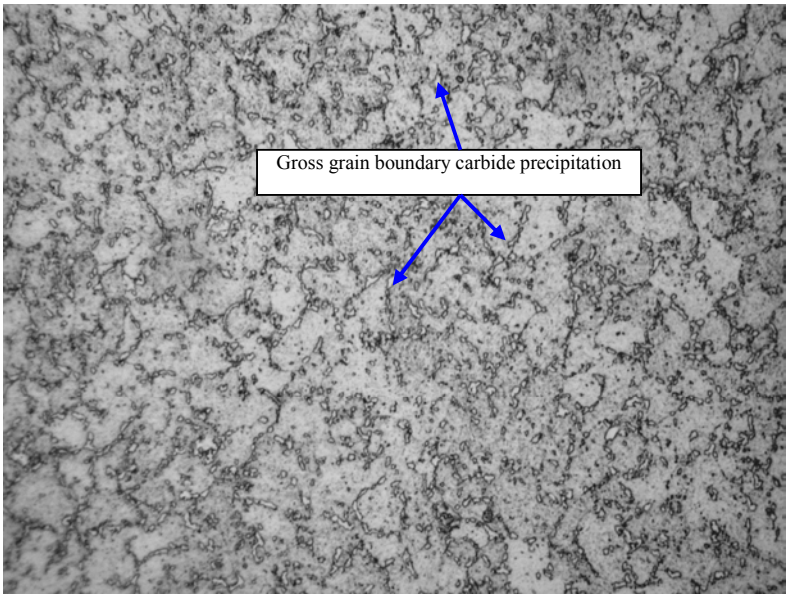

Figure No. 10: Microstructure of tube in the gas path after 24,000 hours, X500, Marbles etch

5. Future Actions

Further ongoing metallurgical assessment and NDT inspection will be required on the T91 tube panels. This will continue on Boiler No. 1 during the scheduled overhaul planned for September 2004 and will include the taking of tube samples for laboratory assessment. Results will be included in the Conference presentation. Reinspection of the antler to header welds will also be required within five years.

Additional work will be carried out on the remnant life calculations as further inspection results become available. It is intended to develop a remnant life map of the upper T91 tube panels on all three Boilers based on measured data. Early prediction of any potential 'end of life' of the T91 material is of vital importance for the availability of these Units.

Extensive flue gas cleaning equipment is to be installed all three Units during the next three years. Investigations are currently being carried out to establish if modifications can be carried out to the coal fired burners which may result in a lowering of the 'M' temperature profile. It may not be possible to eliminate the profile entirely but some reduction in the peaks may be possible.

Given the level of internal oxide on both the T91 panels and the remaining T22 panels, an assessment is currently being carried out on the logistics of carrying out an acid wash of the complete Reheater on all three Boilers. The earliest date for an acid wash would be 2006 given the proposed outage schedule for these Units.

Further replacement of some of the remaining original T22 tube panels is envisaged over the next three years. It is quite probable that on this occasion the tube material will not be upgraded to T91 and that T22 tube panels will be installed. A final decision has not been made on this yet.

Evaluation of Long-term Overheat Creep Failures of SA213 T91 Superheater Tubes in Appalachian Power's Glen Lyn Plant

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In August of 2003 a long-term overheat creep (LTO-C) failure of SA213 T91 tubing occurred in the secondary superheater at Appalachian's Glen Lyn Unit 6. The tubing had been in service for approximately 61,000 hrs (8 years). The tubing failed in the classic thick-lipped fish mouth pattern with minimal swelling around the rupture. The secondary superheater has a design outlet pressure and temperature of 2075 psig (14.41 MPa) and 1050°F (565.6 ^{o}C) respectively. Metallurgical analysis determined that the failure mechanism was LTO-C.

Additional analysis indicated that tube metal temperatures well above the tube metal design limits. This was exacerbated by the buildup of thick, laminated steamside scale that was responsible for the short service life. It was recommended that steamside oxide scale thickness surveys be performed to determine the effective temperature and remaining life distributions of the secondary superheater tubing.

Ultrasonic measurements of the steamside oxide thickness were performed to estimate the effective steam and tube metal temperatures and remaining life. Steamside oxide scale thickness measurements of the penthouse tubing confirmed that the secondary superheater had operated with an average outlet steam temperature near the 1050°F (565.6^{o}C) design value but that approximately 20% of the tube circuits (including the circuit with LTO-C failure) had outlet steam temperatures above 1100°F (593.3^{o}C).

Measurements made on tubes within the furnace indicated that buildup of relatively thick steamside oxide scale was leading to tube metal temperatures above 1200°F (648.9^{o}C) in approximately 15% of the tube circuits. To prevent additional LTO-C failures a combination of selected tube replacements and steam flow redistribution (TUBEMOD®) to lower peak temperatures and prevent future failures was engineered and implemented.

The evaluations of this secondary superheater have demonstrated the usefulness of steamside scale and special creep cavity severity based life assessments. It has also raised

some concerns regarding the oxidation temperature limits for T91 tubing for use in superheaters or reheaters. In particular, practical oxidation limits must be established for this material, making further study imperative.

INTRODUCTION

Glen Lyn Unit 6 is a 2400 psig (16.65 MPa) pulverized coal fired, Babcock & Wilcox designed, sub-critical boiler with natural circulation that went into service in 1957. The unit is a 240 MW radiant boiler with a single reheat section. The design conditions for main steam are 2070 PSIG (14.37 MPa) with superheat and reheat steam temperatures of 1050°F (565.6^{o}C). Prior to the LTO-C failure the unit operated at a superheater outlet pressure of 2,000 psi (13.89 MPa) and a bulk outlet temperature of 1050°F (565.6^{o}C). The unit operates in a load following mode with six to eight load changes per day. Each day the unit experiences short term temperature excursions associated with load adjustments. The magnitude, speed, and frequency of the load swings have an impact on the main steam temperature changes. Normally the main steam temperature during these changes is maintained within approximately ±10°F (5.6^{o}C). Under more severe conditions main steam temperatures as high as 1070°F (576.7^{o}C have been recorded.

Historical review revealed that the secondary superheater (SSH) section was replaced twice since 1957. The original SSH TP321 stainless steel tubes failed after 12 years of service. The superheater outlet bank installed in 1969 was upgraded to a 304 H grade stainless steel material. This SSH provided 26 years of service. There were significant problems with dissimilar metal welds (DMW) over its life. An engineering study was commissioned in 1993 to review the history of the unit and recommend an appropriate course of action leading to the replacement of the complete secondary superheater. The final analysis favored T91 over 304H for the outlet bank. Not only were the material costs lower but it also eliminated the long-term problems with the DMWs. As part of the 1995 superheater refurbishment the SSH outlet header was also replaced. The material selected for the header was P91. This step eliminated all the material variations of the hot end all the way to the main steam piping.

From 1995 to the first T91 tube failure in 2003 there were no significant events noted. In this 8-year period the unit operated for 61,245 hours with 52 shut down and start up cycles. Originally Glen Lyn was designed to be base loaded, but like many other small sub-critical units, it must cycle on a frequent basis. Large swings from full load (~240MW) to minimum load (~100MW) are experienced on a daily basis. The introduction of Automated Generation Control (AGC) creates nearly continuous small adjustments in load. These small, rapid changes can create substantial swings in steam temperatures, especially at lower loads.

The superheater section is designed with sixty six elements across the unit with four parallel circuits per element (Figure 1). The original superheater was fabricated with 2-inch (50.8 mm) outside diameter x 0.260-inch (6.6 mm) minimum wall thickness SA213 Type 321 stainless steel tubing. This Type 321 tubing was replaced in 1969 due in part to LTO-C failures that occurred in part due to an incorrect original heat treatment of this tubing.

The SH tubing was replaced with 2-inch (50.8 mm) outside diameter x 0.284-inch (7.21 mm) minimum wall thickness SA213 Type 304H tubing. The 304H tubing was used for approximately 26 years (until 1995). In 1995, the superheater tubing and outlet headers were replaced with 2-inch (50.8 mm) outside diameter x 0.285-inch (7.24 mm) minimum wall thickness SA213 T91 material. The SSH outlet header was also replaced in 1995 using P91 material.

In August of last year, a failure occurred in the superheater approximately two feet (0.61 m) below the roof on the outlet tube leg (Figure 2). The failure occurred in the 41st of 66 elements (counted from the right side of the unit while looking toward the rear of the unit) in the second of the four tube rows (i.e., the 6th tube in from the front of the SSH) of the final SSH outlet leg leading to the outlet header (Figure 3). The failure occurred just beneath the top alignment bar. Visual examination of the superheater revealed that the tube circuits, including the failed circuit were in excellent alignment with no evidence of any bowing or distortion. The T91 failure occurred after approximately 8 years (61,000 hrs) of service.

This unit was found to have orifice plates installed in the inlet tubing to the secondary superheater. The orifice plates were found to be installed in three of the four tube circuits of the secondary superheater (Rows 6, 7 and 8 had orifice plates).

There are two items which made this particular event at Glen Lyn unique. First, the LTO-C failure occurred about 20 years ahead of schedule. Secondly, the tubing material, SA213 T91, is an industry favorite and wasn't expected to fail prematurely due to LTO-C. The significance of the Glen Lyn tube failure lies in the fact that a potential weakness of T91 for use in superheaters is brought to light. Allowable stresses are well established, however; the excellent creep properties appear to be limited by rapid buildup of a multilayered steamside oxide scale that significantly increases the tube metal temperature above the steam temperature.

The challenge is now to gain understanding of the physical and mechanical properties and damage mechanism inherent to T91 superheater tubing which drove the expected life from 25 to a scant 8 years. For example, Figure 4 presents the estimated time to failure for T91 tubing operating at stress levels between 5.25 ksi (36.2 MPa) to 5.90 ksi (40.7 MPa) and a range of temperatures. These are the estimated beginning and final mean diameter formula hoop stress values for the failed tube. These predictions are in excellent agreement with a few experimental tests performed by the National Research Institute for Metals in Japan (NRIM)[1] on T91 material within this range of stress and at a test temperature of 1292°F (700°C). Based on these estimations it is concluded that for a LTO-C failure to occur in approximately 61,000 hours a constant midwall tube metal temperature in the range of 1230°F (665.6^{o}C) to 1240°F (671.1^{o}C) would need to have occurred. This is more than 100°F (55.6^{o}C) hotter than the hottest measured SSH outlet penthouse tube. To attain temperatures in this range would require high heat flux values in combination with buildup of a thick insulating steamside oxide scale.

For comparison, a bounding estimation of the anticipated time to failure for the Type 304H dissimilar metal welds was performed using an empirical model developed by KEMA[2] (Figure 5). These estimations indicate that DMW failures would be expected within the 26 years of service for a very moderate axial stress (i.e., approximately 3.6 ksi (25 MPa)) and a midwall temperatures in the range of approximately 1160°F to 1180°F (571°C to 638°C). This is well within the range of the steady state temperature anticipated for the hottest tube circuits.

A few tubes failing ahead of time may not seem critical, but there are thousands of miles of T91 tubing in superheater and reheater service in fossil-fired plants around the world, all very similar to Glen Lyn Unit 6. Managing boiler availability is important to every utility. By their very nature, repairs done within the boiler take substantial time and effort. The financial impact of lost generation over several days can range from significant to severe given the occasional volatility of power prices.

Figure 1 – Layout of the superheater.

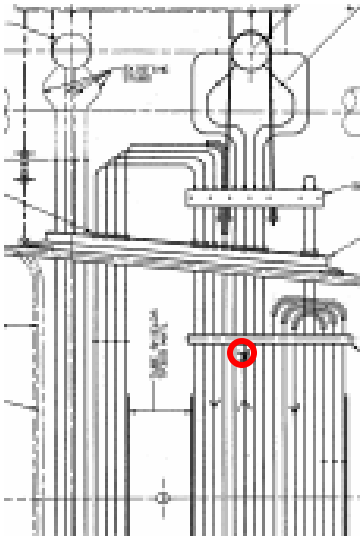

Figure 2 – Location of the T91 LTO-C failure (Element 41 of 66, Row 2 of 4 of the final outlet leg, approximately 2 feet (0.61 m) below the roof).

Figure 3– Thicked edged, axial rupture of T91 secondary superheater tube

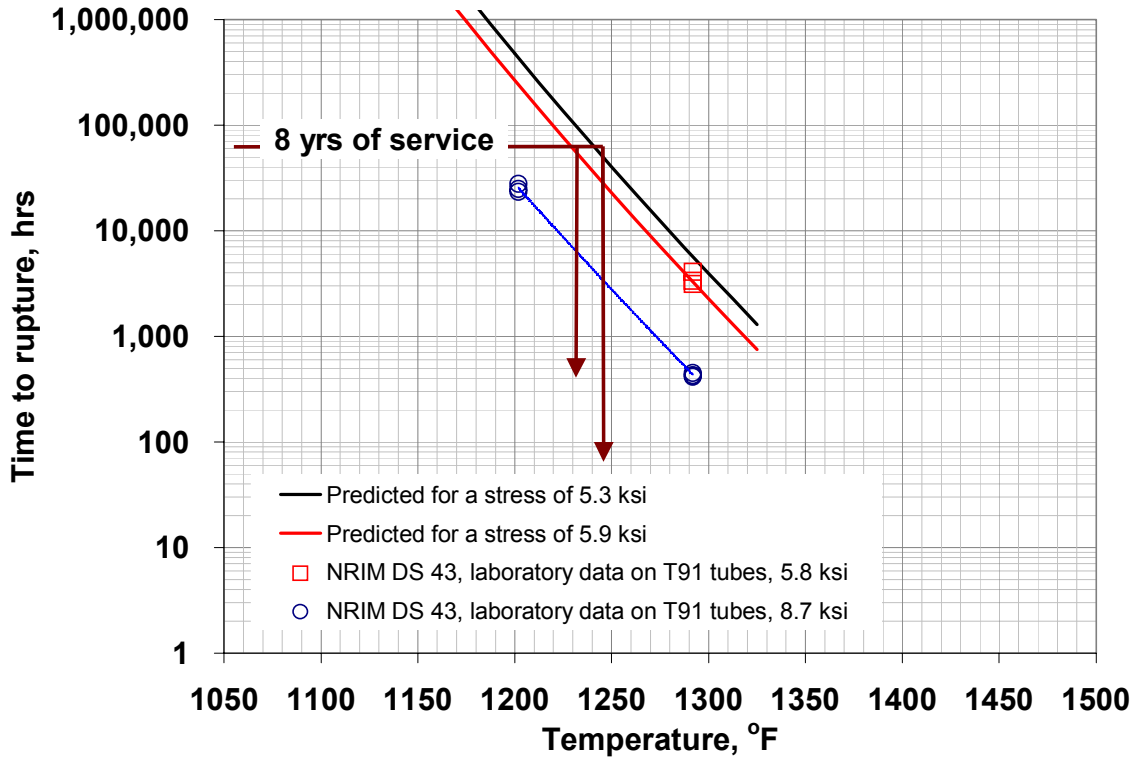

Figure 4 – Estimations of the time to rupture for T91 material exposed to stress levels in the range of 5.3 ksi (36.5 MPa) to 5.9 ksi (40.7 MPa) and a range of temperatures. The NRIM laboratory data points[1] were for three different heats of T91 tested at a temperature of 1292°F (700°C). For a LTO-C failure to occur in approximately 8years (61,000 hrs) at these stress levels would require a continuous temperature in the range of approximately 1230°F (665.6°C) to 1240°F (671.1°C). Greater than 300,000 hrs of life would be anticipated for tube temperatures below 1200°F (648.9°C).

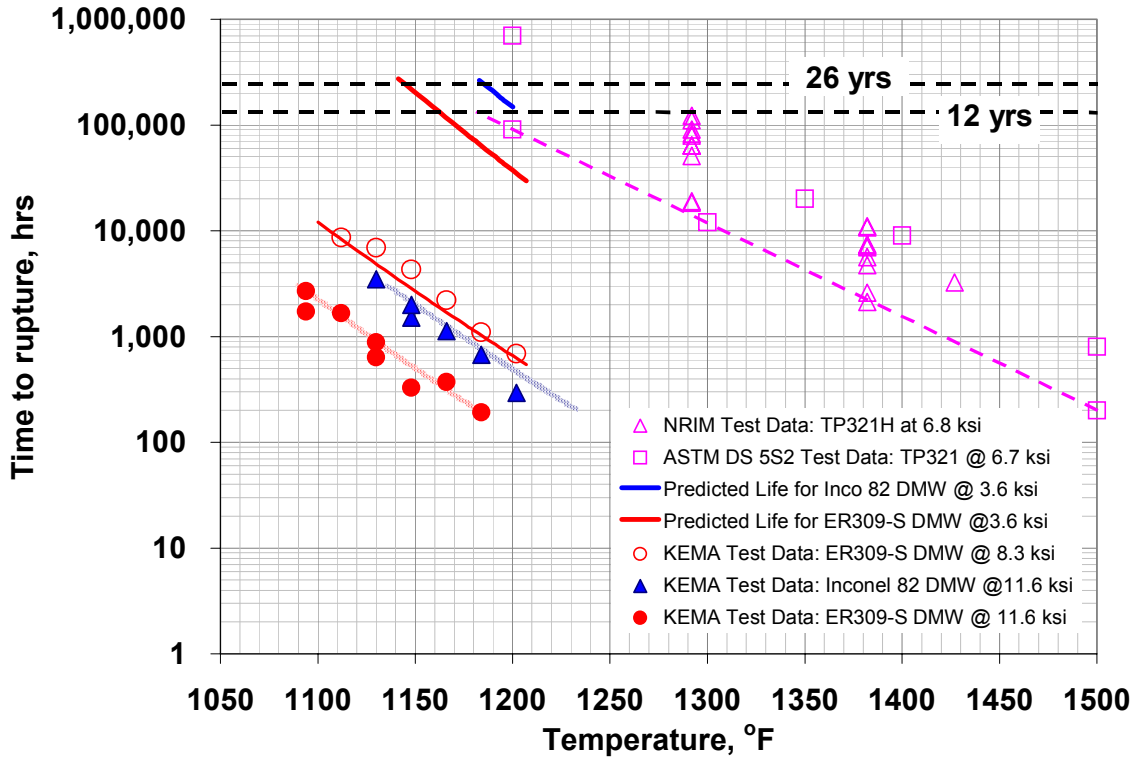

Figure 5 – Estimations of the time to rupture for the TP321 and TP321H tubing and ER309-S and Inconel 82 type DMWs. The poorly heat treated TP321 tubing was removed from service due to LTO-C failures that occurred during its 12 years (~120,000 hrs) of service The TP304H tubing was removed from service following 26 years (~210,000 hrs) of service after it experienced DMW failures. The LTO-C failure history of the original TP321 tubing and DMW failure history of the TP304H tubing suggest that tube temperatures approaching 1180°F (638°C) may have been active in the hottest tubes in the 1st and 2nd SSH designs.

USE OF SA213 T91TUBING IN FOSSIL-FUEL-FIRED BOILERS

Modified 9 chrome boiler tubing, by utility standards, is a new material. T/P91 was developed in the mid 1980s, but its wide spread acceptance and use did not start until the early to mid 1990's. The high cost of stainless steel goods forced utilities and boiler OEMs to consider alternate materials. Excellent high temperature strength, low coefficient of expansion, and favorable cost made T/P91 the material of choice then and now.

T91 material in fossil boilers has been increasingly used over the past decade as an alternative to stainless steel and alloy steels, such as T22. The material has had extensive use overseas in Japan and Europe and has been used in high temperature applications in piping as well. In the US, T91 boiler tubing has been applied infrequently in conventional fossil-fuel-fired plants due to the lack of new construction occurring, but has been given increasingly more consideration over the years with retrofit applications.

EPRI Report 1004516 "Performance Review of T/P91 Steels" lists approximately 40 T91 tube applications in fossil-fuel-fired plants since 1985. Several early service life failures in these T91 applications have been reported. Improper heat treatment, post weld heat treatment and flame straightening during erection have been associated with the reported failures.

T91 has spurred the introduction of similar alloys, such as T92 for use on more advanced power plants. On the other hand, T91 has become the preferred tubing for high pressure superheater and reheater modules in heat recovery steam generators.

METALLURGICAL EVALUATION OF THE TUBE FAILURE

Metallurgical evaluations of the failed tube (Figure 3) and an adjacent tube (i.e., Row 5, Platen 40) removed from the same elevation were performed to determine the damage mechanisms, and to provide information to be used to fine tune the remaining life estimations of other circuits and elevations within the SSH.

The failed tube exhibited a thick-lipped, fishmouth, LTO-C rupture with severe intergranular creep cavitation across the entire wall thickness (Figure 6). The tube exhibited the thickest steamside oxide scale (0.029" or 0.737 mm), highest density of creep cavities (1260 per mm^2), thinnest wall thickness (0.29" or 7.37 mm) and the lowest midwall hardness (83.6 HRB) at the location of the rupture (Figure 7).

The microstructure of the tube consisted of tempered martensite with a combination of fine, disperse carbides and coarsened grain boundary carbides. In the hotter portions of the tube the coarse grain boundary were more prevalent and the fine, disperse carbides were less apparent. No evidence of intercritical overheating or improper heat treatment of the tube was observed.

Chemical analysis (Table 1) confirmed that the chemistry of the tubing was within the required limits for SA213 T91 tubing.

Table 1 – X-ray fluorescence chemical analysis of selected sections of T91 tubing

Element	Pendant 40 of 66 Outlet Leg Row 1 of 4	Pendant 41 of 66 Outlet Leg Row 2 of 4 (LTO-C Failure)	SA213 T91 Requirement
C	Not analyzed	Not analyzed	0.08-0.12
Mn	0.45	0.32	0.30-0.60
P	0.008	0.012	0.020max
S	0.001	0.010	0.010max
Si	0.38	0.59	0.20-0.50
Cr	8.34	8.09	8.0-9.5
Mo	0.91	0.93	0.85-1.05
V	0.22	0.23	0.18-0.25
Cb	0.08	0.07	0.06-0.1

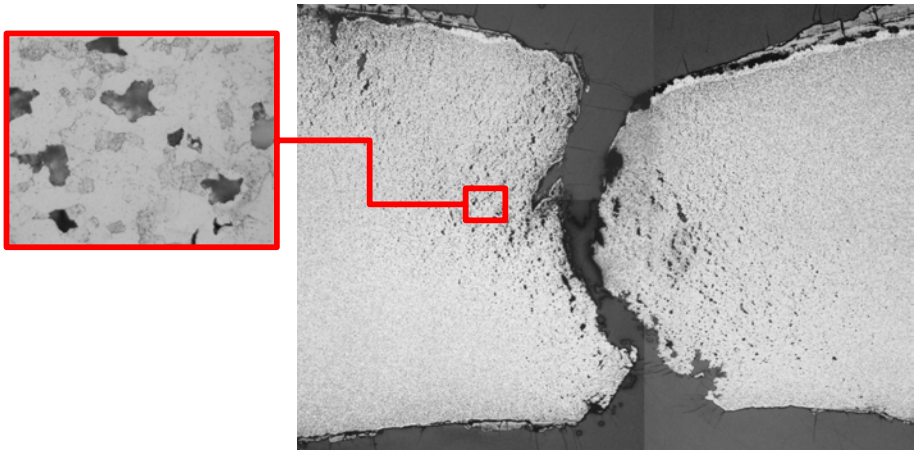

Figure 6 – Cross-section through center of rupture

Location (Degrees from leading edge)	-180	-120	-60	0	60	120	180
Wall Thickness (inch)	0.310	0.300	0.320	0.310	0.290	0.315	0.310
Oxide Thickness (inch)	0.0260	0.0200	0.0225	0.0265	0.0290	0.0260	0.0260
Midwall Hardness (HRB)	89.5	94.3	94.0	91.2	83.6	83.6	89.5
Creep Cavity Density (mm^{-2})	1155	758	505	469	1264	1083	1155

Location (Degrees from leading edge)	0 - 180	60-(120)	(60)-120
Outside Diameter (inch)	2.03	2.02	2.025
Inside Diameter (inch)	1.410	1.430	1.390

Figure 7 – Distribution of metallurgical attributes around the periphery of the tube. The tube rupture occurred between the zero and 60-degree locations.

The steamside oxide scale was unusual with respect to its thickness (Figure 8), multilayered scale (Figures 8 and 9), delamination (Figures 8, 9 and 10), blistering (Figures 9 and 10) and exfoliation (Figure 10). The causes, consequences and mechanisms of these oxide scale characteristics are being studied in ongoing[3] and newly initiated EPRI research projects. The rapid growth and breakdown (i.e., thick, multilayered oxide with delaminations and blistering) of the steamside were not anticipated and may indicate that the common maximum service temperature limit of 1200°F (618.9°C) for this and similar materials may be far too optimistic for superheater tube applications. The layering in the inner region of the scale is not unusual for T91 or other common Cr-Mo tube alloys such as T9 and T22. It has been duplicated in many laboratory studies[4, 5] and has sometimes been associated with rapid, linear growth rates of oxide. Wustite (FeO) and ferrite formation may be involved with the growth of the multilayered regions[5] in the scale.

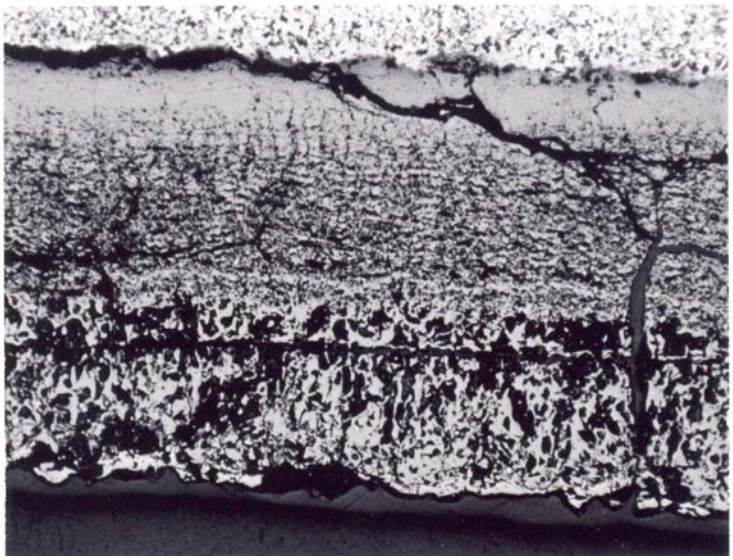

Figure 8 – 0.029-inch (0.737 mm) thick steamside oxide scale delamination at the metal interface and in the outermost magnetite (Fe_3O_4) layer. Also note the extensive layering in the inner half of the scale.

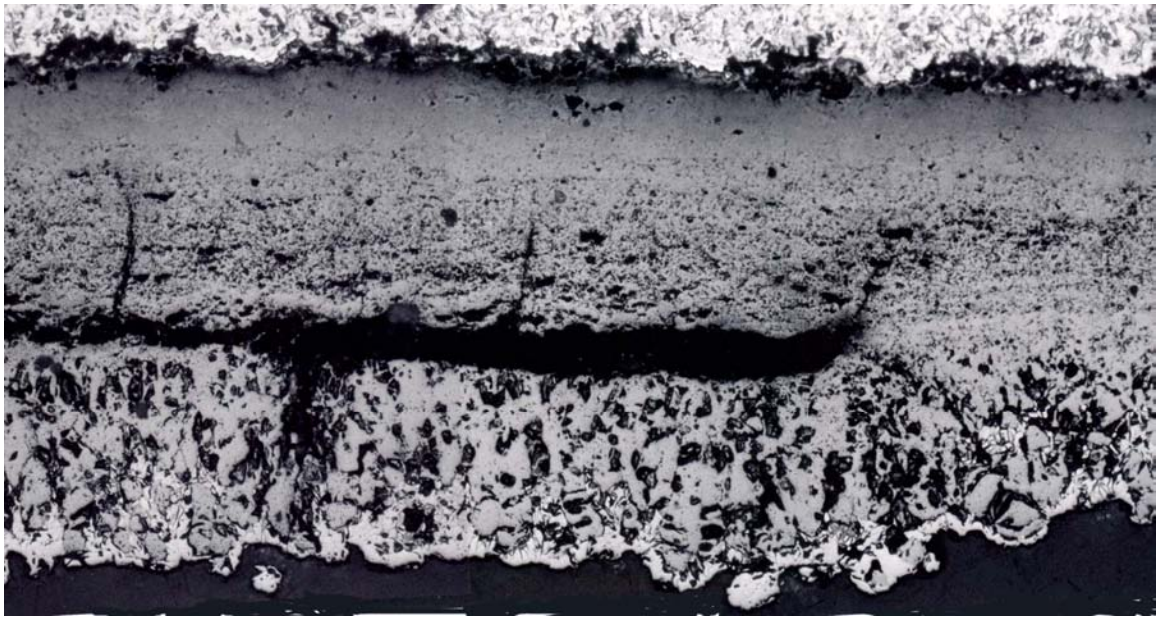

Figure 9 – Severe delamination and the early stages of blistering in the steamside oxide scale.

Figure 10 – Visible appearance of blistered and partially exfoliated steamside oxide scale

Unusual features were also observed in the fireside scale. In particular, in regions with ash buildup, the oxide thickness was multilayered and very thick. In regions with no ash buildup the fireside oxide was significantly thinner, had an irregular interface with the tube material and exhibited a relatively deep dealloyed layer in the underlying tube material (Figure 11).

The causes and significance of the steamside and fireside oxide characteristics are troublesome and need further research to fully understand. At this juncture it is not clear if the thick, multilaminated scale is a result of wustite formation or is a result of the growth of a scale with less protective properties than the normal spinel-magnetite-hematite layers.

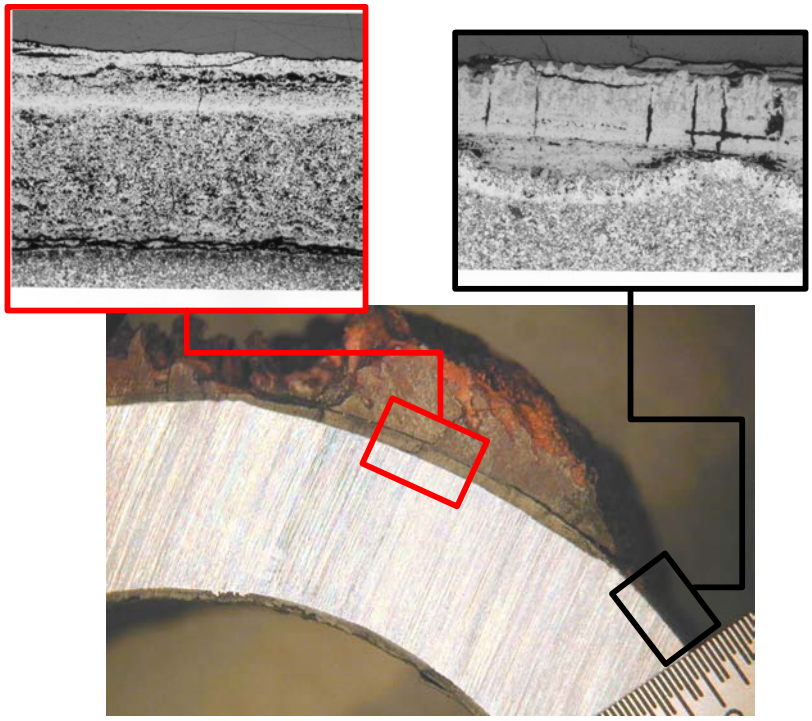

Figure 11 – Fireside oxide scale and near-surface dealloying beneath and away from ash buildup. Underneath the ash deposit the oxide scale is more than twice as thick, exhibits a multilayered morphology (suggesting wustite growth) and grows with a straight interface and no significant dealloying of the underlying tube metal. At locations without ash buildup the oxide scale is thinner, has an irregular interface with the base metal, and exhibits a relatively deep dealloyed layer in the base metal.

TEMPERATURE PROFILES AND PRELIMINARY REMAINING LIFE ASSESSMENT

Based on the steamside scale thickness and service hours it was estimated that the failed tube circuit had a persistent outlet steam temperature near 1100°F (593.3°C). It was estimated that the tube metal temperature at the rupture location had increased from around 1100°F (593.3°C) to more than 1250°F (676.7°C) as a result of the buildup of the steamside oxide scale. Based on the design pressure of 2075 psig (14.41 MPa) and specified dimensions of 2-inch (50.8 mm) outside diameter x 0.270-inch (6.86 mm) minimum wall the design stress is approximately 6.9 ksi (47.6 MPa) and the design temperature of T91 is approximately 1153°F (622.8°C). It was therefore concluded that the tube first entered service operating at tube metal temperatures below the design temperature but after relatively rapid growth of steamside scale operated for a considerable period of time at metal temperatures well above the design limits.

The reason for the failure occurring in Row 6 was reviewed. The critical design attributes that control the pressure drop, flow rate and temperature in each tube circuit were evaluated (Table 2). It was found that although Row 5 had the longest gas touched length, it had an outlet steam temperature approximately 12°F to 15°F (6.7°C to 8.3°C) cooler

than Rows 6 and 7. Due to the presence of flow orifices, Rows 6, 7, and 8 had the largest equivalent hydraulic lengths. Rows 6 and 7 had very similar outlet temperatures; whereas, Row 8 runs about 10°F (5.6°C) cooler. This suggests that a variation in heat flux through the bundle has an important influence on the heat pickup within individual circuits. Even more profound variations in heat flux across the unit were present as was indicated by side to side temperature variations which varied by more than 175°F (97.2°C) (Figure 14).

Table 2 – Design Attributes of Element 41, Rows 5, 6, 7 and 8

Row	Gas-touched length, ft / m	Heat absorbing surface area (at OD/ID), ft2 / m^2	. Equivalent hydraulic length, ft / m	Estimated Effective Outlet Penthouse Tube Temperature Compared to the Row 7 Value, °F / °C
5	**178.5 / 54.4**	**93.5/68.0 / 8.69/6.32**	210.0 / 64.01	-14.6 / -8.11
6 (circuit which had a LTO-C failure)	176.1 / 53.7	92.2/67.1 / 8.57/6.23	**218.8 / 66.69**	-2.9 / -1.6
7	174.2 / 53.1	91.2/66.5 / 8.47/6.18	216.5 / 65.99	0 / 0
8	174.9 / 53.3	91.6/66.8 / 8.51/6.21	218.7 / 66.66	-10.4 / -5.77

Based on the evaluation of selected Glen Lyn T91 SSH tube samples EPRI prepared the following preliminary remaining life chart for AEP (Table 3). This was a very practical tool to evaluate the health of the T91 SSH tubes and plan future actions.

Table 3 - Bounding Life Estimates made using EPRI TUBELIFE III

Steamside oxide thickness, inch / mm	**Estimated Remaining Life, hrs**
0.018 / 0.457	119,000
0.020 / 0.508	75,000
0.022 / 0.559	45,000
0.024 / 0.610	24,000
0.026 / 0.660	9,000

CONDITION ASSESSMENT OF THE SUPERHEATER

Ultrsonic oxide and wall thickness measurements of selected superheater tubes at Glen Lyn were performed to identify the extent of the damage. The nondestructive examination included the penthouse tubing and furnace tubing at several different locations in the section (Figures 12 and 13).

The steamside oxide thickness measurements made on the penthouse tubes are used to estimate the effective (time integrated) steam temperature of each individual tube entering the outlet header. The oxide scales in the penthouse tubes ranged from 0.0048-inch to 0.0195-inch (0.122 mm to 0.495 mm) (Figure 12). The hottest tube rows were found to be the two middle rows (Rows 6 and 7). Rows 6 and 7 temperatures were estimated to average 1054°F (567.8°C) and 1057°F (569.4°C), respectively. The outer two rows (Rows 5 and 8) were estimated to be over 10°F (5.6°C) cooler on average than the two middle rows of tubing. The penthouse tubing steamside oxide thickness measurements indicated that a significant temperature profile variation existed across and through the SSH bundle.

Much thicker steamside oxide scales were present in the furnace at the elevation of the LTO-C failure. In this region the steamside oxide thickness ranged from approximately 0.006-inch to 0.031-inch (0.152 mm to 0.787 mm). The hottest elements were calculated to have effective metal temperatures well over 1100°F (593.3°C).

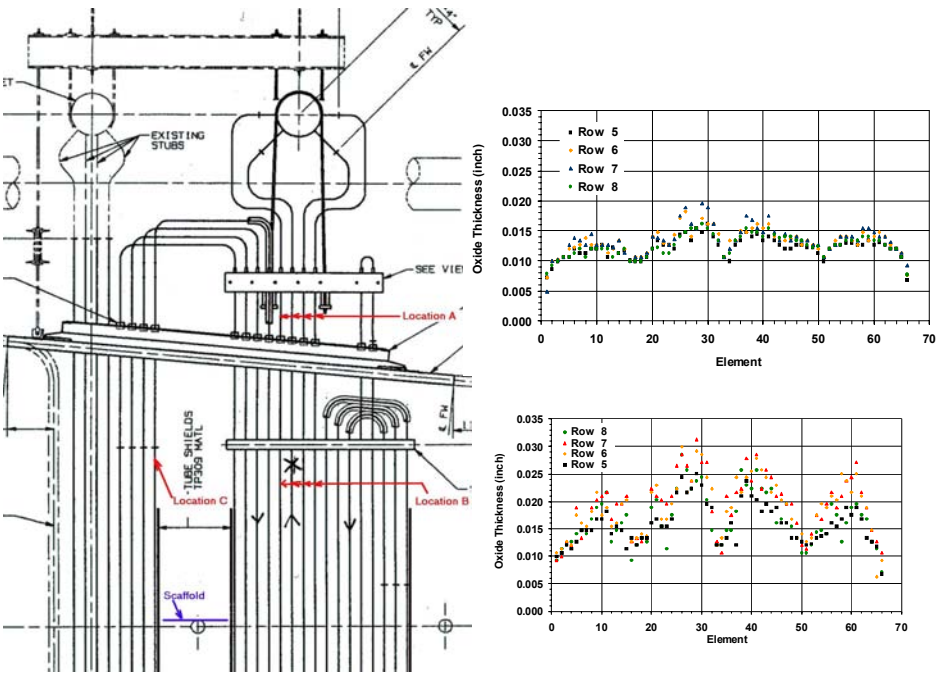

Figure 12 – Steamside oxide scale measurements made in the outlet penthouse and in the furnace at the same elevation as the LTO-C failure.

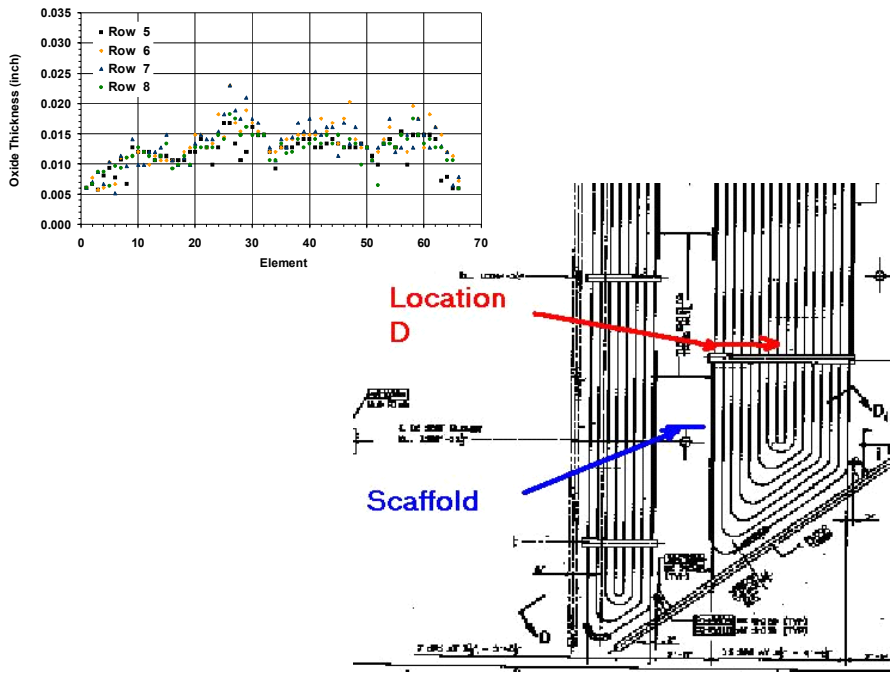

Figure 13 – Steamside oxide scale measurements made in Rows 5 through 8 at a location approximately 20 feet (6.1 m) upstream of the LTO-C failure.

The temperature estimations were made using an advanced analytical model which allows the steamside oxide growth behavior to be calibrated using unique unit and multilaminated wustite oxide layer characteristics. Data from a limited number of thermocouples were available from the unit prior to the failure. Unfortunately, these thermocouples were only located on the outer two circuits (the two coolest rows). Comparing the thermocouple data (collected from the unit in 2002 while the unit was operating with a bulk main steam outlet temperature of 1050°F (565.6°C)) to the oxide scale based effective temperatures, a very good correlation can be observed. Figure 14 shows these comparisons between the outermost rows for the thermocouples and oxide scale based temperature predictions. The temperature profile shows low temperatures along the side walls and the division wall with peaks around Elements 25 through 31 and Elements 36 through 46.

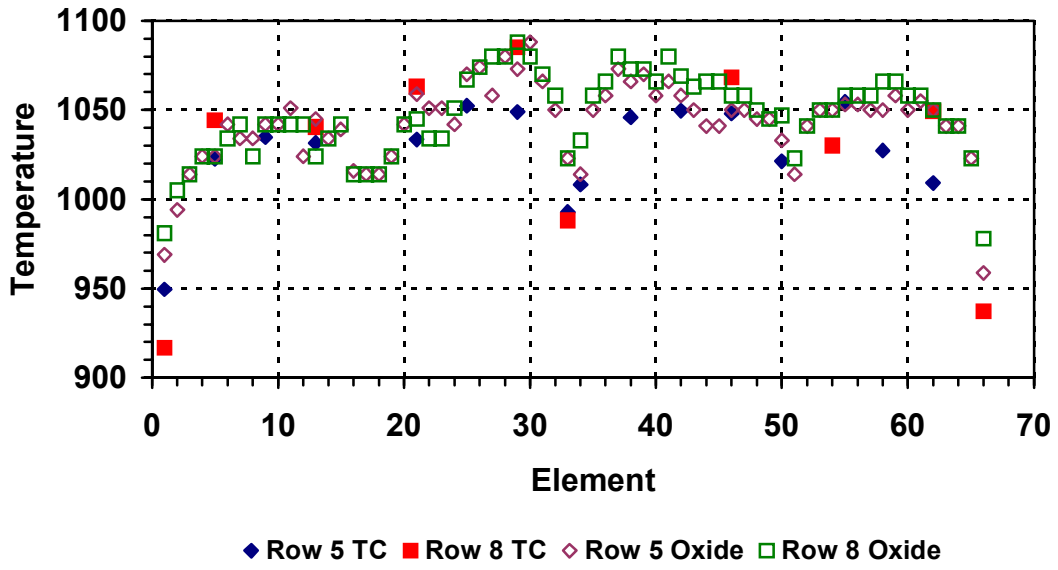

Figure 14 - Temperature Comparison (thermocouple data at a bulk outlet temperature of 1050°F (565.6°C) to oxide scale data)

A cross plot of the temperature comparisons (Figure 15) shows that the oxide scale based temperature estimates were typically within approximately +25°F to -10°F (+13.9°C to -5.6°C) of the thermocouple data. It should be noted that the thermocouple data were averaged over a one month period in 2002; whereas, the oxide data were the result of 61,000 hours of operation.

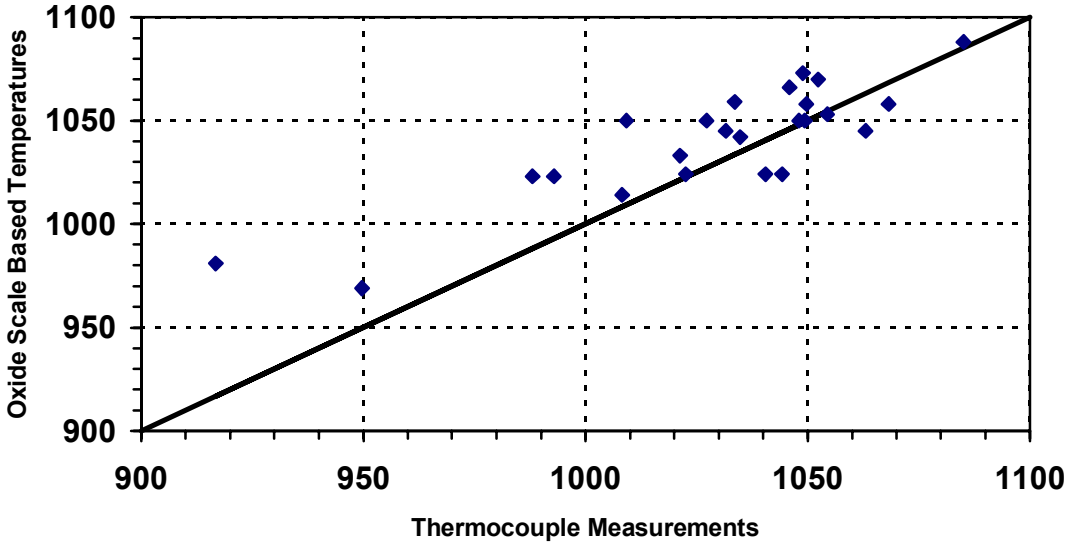

Figure 15 - Cross Plot of Instantaneous Tube Metal Temperatures (Thermocouple Data) made at a bulk outlet steam temperature of 1050°F (565.6 °C) and the Long-term, Effective Tube Metal Temperature Inferred From Measured Steamside Oxide Scale Thickness

Ultrasonic wall thickness measurements made at the elevation of the LTO-C failure revealed that all but about a dozen locations had wall thickness values greater than the specified minimum wall thickness of 0.285-inch (7.24 mm) (Figure 16). An evaluation of the relationship between the steamside oxide scale thickness and the estimated wall loss (Figure 17) revealed that the wall loss was in the range of ½ to 3 times the steamside oxide thickness. This suggests that the primary wall loss mechanism is steamside and fireside oxidation. No evidence of accelerated fireside coal ash corrosion or erosion was found.

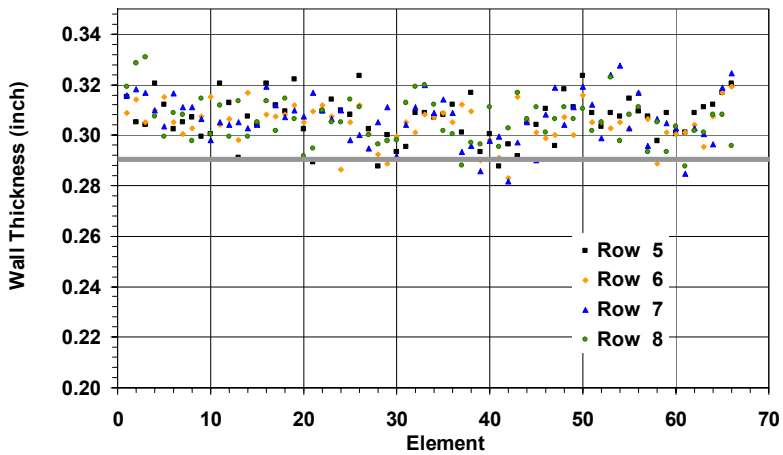

Figure 16 – Wall thickness measurements made at the elevation of the LTO-C failure. The tube on Rows 6 and 7 of Element 41 had the thinnest measured wall thickness and were approximately 0.05-inch (1.27 mm) less than the specified minimum wall thickness of 0.285-inch (7.24 mm).

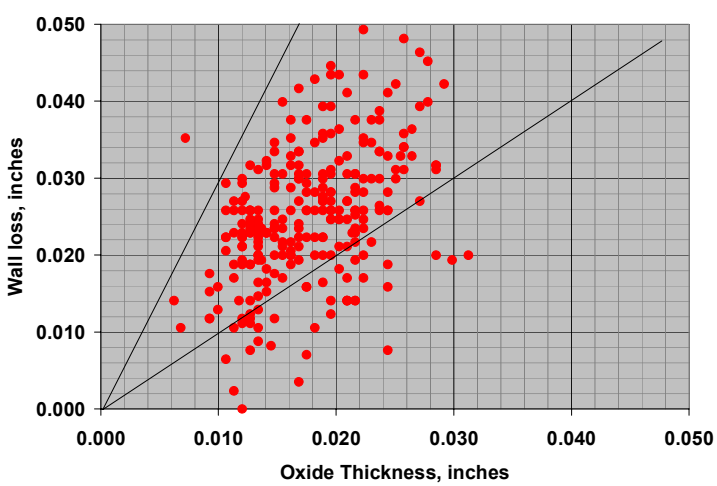

Figure 17 - Wall loss versus steamside oxide thickness for Rows 5 through 8 at the elevation of the LTO-C failure. Since the wall loss rate is no more than three times the steamside oxidation rate, the active wall loss mechanism is probably primarily steamside and fireside oxidation rather than coal ash corrosion or erosion.

REMAINING LIFE ASSESSMENT OF T91

The nondestructive examination data, the characteristics of the LTO-C failure and available thermocouple data were used as input into remaining life predictions. The data indicated that several tubes were at or near end of life at the failure location. Ultrasonic measurements were made at the elevation of the LTO-C tube failure on every outlet circuit through and across the boiler. A total of 264 tube locations were measured. Of these, fourteen were found to be at end of life with another seven tubes with less than 25,000 hours of remaining life. These calculations were based on assumed lower bound material properties. Figure 18 shows the remaining life predictions for the location of the tube failure.

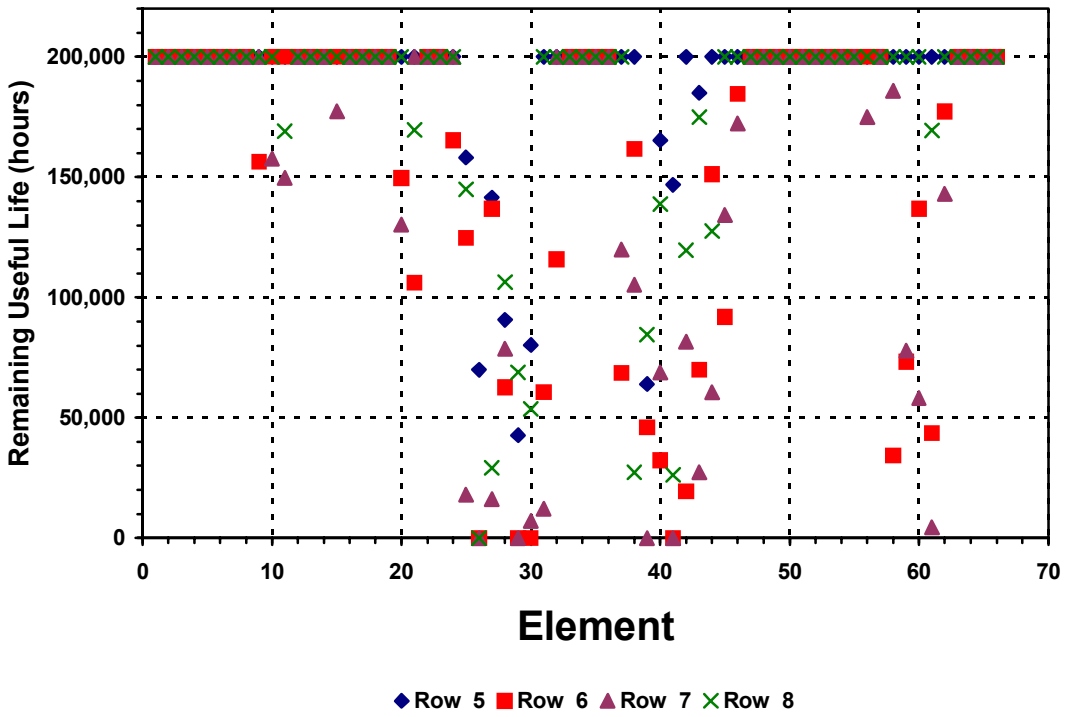

Figure 18 - Remaining Useful Life Estimates at Failure Elevation

CORRECTIVE ACTIONS

To avoid near term failures prior to modifications to be performed during a longer term planned outage, portions of five circuits including the circuit containing the LTO-C failure were replaced during the outage. The sections of tubing that were immediately replaced all had visible evidence of steam wash damage caused from the tube leak.

After replacing the steam washed sections of tubing and returning the unit to service, engineering evaluations were performed to determine the most effective correction action for the superheater. The objective of the corrective action was to optimize the life of the existing superheater. No specific life target was assumed.

Based on the results of the evaluations, AEP elected to replace sections of approximately fifty tube locations during the May 2004 outage along with the implementation of a steam flow redistribution modification. The fifty tubes were replaced from just inside the penthouse down approximately twenty two feet into the furnace on the outlet tubing. These tube locations were cataloged for future use in an expected EPRI study on life assessment of T91. The locations of the tube replacements are shown on Figure 19 which is a plan view of the outlet tubes just below the roof.

The corrective action engineering evaluations included installation and monitoring of more penthouse tube thermocouples, remaining life assessment using the steamside oxide surveys, metallurgical evaluation of a section of tubing removed from Pendant 40 of 66/ Row 1 of 4 of the outlet leg, and thermal hydraulic modeling of the tube circuits.

It was found that a combination of selected tube replacement, moderate reduction in bulk steam outlet temperature (from 1050°F to 1030°F (565.6^{o}C to 554.4^{o}C)) and steam flow redistribution (to reduce the steam and metal temperatures in the hottest tube circuits) would provide the most cost effective means for optimizing the reliability and life of the superheater.

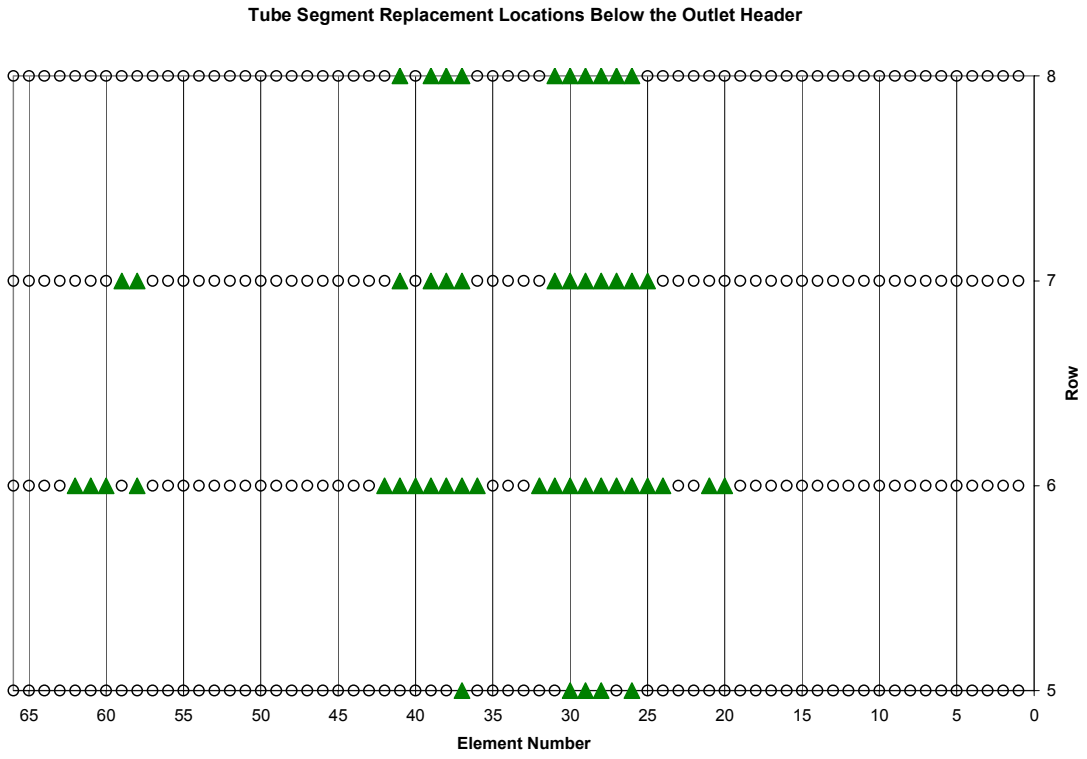

Figure 19 - Tube Replacements in Glen Lyn 6 SSH During 2004 Outage (Replacements were made From the Penthouse Down into the Furnace on these Circuits Approximately 22 Feet in Length).

Various groupings of corrective action options were considered to optimize the life of the Glen Lyn 6 superheater. The most cost effective option was determined to be replacement of the most severely degraded sections of tubing combined with steam flow redistribution. The steam flow redistribution involved installation of fifty five steam flow controllers (SFC) into selected circuits near the inlet header. The installation was near the existing orifice plates and in fifteen locations included removal of the existing orifice and replacing with an SFC. Two SFC sizes were designed and installed. These SFC were machined from F22 material and shipped to the plant for installation. The installation (Figure 20) was performed during the May 2004 outage.

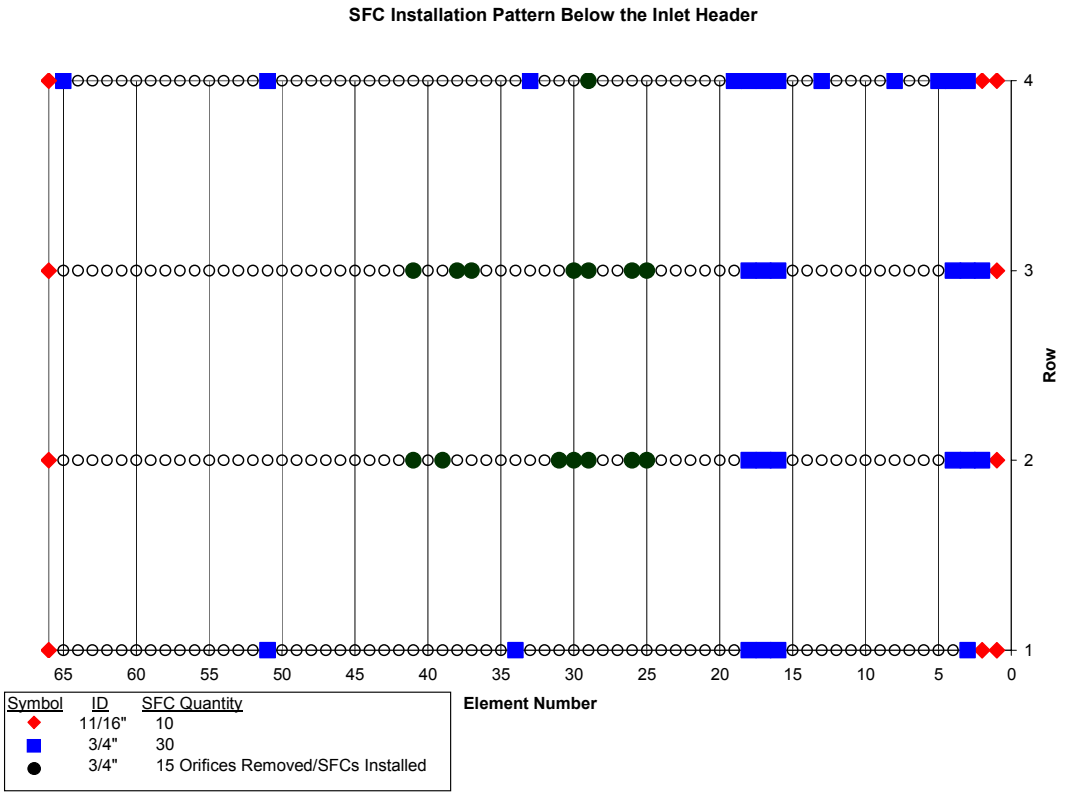

Figure 20- Cross-section of Inlet Header Tubing Showing Steam Flow Controller Installation

The steam flow controller installation was predicted to change the temperature profiles and remaining life of the component. The rate of LTO-C damage in SA213 T91 material is very sensitive to temperature. For every 18°F (10°C) change in temperature the rate of damage will change by a factor of approximately 2.5[6]. The temperature profile before and after steam flow redistribution is shown in Figure 21. The peak temperature was predicted to be reduced from 1119°F to 1084°F (603.9°C to 584.4°C) as a result of steam flow redistribution. In addition, the temperature range, minimum to maximum, was reduced by 64°F (35.6°C). Figure 22 shows the predicted failure projections for the superheater section over the next 200,000 hours of service. The time to first failure was increased by 110,000 hours and sixty failures were prevented compared to if no action was taken. The failure predictions show an almost linear failure rate over the time frame. This is quite unusual and appears to be due to the unusual oxidation growth in the T91 material. The rapid growth rates projected by the model indicate that the failures would accelerate linearly due mainly to the oxidation rates projected.

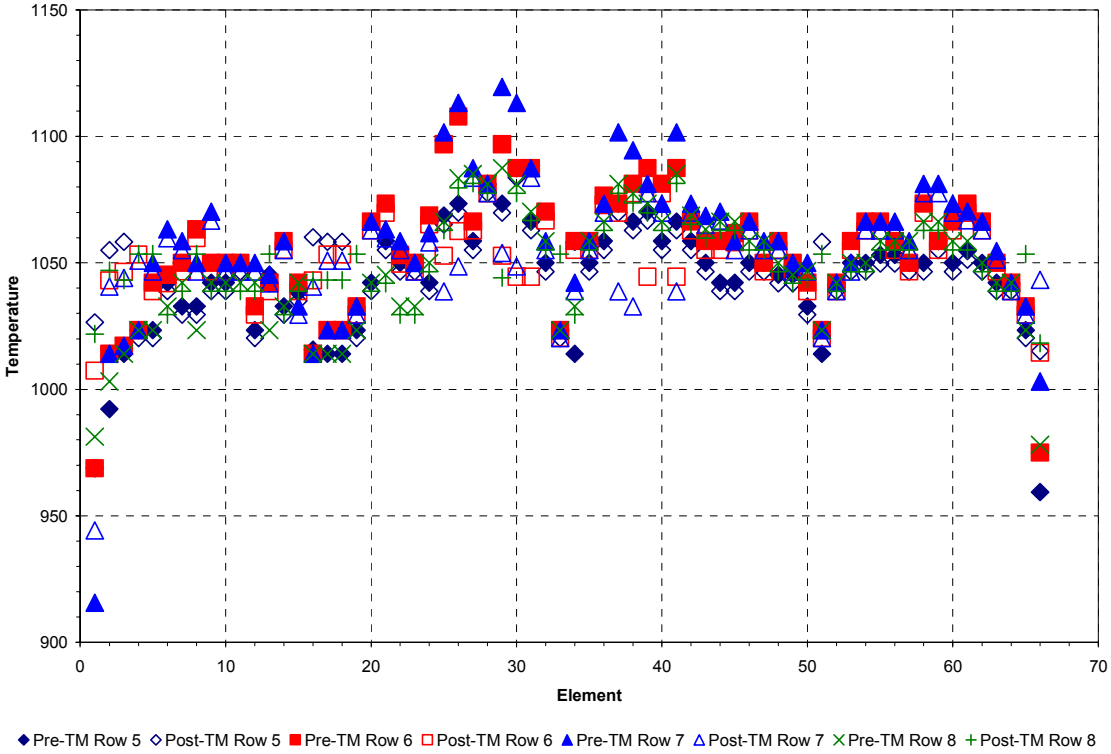

Figure 21 - Predicted Temperature Profile Before and After Steam flow Redistribution; Peak Temperatures were Reduced by 35°F (19.4°C) and the Range from Minimum to Maximum was Reduced by 64°F (35°C).

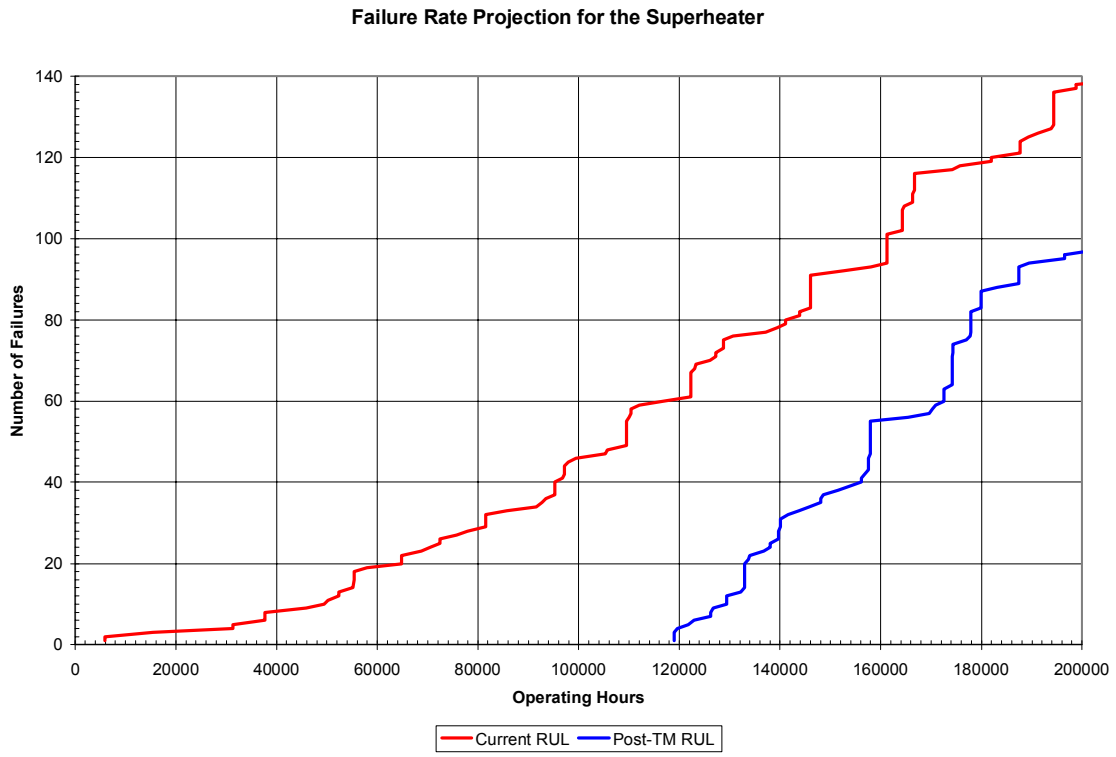

Figure 22 - Expected Failure Projections Before and After Replacement of Selected Tubes and Steam flow Redistribution.

SUMMARY

A metallurgical evaluation of a LTO-C rupture of a T91 SSH tube resulted in the recommendation to perform comprehensive condition and remaining life assessments of the SSH. These assessments revealed that numerous sections of tubing were near end of life and needed to be replaced to assure the reliability of the unit. To optimize the life of the existing and replaced sections of tubing engineered steam flow controllers were added to selected inlet tubes to smooth out the steam temperature profile across the tube bundle.

Metallurgical evaluations of selected sections of tubing also revealed a number of unanticipated and undesirable features in the steamside and fireside oxide scales. It appears that growth of thick, multilayered steamside oxide scale may have decreased the life of the tubing from an anticipated life of more than 20 yrs to a scant 8 years of service. Active and planned EPRI research projects will attempt to provide a more thorough understanding of these characteristics, and their control and/or consequences.

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Stress Corrosion Cracking of Creep-Strength Enhanced Ferritic Steels

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ABSTRACT

The discovery of pre-service cracks in boiler and steamline components fabricated from Grade 91 material has re-focussed attention on an old source of concern with regard to higher-chromium martensitic steels. Since the 1930's, it has been well known that the 400-series martensitic stainless steels require special care during fabrication. But with the advent of the latest generation of higher-chromium creep-strength enhanced martensitic steels, led by Grade 91, the power generation industry in the US has been forced to relearn some very painful lessons of the past. In particular, the industry has had to come to terms with the fact that the higher-chromium alloys require a greater level of care in all phases of processing when compared to the traditional carbon and low alloy boiler grades. One of these lessons is the fact that the timing of the various processing steps can be just as critical in producing serviceable components as the control of the steps themselves.

Recent experience has shown that the higher-chromium martensitic steels, when left in the untempered or under-tempered condition, are susceptible to stress-corrosion cracking in what would otherwise be considered "benign" environments. A comparison of recent cases of stress-corrosion cracking in Grade 91 boiler components found no common factors with regard to fabrication history, other than the fact that in each case the components had been left in a hardened condition for an extended amount of time before the final tempering post fabrication heat-treatment was applied.

This paper presents three cases where stress-corrosion cracking had occurred before components fabricated from modified 9Cr material were placed into service. Details regarding the metallographic analysis of the samples are presented. In addition, there is a discussion of the form of the stress-corrosion cracking, and recommendations for future study are presented.

INTRODUCTION

Since the introduction of the creep-strength enhanced martensitic steels, and particularly Grade 91, to the US power generation industry, it has become apparent that the tolerances established for processing the traditional carbon and low alloy boiler steels, such as Grade 22, are inadequate

for the newer materials having 9% to 11% chromium. For example, for these creep-strength enhanced martensitic steels, tighter tolerances for thermal treatments are essential if the specific condition of microstructure required to produce satisfactory mechanical properties is to be achieved. Other effects of fabrication, such as the straining due to cold bending, have been shown to degrade the creep properties of Grade 91 (9Cr-1Mo-V) significantly when critical levels of strain are exceeded, so that re-heat treatment is necessary [1].

Another fabrication concern that has received attention has emerged from the realization that the higher-chromium creep-strength enhanced martensitic steels can be highly susceptible to stress-corrosion cracking (SCC) when left in a hardened or under-tempered condition. This potential danger should have been recognized, since the susceptibility to SCC was well known in the earlier high chromium alloys. For example, in the 1930's the susceptibility of the 400-series stainless steels to stress-corrosion cracking in the as-welded or hardened condition necessitated the implementation of special rules for fabrication. Using these rules, in the 1940's Combustion Engineering's Chattanooga manufacturing facility successfully processed 30,000 tons of AISI 430 plate to fabricate ASME code pressure vessels and rail car tanks needed to support the munitions industry.

By the 1950's it had been established that T9 (9Cr 1Mo) tubing also was susceptible to stress-corrosion cracking when left in the hardened or as-welded condition, and fabrication procedures in place at that time reflected this knowledge, reinstating the fabrication approach developed during the 1930's. More recently, the SCC susceptibility of the European precursor to the Grade 91 alloy, X-20 (X 2012CrMoV 11-1 steel) was widely reported in the technical literature. For example, Kalwa, Haarmann and Janssen reported in 1984 [2] that the material in the hardened or as-welded condition is highly subject to stress corrosion cracking when exposed to non-specific aggressive agents, which were reported to include both condensate and rain. One fabrication practice that was reported to be a particular problem was the use of sand filling for making hot bends in pipe. The sand fill reduces the transformation cooling rate, resulting in an increase in grain boundary carbides and hence a greater susceptibility to stress corrosion. Precautions also were recommended to avoid detrimental effects from transformation of retained austenite. In response to these several concerns, the authors recommended that the time during which the material was kept in the hardened or under-tempered condition be minimized, and if storage was necessary, that the material be kept dry. They further recommended that the tempering or post-weld heat treatment be performed as soon as possible after normalizing or after welding, since the material is insensitive to the SCC when properly tempered.

A thorough and detailed explanation of the physical basis for the susceptibility to intergranular SCC in the higher-chromium martensitic grades, such as X20, was provided by Doig, Chastell, and Flewitt based on work undertaken at the former CEGB in the late 1970's [3]. They characterized the degree of chromium depletion that developed along prior austenite grain boundaries depending on the degree of tempering and demonstrated the importance of the magnitude of the difference in chromium content between the depleted grain boundary region and the "unaffected" matrix in determining susceptibility to SCC. This dependence of the susceptibility of the X20 material to SCC on the degree of tempering is shown in Figure 1. Based on their model, as well as the work of several other investigators, it is apparent that the highest degree of susceptibility to SCC will occur, not immediately after rapid and continuous

transformation to martensite, but rather after incomplete tempering of the martensitic structure at some intermediate temperature and time. This is particularly significant for the creep-strength enhanced martensitic steels, since the implementation of a hydrogen bake at a temperature of 600-800°F (or higher), which has been promoted as an effective means of preventing hydrogen delayed cold cracking of weld zones, may leave the material particularly vulnerable to SCC. They also discuss the potential pitfalls in using hardness as a direct indicator of SCC susceptibility for this class of alloys. They argue that, since susceptibility is influenced more directly by the difference in chromium content between the depleted grain boundary and the matrix, hardness cannot reliably indicate susceptibility at intermediate levels of tempering, because the relationship between hardness and relative chromium distribution is, at best, indirect. This finding is illustrated in Figure 2, showing clearly that SCC susceptibility is not related directly to hardness.

STRESS-CORROSION CRACKING OF GRADE 91

While the susceptibility to stress-corrosion cracking in Grade 91 should not have been unexpected, some specialists had assumed that this new grade would exhibit a decreased susceptibility to SCC because both the carbon and chromium contents and the maximum hardness of the alloy were not as high as that for the X-20 alloy. Service experience to date has indicated that this assumption, if true to any degree, is overly optimistic.

As discussed above, the basis for the susceptibility of the higher chromium martensitic steels to SCC is the fact that they can become sensitized [3]. In the process of sensitization, chromium compounds precipitate along the prior austenite grain boundaries, depleting the adjacent matrix of chromium. This local chromium-depletion leaves the material susceptible to localized attack of the depleted zone, which can develop into cracking. To eliminate this susceptibility, it is necessary to redistribute the chromium in a way that minimizes the difference in the relative concentration of chromium between the grain boundary regions and the matrix. Re-diffusion of the chromium can occur rapidly during a tempering heat treatment between 1400-1450°F (760-790°C) and more slowly at lower temperatures.

This particular form of SCC is believed to differ from the hydrogen stress cracking (HSC) that has been reported to occur in a number of the high-strength steels. The HSC is related to a reduction in the flow stress of the material that occurs as a result of the concentration of atomic hydrogen generated by a corrosion reaction at the tip of the advancing crack. Just as is the case for the active path mechanism in which sensitization is the primary cause of susceptibility, for the high strength steels the susceptibility to HSC is mitigated by a sufficient degree of tempering.

In addition to the experiences with the X-20 material already cited, laboratory testing has produced stress-corrosion cracking in Grade 91 material. Iseda, Sawatagi and Masuyama [4] reported in 1991 that the susceptibility of Grade 91 welded joints to stress-corrosion cracking was dependant on both the microstructure and the environmental conditions. Specifically, the martensitic steels were susceptible to stress-corrosion cracking in both a 10%NaOH solution and in pure water, if the tempering temperature for a short holding time was lower than 1200-1300°F (650-700°C). Cracking of the under-tempered Grade 91 material occurred when the steel was exposed to 100ppm Cl^-, independent of the tempering temperature.

With regard to the environment necessary to foster SCC in these higher-chromium martensitic steels, it has been reported that if the material is not sufficiently tempered then the component is vulnerable to stress-corrosion cracking even in a nominally "clean" environment. This may include situations where the metal is exposed to an environment capable of concentrating low levels of contaminants. For example, a change in ambient temperature can lead to the condensation of moisture on the surface of a component. If conditions favor repeated wetting and drying of the surface, the concentration of impurities present in the condensate may be increased sufficiently to trigger the onset of stress-corrosion cracking.

Alternatively, concentration may not be necessary. Iseda et al [4] reported SCC in Grade 91 material that was exposed to pure water for 500 hours (just under three weeks); the material in this case had been under-tempered to a maximum temperature of 1300°F (700°C). In a more aggressive chloride environment, stress-corrosion cracking was reported for all under-tempered conditions. It should be noted that there is anecdotal evidence linking sulfur-bearing compounds to the stress-corrosion cracking of Grade 91 materials while in the hardened condition.

CASE HISTORIES

The following three case histories each detail incidents in which boiler components experienced stress-corrosion cracking that initiated during the fabrication process. The fabrication details (tasks and sequence) differed in each case, with the one exception that for all three cases the components were left for an extended period of time in the as-welded or in the hardened (as re-normalized) condition.

Case One – Cold Bends In Thin-Walled Tubing

The first example involves Grade 91 tubing that had been bent to form elements in replacement reheater assemblies. Prior to the cold bending, the ends of the tube sections had been swaged and the entire length of the tube then had been re-normalized. After the normalizing heat treatment, the tubes were cold bent to a 90° angle with a large radius. The bent tubes then were stored outdoors for approximately six weeks prior to final assembly. Once the elements were assembled and the attachments were welded, the completed assemblies were given a final heat treatment that served as both the tempering operation and the post-weld heat treatment (PWHT). Because of the sequence of processing, the cold bent tubes were exposed in the as re-normalized condition to local ambient conditions for an extended period of time.

During the pre-shipment hydrostatic testing of the assemblies, through-wall cracks were found in two of the bends. Cracks that did not propagate through-wall were confined to the O.D. surface of eight other tubes in the bend area. As shown in Figure 3, the cracks were located at the bend intrados where the residual stress was tensile in nature. All the cracks were oriented in the circumferential direction, and were located where the tubing had been deformed during the bending operation.

The examination of the through-wall cracks revealed that the circumferential length of the crack was greater on the O.D. surface than on the I.D. surface, suggesting that the cracking had initiated at the O.D. surface. Axial specimens were cut from the cracked bends to provide a transverse view of the cracking; these specimens were polished and etched to permit evaluation of the microstructure by optical light microscopy. Micrographs of the through-wall cracking are shown in Figure 4, while the features of the shallower cracks are shown in Figure 5.

As can be seen in the macrographs and micrographs, in each case a single major crack had initiated at the O.D. surface and propagated through the wall of the tube following an intergranular path of fracture. There was minor crack branching, but there was no evidence of secondary cracking on either the O.D. or I.D. surfaces away from the two through-wall fractures. In addition, the fracture surfaces were covered with a layer of high-temperature oxide.

The evidence uncovered during the investigation of these bent tubes led to the conclusion that during the period after the tubes were cold bent and prior to the tempering heat treatment, the tubing had been exposed to an environment that fostered the initiation of stress-corrosion cracks at points of increased tensile residual stress on the intrados of the bends. The presence of the high temperature oxide scale along the fracture surfaces was proof that the cracks had occurred prior to the final heat treatment of the entire assembly.

Case Two: T22 to T91 Transition Welds In SH Tubing For Safe Ending Of T91 to T22

The cracking discussed in this second example was detected during a routine field inspection six years after initial operation. Safe ends consisting of short sections of Grade 22 tubing had been attached to the ends of Grade 91 nipple tubes fabricated for a replacement final superheater outlet header. The purpose of the safe ends was to facilitate the field welding of the assemblies to the existing T22 elements. The safe end welds had been made using a 2-1/4Cr-1Mo filler metal. In-service field inspections of the welds joining the T91 nipples to the T22 safe ends had revealed that a large number of the welds contained circumferential cracks at the toe of the butt weld on the T91 side of the joint. Of particular significance was the fact that reports from the field indicated that on a number of the welds the visible cracking extended 360° around the circumference of the tube.

One weld that contained a crack that extended approximately 120° around the circumference of the tube is shown in Figure 6, as it appeared when received from the field. Longitudinal specimens were cut from the sample to provide a transverse view of the cracking. After preparation of the specimens, the microstructural evaluation found that at the point of initiation the cracking had propagated through the coarse-grained HAZ of the modified 9Cr material, as shown in Figure 7. This was significant because, in so doing, the crack had avoided the pronounced decarburized zone that had formed in the low alloy weld deposit immediately adjacent to the fusion boundary. (The decarburized zone is an inevitable feature of such dissimilar metal combinations, where carbon diffuses from the lower chromium material to the higher chromium material during PWHT and service).

The cracking, itself, was intergranular, with minor crack branching. As shown in Figure 7, the cracking did not follow the fusion boundary, but was wholly contained within the weld Heat-

Affected Zone. At the crack tip, evidence of a small amount of crack growth by creep-fatigue was noted, as shown in Figure 8. The crack was filled with what appeared to be a layer of high-temperature oxide scale, but it could not be determined with certainty whether the bulk of this scale had formed during the post-weld heat treatment or if it was largely the product of the six years of operation at elevated service temperatures.

A review then was made of the manufacturing history of these nipples. It was discovered that after the T22 safe ends had been welded to the T91 nipples, the nipple assemblies had been stored in the as-welded (hardened) condition for a period of several weeks prior to installation into the header and implementation of the final post-weld (tempering) heat treatment. Unlike the bends in the previous example, these tubes were stored indoors, albeit within an open fabrication shop.

During the course of the field inspections, it was initially assumed that that the cracking was related to some type of system loading; possibly creep-fatigue induced by a high bending load on the nipple, since the cracking was circumferential in orientation. However, as the information regarding the field inspection results was cataloged and reviewed, the data did not match the initial assumptions. For example, the fact that in some cases the cracking was present 360° around the circumference of the tube was inconsistent with any plausible system load influence (this assumes, of course, that it is unlikely that any stress applied to a header nipple would be perfectly axi-symmetric). In addition, examination of the metallographic sections taken through one of the failed tubes showed that the cracking did not initiate in the weaker decarburized zone adjacent to the fusion boundary, but had initiated in the much stronger HAZ of the Grade 91 tubing, a fact clearly inconsistent with the dominant influence of a mechanical load. The microstructural examination also showed that there was no trace of creep damage in the area of the cracking, such as grain boundary cavities or oriented grain boundary facet cracks. In consideration of these various pieces of evidence, stress-corrosion cracking was identified as the only plausible explanation for the damage.

Case Three – Fillet Welds of T91

During the erection of a new Heat Recovery Steam Generator (HRSG), cracking was discovered in fillet welds that were part of four steam-cooled support structures associated with the superheater harp assemblies. An overall view of the structure is shown in Figure 9, together with a close-up view of one of the cracked fillet welds. The fillet welds were designed to join the top side of 14" long x 1" thick collars to the steam piping; the collar also was attached to the steam piping on its bottom side by a "J-Groove" weld. The initial inspection had revealed single cracks in three of the four fillet welds, with the portion of the crack visible at the outer surface extending from 12-14" around the circumference of the pipe. In all three cracked welds the majority of the cracking was located at the inner toe of the last bead deposited (i.e., the outermost bead next to the collar), with the exception of one weld where, a small segment of the crack (<30% of the total length) also had propagated through the centerline of the last bead. Following the initial discovery of the cracks, the welds were ultrasonically examined in an attempt to determine their depth and orientation. Based on the results of this examination, sections were removed for metallurgical analysis.

Following suitable metallographic preparation, microstructural evaluation of the sections removed from the supports revealed microstructural features similar to those described in the two previously cited examples (Cases 1 and 2). The cracking consisted of a single dominant fracture path with minor branching from the main trunk of the crack, as shown in Figure 10. In the section that contained the full through-thickness extent of the crack, it was found that the cracking followed a single continuous front, indicating that there had not been independent crack initiation from separate locations with subsequent linkage. All cracking observed, including branching, followed an interdendritic path of fracture. Evidence of the effects of aqueous corrosion activity (local pitting – crevice corrosion) could be seen at numerous locations along the fracture path on all the cracks examined.

Similar to the other two cases discussed above, a relatively thick layer of high-temperature oxide had formed on the fracture surface of all three cracks. Also, in some areas, this scale layer was covered by a thin film of the paint that had been applied to the completed support structure prior to shipment to site. The presence of the intact paint layer on top of the scale layer constituted incontrovertible proof that the cracks had developed prior to the shop PWHT for these welds.

All components of the support structure (i.e., the riser piping and the collar) had been fabricated from Grade 91 material. The fillet welds had been made in the shop using the submerged-arc welding process with Thyssen MTS-3 (B9) wire and Marathon 543 agglomerated flux. The welding procedure specification required a 400°F (205°C) pre-heat and a two hour hydrogen-bake at 600-700°F (315-370°C) immediately following completion of the welding. With regard to these fillet welds, a review of the manufacturing records reportedly confirmed that the welds had been left in the as-welded condition for an extended period of time prior to the PWHT, and that no extraordinary precautions had been taken to control the environmental conditions to which they were exposed.

In reviewing the information described above, the only plausible explanation for the cracking in these fillet welds is that, while the welds were in the hardened condition, that is, prior to the post-weld heat treatment, the environmental conditions to which the welds were exposed triggered the initiation and propagation of stress-corrosion cracks. Of particular importance in explaining the origin of the damage is the fact that cracking occurred even though the welds were given a hydrogen-bake thermal treatment, generally believed to eliminate any risk of hydrogen delayed cold cracking. Based on experience with X20, this hydrogen bake actually might have promoted the occurrence of the stress corrosion cracking. In any case, the hydrogen bake treatment will not significantly reduce the susceptibility of the material to stress-corrosion cracking.

SUMMARY

In the three cases discussed in this paper, the components were left in the hardened or as-welded condition for an extended period of time. During that time, the components were exposed to potentially aggressive environments.

In each of these three cases, the most likely cause of the intergranular fractures observed was stress-corrosion cracking. As discussed earlier, this is a mode of damage to which the whole

family of higher-chromium martensitic steels is susceptible, if the material is exposed to aggressive environments while in the hardened or under-tempered condition. In each of these cases, the cracking occurred in material that was subjected to fabrication-related residual stresses (either due to cold-forming or welding), and then exposed to an uncontrolled environment for an extended period of time in the hardened condition. In one case, the tubes were bent and stored in the hardened condition, while in the other two cases, the weld joints were left in the as-welded condition. In all three cases, the pieces were stored for weeks before the tempering or post-weld heat treatment was applied. All available evidence indicated that the cracking occurred during this storage period.

While the three cases presented involved boiler components made from tubing or plate material, Grade 91 is also being used in the fabrication of high-temperature steamline piping. Recent reviews of new P91 piping systems installed in HRSG units revealed that a large number of the girth seam welds had been left in the as-welded condition for weeks and months before the post-weld heat treatment was completed. While no stress-corrosion cracking failures of piping welds have been reported at the time of writing, it is possible that cracks have developed at a small number of the joints. In consideration of this possibility, it is recommended that the tempering PWHT for critical welds follow immediately upon the completion of welding, and that if some delay is necessary, that the joints be kept dry until the PWHT can be applied.

While stress-corrosion cracking in steamline piping may not result in through-wall leaks that are detected by the pre-service hydrostatic test, in-service propagation of cracks due to the influence of system loads is possible. As such, it is recommended that surface examinations of existing P91 piping welds be performed, especially if the welds were left in the fully-hardened condition for an extended length of time at the time of fabrication.

RECOMMENDATIONS FOR FUTURE STUDY

Based on concerns over the susceptibility of the higher-chromium creep strength enhanced martensitic steels to stress-corrosion cracking while in the hardened or under-tempered conditions, laboratory testing is recommended to be performed to determine the roles that stress, environment and exposure time play with respect to crack initiation. For testing environments, both chloride and sulfide environments should be explored, to measure the effects on both welded and non-welded samples.

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(6) Truman, J.E., Perry, R., Chapman, G.N. *Stress-Corrosion Cracking of Martensitic Stainless Steels*, Journal of The Iron and Steel Institute, September 1964, 745-766

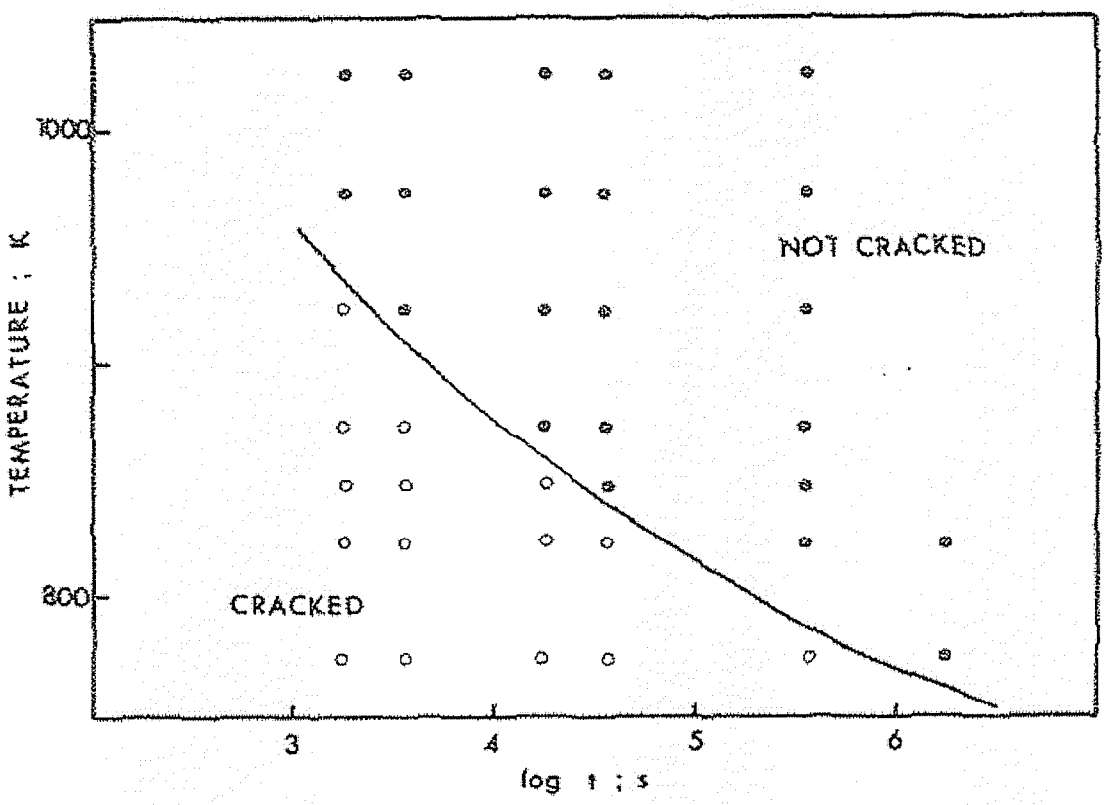


Figure 1. Adapted From Reference 3. Showing The Incidence Of Stress Corrosion Cracking Of X20 Steel As A Function Of Tempering Time and Temperature.

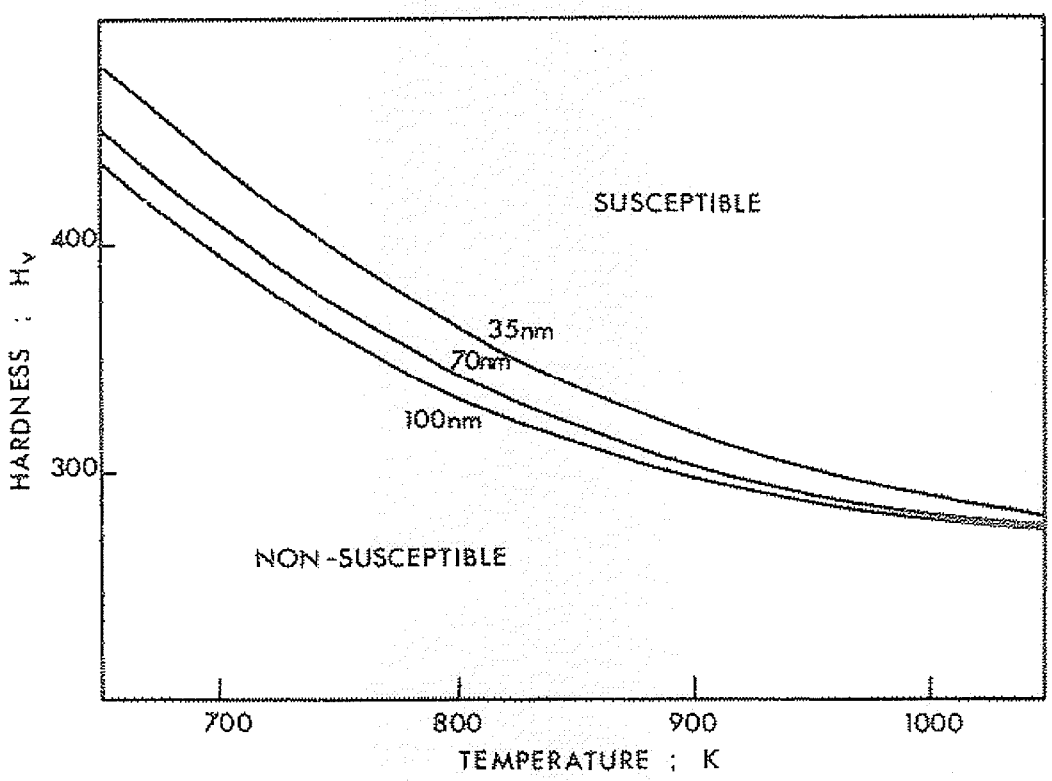
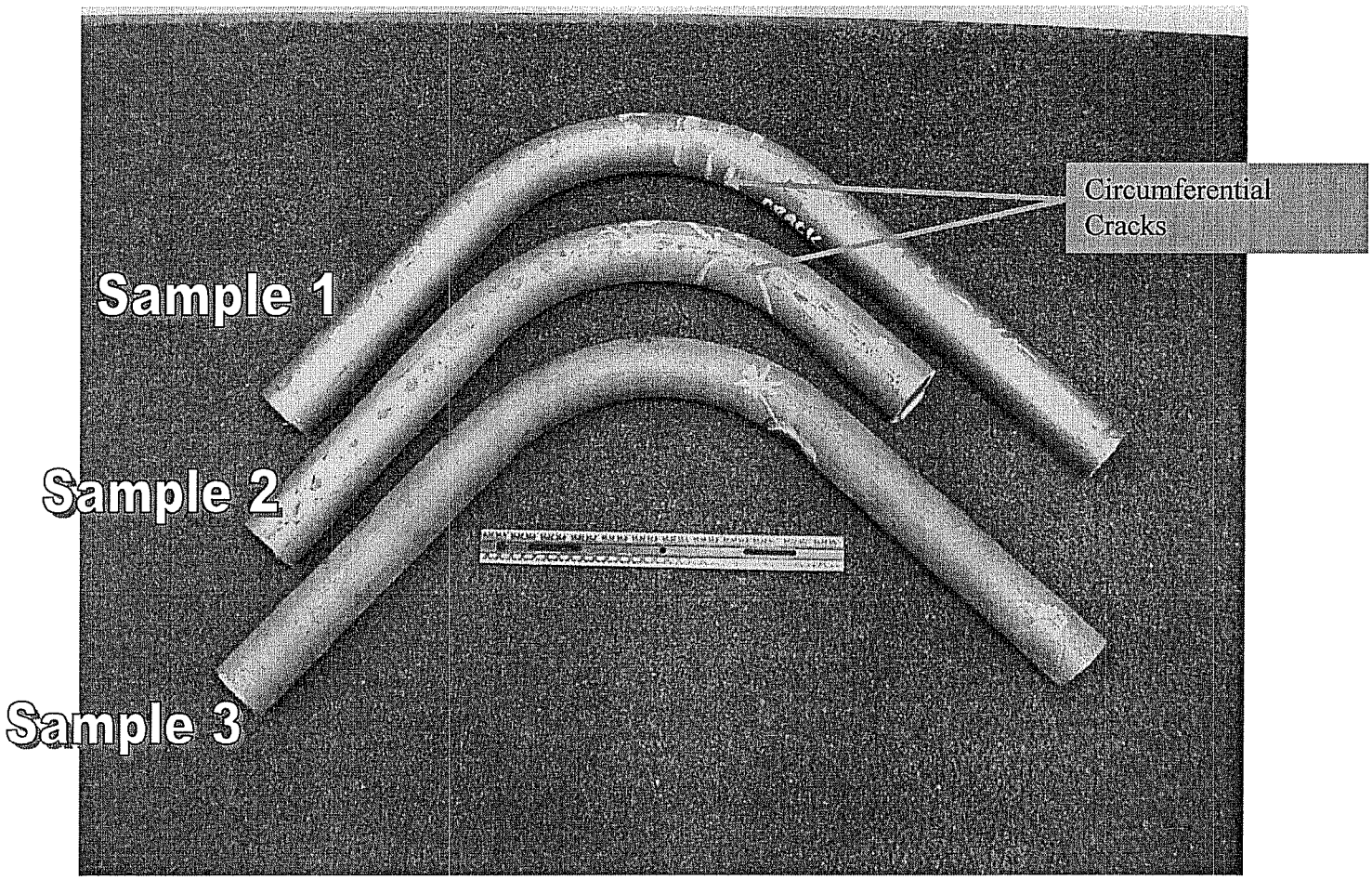
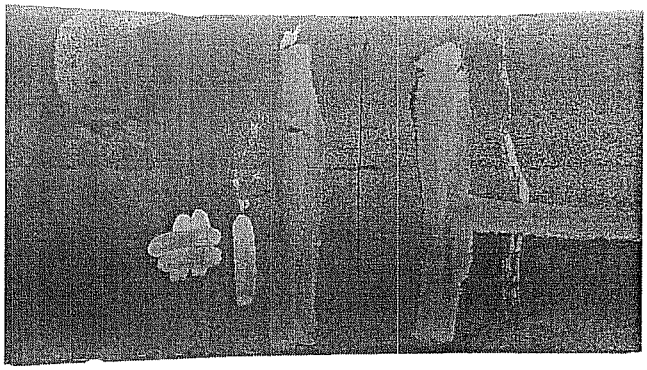
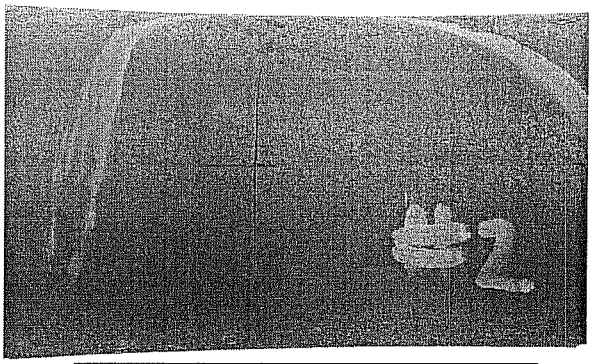


Figure 2. Adapted From Reference 3. Plots Of Hardness Level Defining The Boundary For Stress Corrosion Susceptibility As A Function Of Tempering Temperature. Different Curves Correspond To Different Assumed Values For Critical Diffusion Controlled Chromium Concentration Profile Widths = 35, 70, And 100 nm.



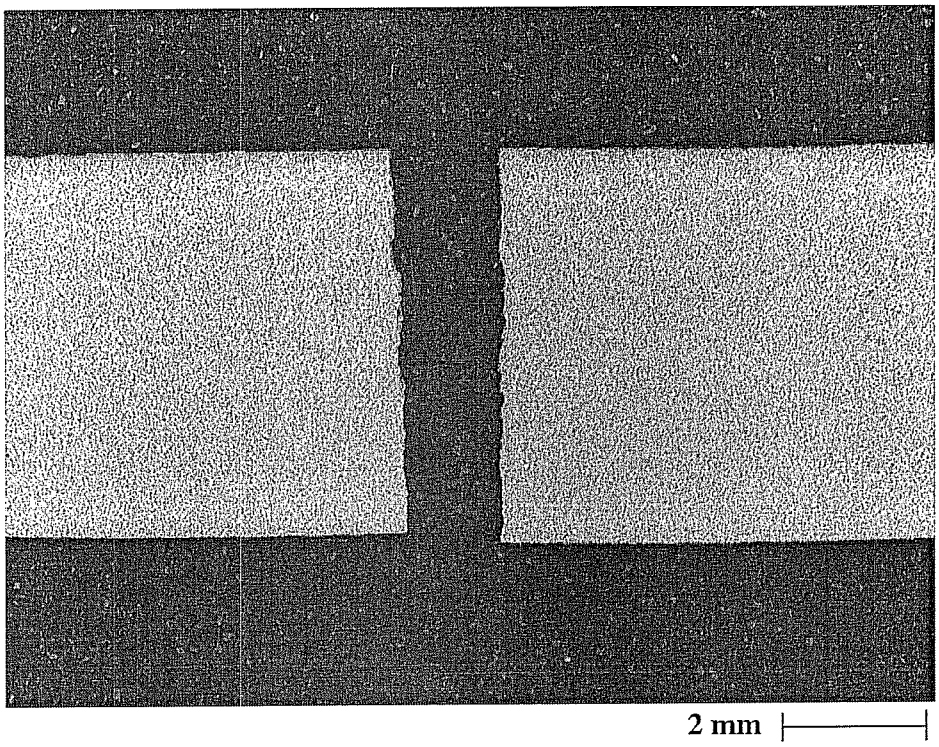


Close-up Of Crack On Sample 1



Close-up Of Crack On Sample 2

Figure 3. Case One: Documenting The Appearance Of Cracked Cold Bends In Thin-Walled RH Tubing.



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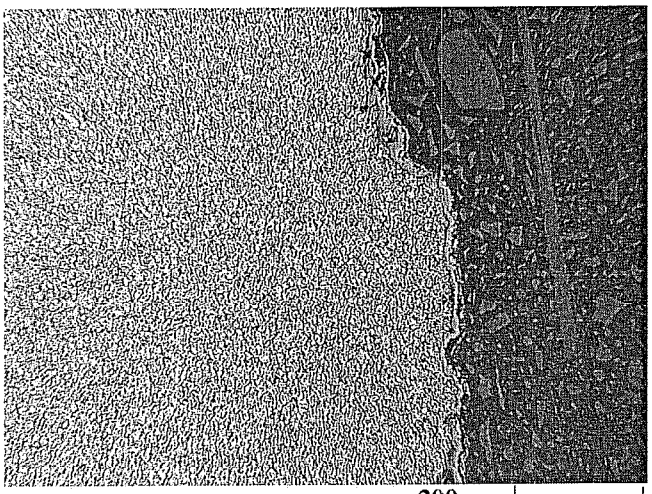

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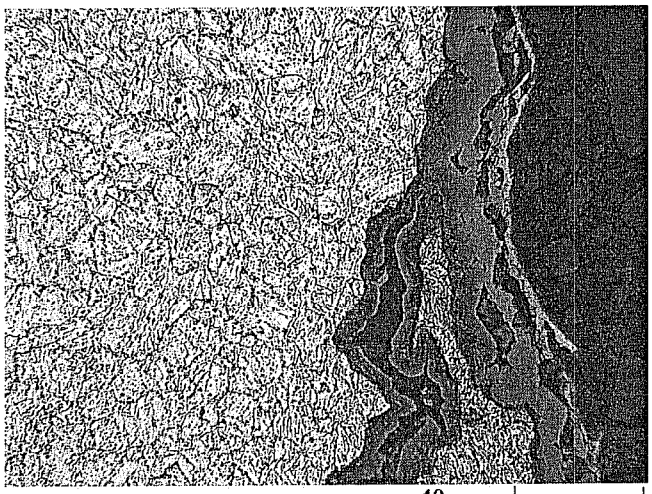

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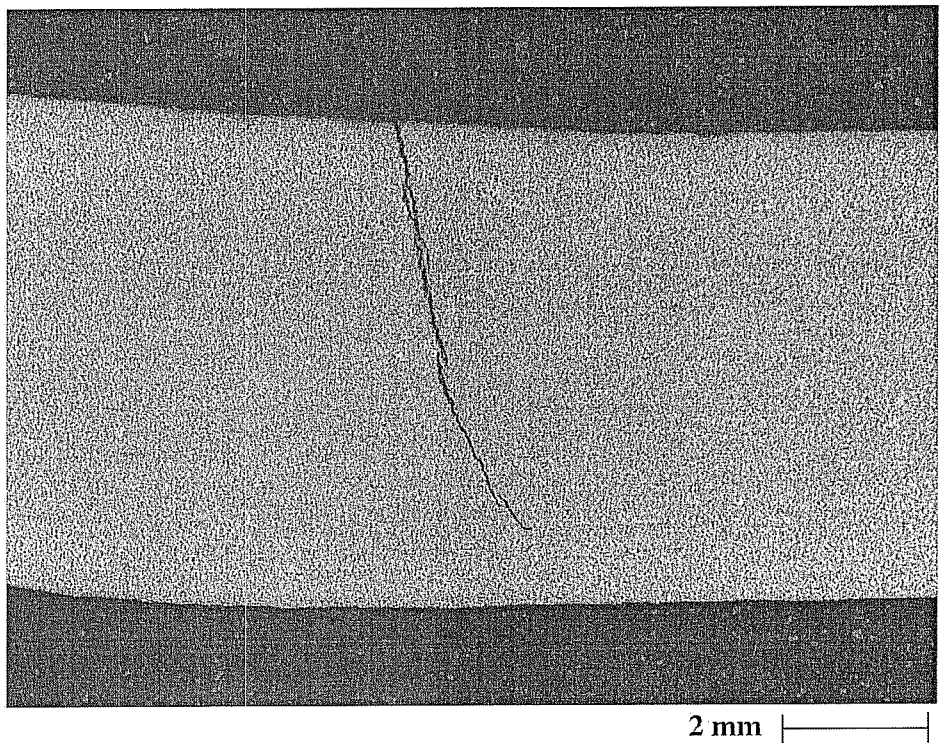
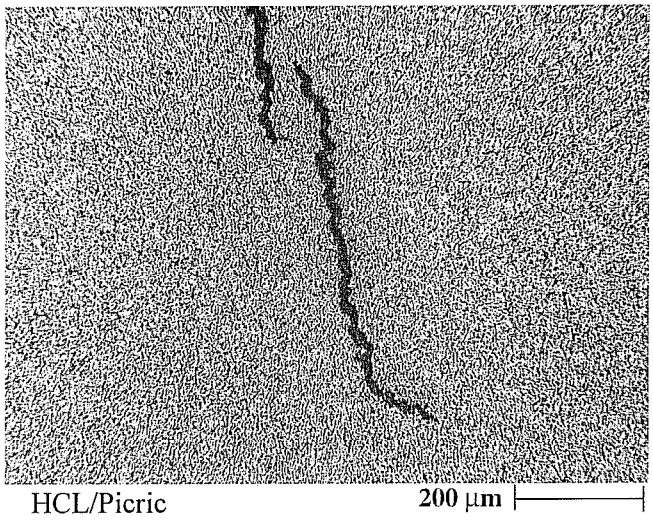
Figure 4. Case One: Documenting The Features Of The Cracking Which Penetrated The Tube Wall At The Intrados Of The Bend.





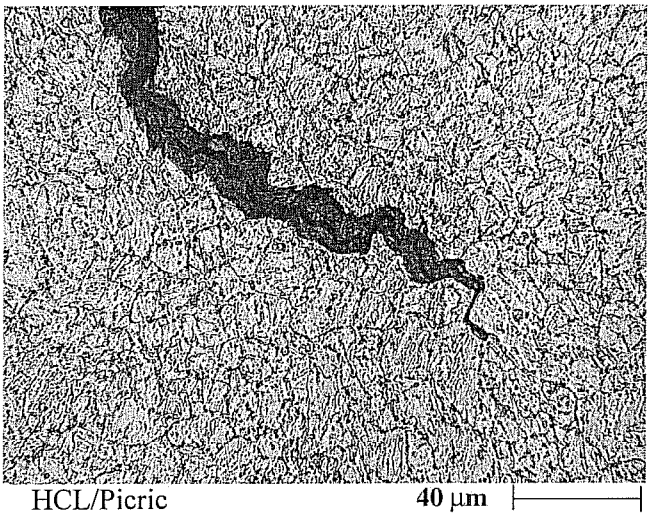


Figure 5. Case One: Documenting The Features Of Cracking That Penetrated Most Of The Tube Wall At The Intrados Of The Bend.

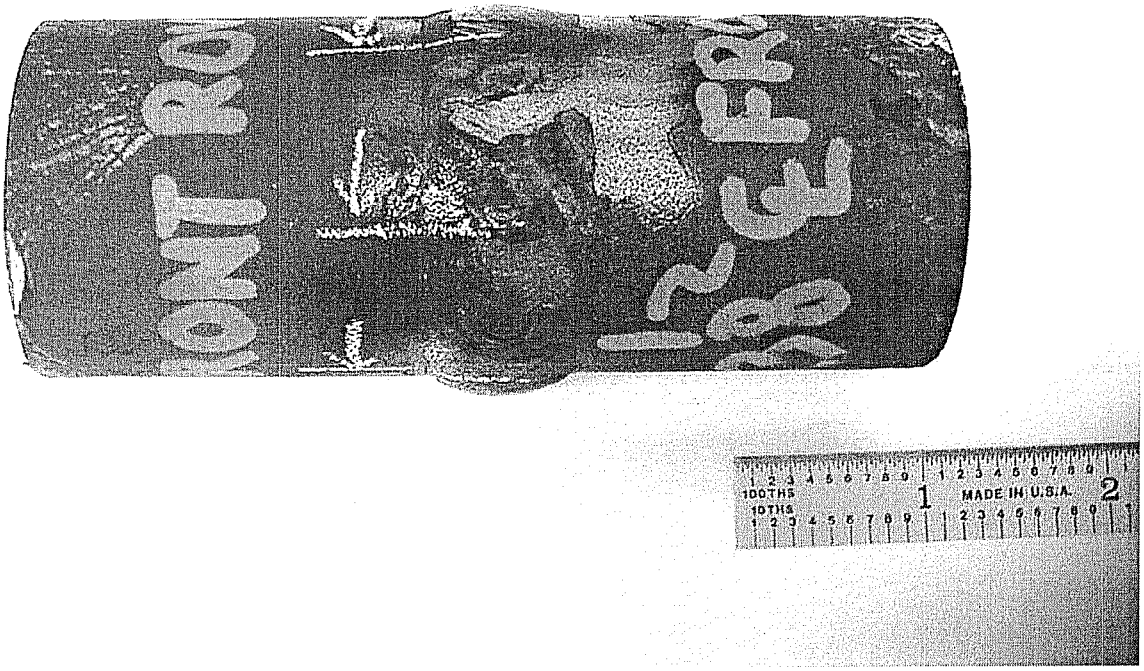
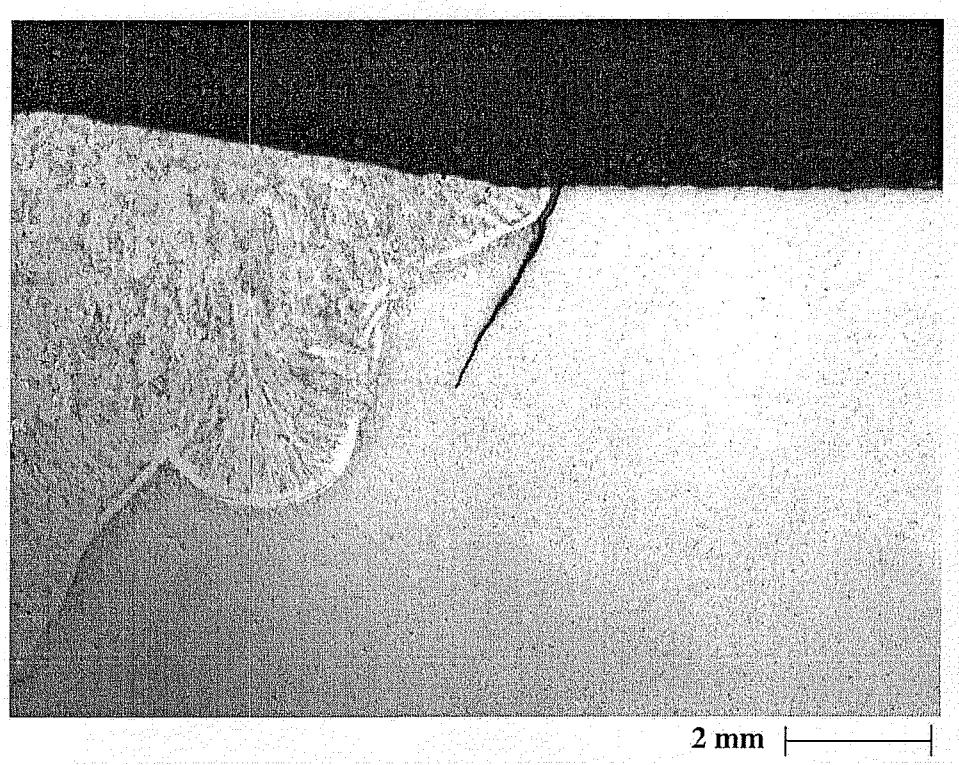


Figure 6. Case Two: Documenting The Appearance Of One Of The Transition Welds Joining A T91 Nipple Tube To A T22 Safe-End.



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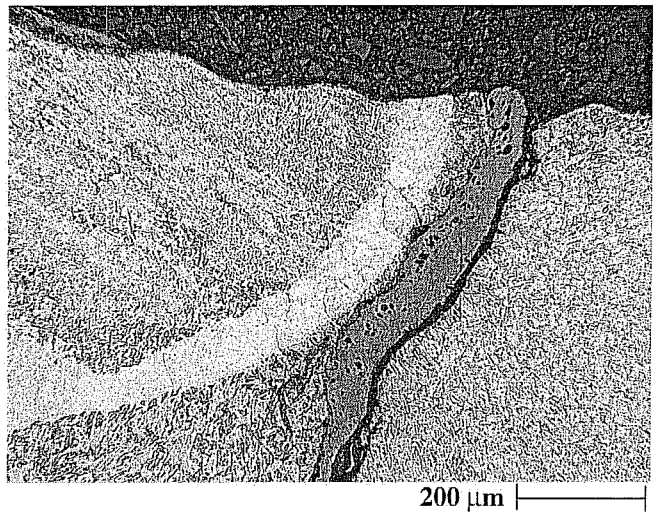

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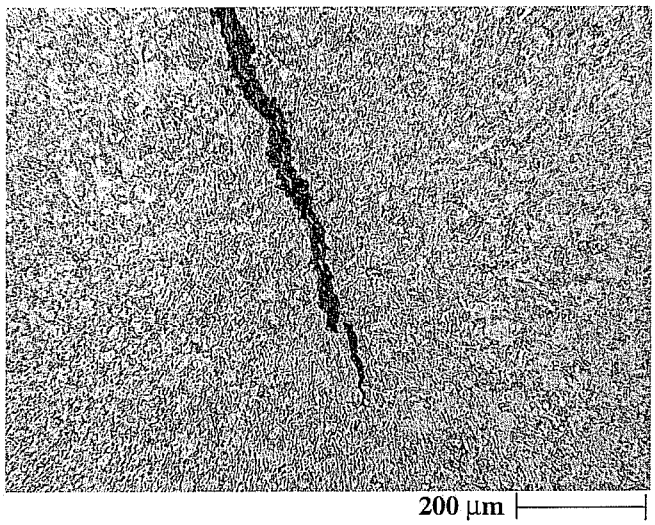
Figure 7. Case Two: Documenting The Microstructural Appearance Of The Circumferential Cracking Initiating In The T91 HAZ At The OD Surface. Note That The Crack Had Propagated Through The Coarse-Grained HAZ Of The T91 Tubing Adjacent To A Visible Decarburized Zone In The B-3 Weld Deposit. Note: The Absence Of Creep Damage.



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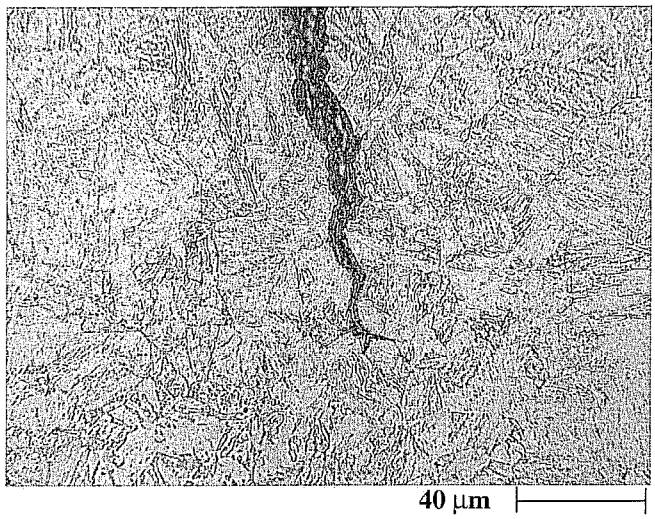

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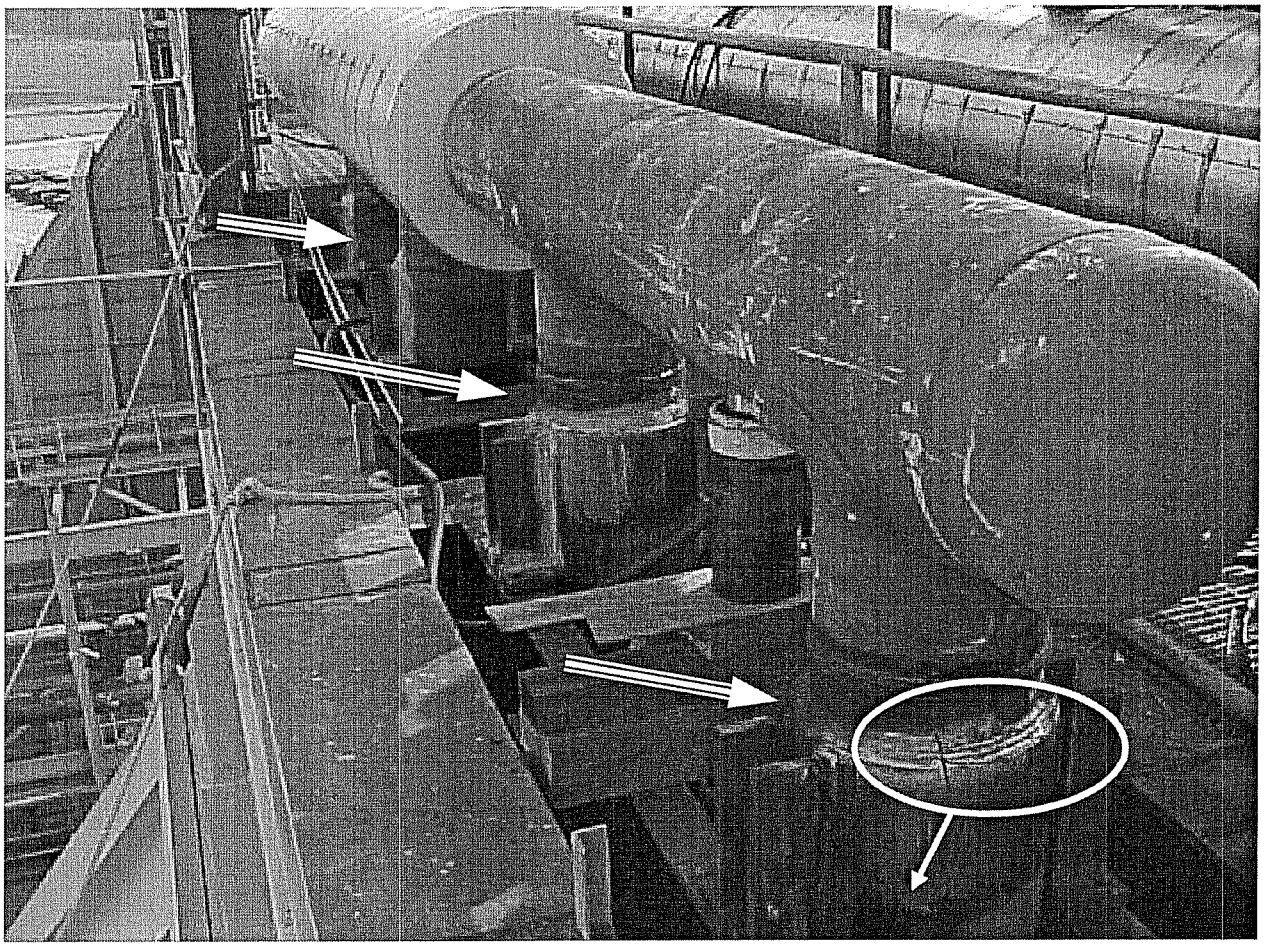
Figure 8. Case Two: Documenting The Appearance Of The Crack Tip At One Of The Intergranular HAZ Cracks Shown In Figure 5. Slight Propagation Has Occurred In Service At The Tip Of The Intergranular Crack. Note The Absence Of Creep Damage.



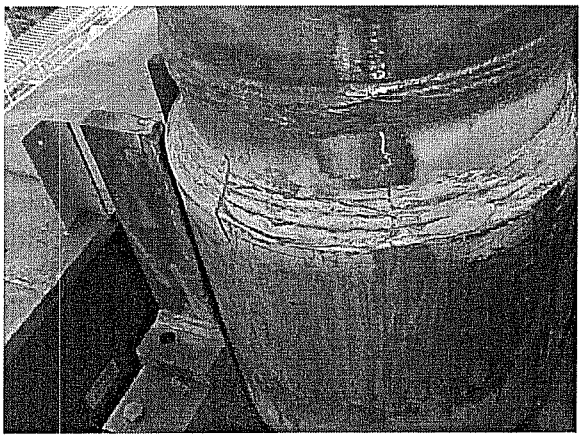
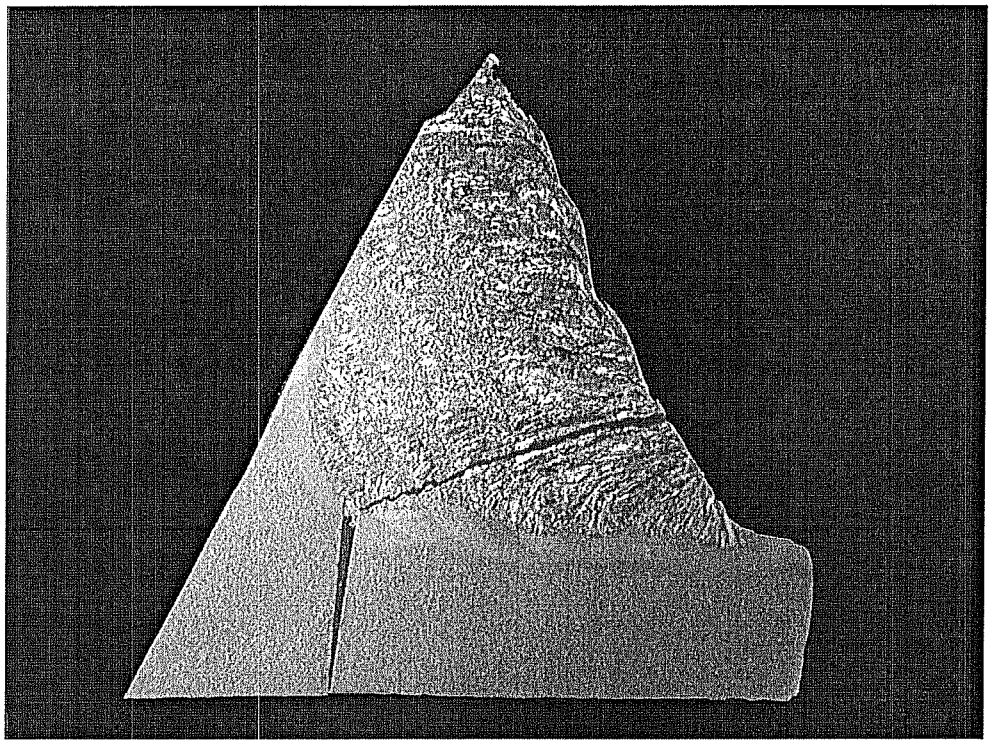


Figure 9. Case Three: Documenting The Appearance Of The SH Outlet Header And The Outlet Steam Links Discussed As Case Three. The White Arrows Indicate The Cracked Fillet Welds, One Of Which Is Shown In The Inset.



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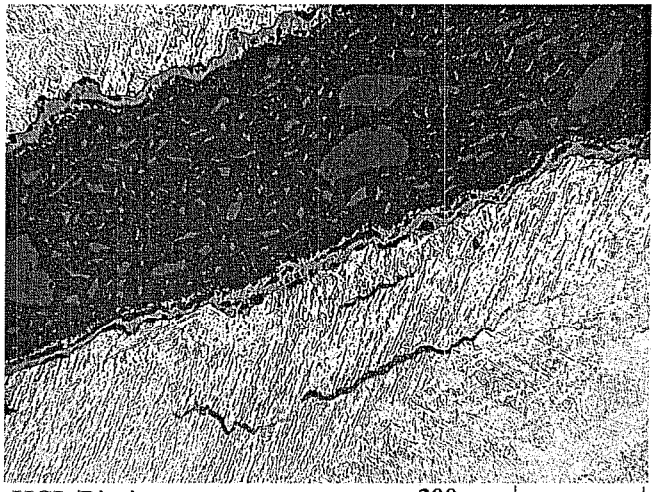
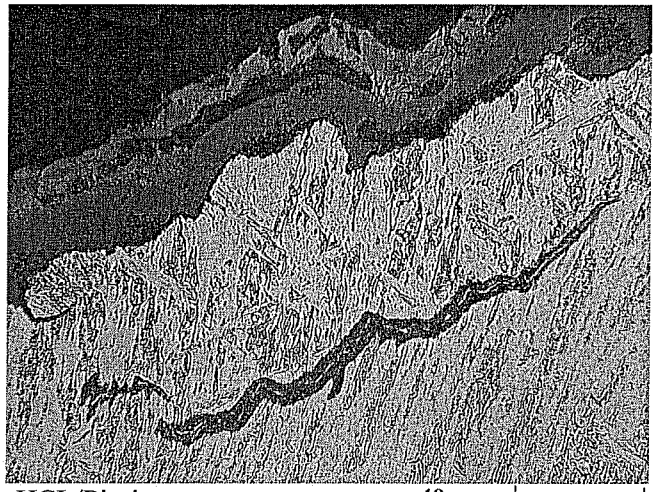


HCL/Picric 200 μm



HCL/Picric 40 μm

Figure 10. Case Three: Documenting A Transverse Cross-Section Of The Cracking In One Of The Fillet Welds.

SESSION 3: Mechanisms #1 – Corrosion Fatigue

Chairman: R. Coutant, Progress Energy

Corrosion Fatigue – American Electric Power Company Big Sandy Plant Experience

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Introduction

Corrosion fatigue in boiler tubes has been a major source of availability loss in fossil-fueled power plants for more than ten years.[1] The Electric Power Research Institute (EPRI) has reported that corrosion fatigue has recently become the number one water chemistry related tube failure in the utility industry.[2]

Historically, on the American Electric Power Company (AEP) coal fired fleet, water chemistry related boiler tube failures accounted for approximately 20% of all boiler tube failures. In 2002, AEP management challenged the chemical staff by setting a corporate goal of zero water chemistry related tube failures by the end of 2006. A program was set in motion to achieve this corporate goal. The program included a quarterly benchmarking based on 12 world-class characteristics defined by the AEP chemist (see Figure 1), equipment and instrumentation upgrades, development of unit specific chemical operating guidelines with chemical troubleshooting charts to replace the existing corporate chemical operating specifications, and additional training for plant personnel in boiler tube failure mechanisms.

Since the start of this world-class cycle water chemistry initiative, AEP has seen the number of water chemistry influenced boiler tube failures decrease. With this said, corrosion fatigue is the number one water chemistry influenced boiler tube failure for the AEP system. American Electric Power engineering believes that the water chemistry influenced boiler tube failure mechanisms on the AEP fleet are being addressed and controlled, except for the corrosion fatigue mechanism.

Figure 1
AEP World Class Characteristics

1. Operate safely within designated parameters 100% of the time
2. Proactive/Preventative approach
3. Understanding and attention of chemical impacts all through the organization for all equipment
4. Integrated water chemistry business plan
5. Identify performance gaps and develop plan to close those gaps

6. Continuous benchmarking/learning/raising the bar
7. No boiler tube failure or turbine problems from cycle chemistry
8. Challenge the status quo
9. Zero cycle chemistry equipment failures due to cycle chemistry [turbines, condensers, feed water heaters, etc]
10. Complete organizational alignment on goals, parameters, and action points
11. All employees take ownership in dependencies developed for their positions
12. Employees are knowledgeable of water chemistry issues and take appropriate actions

Background

Big Sandy (Kentucky Power Company) Unit 1 is a 2400 psig; base loaded coal-fired B&W sub-critical drum boiler with natural circulation that went into service in 1962. It has low NOx burners which are located on the front and rear walls. Historically, the unit has not had problems with corrosion fatigue tube failures (only four documented corrosion fatigue failures since 1985); although three incidents indicated that, the tube failure history may not reflect the condition of the boiler.

1999 In the main furnace ash hopper area, a furnace wall tube blew out a complete section of tube on the hot side. This failure caused the ash hopper area, from casing to outside of old gas fan duct work, to over-pressurize. This caused a six-inch steel beam to deform by approximately two-feet.

2000 In the main furnace ash hopper area, a furnace wall tube blew out a complete section of tube on the hot side. This caused the ash hopper to be over-pressurized. This release of steam caused the boiler seal skirt to be lost, causing steam to be released up the side of the boiler.

2001 In the boiler penthouse, several furnace wall tubes unzipped, releasing massive amounts of steam into the penthouse. This caused a 20 x 30 ft. rupture in the penthouse casing.

Then in 2002, burners were being modified with over-fire air ports. Because of this work, the plant decided to take advantage of the burners being removed to inspect the furnace walls using a boroscope. This inspection was very disturbing. Before we review the results of the inspection, lets first review some historical data that can contribute to the initiation and propagation of corrosion fatigue failures: Boiler water chemistry, chemical cleaning history, and number of startups.

Boiler Water Chemistry

Big Sandy Unit 1 has always operated under sodium phosphate treatment. Over the years, the control range has changed (see Figure 2).

Figure 2
Big Sandy Unit 1 Sodium Phosphate Control Range

Year	Boiler Water pH	Boiler Water PO_4 (ppm)
1962 – 1992	9.6 – 10.0	5 – 10
1993 – 1999	9.25 – 9.95	2 – 4
1999 – present	9.2 – 9.5	1 – 3

From initial startup of the unit in 1962 until 1990, makeup water to the unit was provided by an evaporator. In 1990, the Unit 1 evaporator was retired and makeup water for Unit 1 was provided from Unit 2. The water from Unit 2 was a combination of evaporator and demineralized water. At this time, typical makeup water conductivity to Unit 1 was between 3 and 5 mmho's. In 2003 a double pass reverse osmosis unit was installed to provide makeup water to Unit 1 and Unit 2. The Unit 2 evaporator was retired.

It should be noted that boiler water pH was not continuously monitored until 2003 with the installation of a continuous on-line pH meter. Prior to the installation of this meter, pH was manually checked daily.

This unit has had a history of underdeposit corrosion tube failures (both hydrogen damage and caustic gouging). Hydrogen damage failures were linked to high boiler water chlorides caused by evaporator upsets, and to a lesser extent, condenser leaks. Caustic gouging failures were due to operating with free hydroxide above two-ppm.

Chemical Cleaning History

Since 1970, Big Sandy Unit 1 has been chemical cleaned using tetrammonia EDTA. Prior to 1970, hydrochloric acid was used to chemical clean the unit. The history of Big Sandy Unit 1 chemical cleaning is shown in Figure 3.

Figure 3

Number of Hydrochloric Acid Chemical Cleanings	5
Number of EDTA Chemical Cleanings	11
Average Frequency of Chemical Cleaning	2.6 years

Startup History

Figure 4 shows the number of startups per year for Big Sandy Unit 1.

Figure 4
Big Sandy Unit 1 Startup History

Year	# of Startups	Year	# of Startups
1962	11	1983	25
1963	11	1984	13
1964	7	1985	22
1965	4	1986	19
1966	6	1987	18
1967	8	1988	10
1968	9	1989	11
1969	4	1990	20
1970	4	1991	13
1971	7	1992	10
1972	8	1993	9
1973	11	1994	8
1974	11	1995	11
1975	13	1996	7
1976	13	1997	8
1977	12	1998	11
1978	20	1999	9
1979	5	2000	11
1980	9	2001	8
1981	15	2002	13
1982	23	2003	12

Inspection Results

As stated earlier, the boiler furnace walls for Big Sandy Unit 1 were inspected in 2002 during the installation of over-fire air ports to reduce NOx. During this outage, Big Sandy used both UT and a conventional boroscope to identify corrosion fatigue sites. Using EPRI document TR-105261, which indicated typical locations for tube failures by corrosion fatigue, and Big Sandy's tube failure database, potential crack locations were determined for NDE.

The UT method was used in an attempt to locate corrosion fatigue sites on the hot side of the furnace wall tubes. Initially the sensitivity of the UT instrument had to be adjusted when tubes indicating corrosion fatigue sites using UT when removed indicated only pitting. After tuning, UT only found five tubes that had corrosion fatigue on the hot side of the tube.

At the same time UT was being used, a conventional boroscope was being lowered into furnace wall tubes. Using the conventional boroscope method, the plant was having trouble getting the camera past any bends (i.e. soot-blower openings), eventually breaking the camera. In areas where there were straight runs of tubes, this method was able to uncover several tubes with corrosion fatigue at lower windbox attachments on the cold side of the tube.

Discussions at this point with EPRI led the plant to use a fiber camera. EPRI recommended using a fiber camera because of its ability to traverse bends and still have a decent picture. Using this technique, corrosion fatigue sites were found at mostly all the lower windbox attachments scanned. All indications were axial cracks, with a family of cracks surrounding the cold side of the tube.

Although the fiber camera was not an exact method for locating corrosion fatigue sites, by watching the video of each tube scanned, priority tubes were removed and crack through wall length was determined. By gauging how many cracks and their perceived depth on the video of each tube, the plant was able to match what through wall would be expected and removed the worst affected tubes.

Because of this success it was decided to cut out hand hole caps on the waterwall headers at the penthouse and using the fiber camera inspect additional side wall tubes.

The use of the fiber camera was successful in locating corrosion fatigue sites. Because of this inspection, sixty tubes were replaced that had corrosion fatigue cracking, ranging from 50% to 99% through wall damage. (Remember this is on a unit that has only experienced four tube failures since 1985 attributed to corrosion fatigue!)

Corrosion Fatigue – Where Are We Now and What is Needed?

Corrosion fatigue is caused by the synergistic effects of stress and environment. This leads to a breakdown of the protective magnetite on a tube surface by both mechanical (stress) and chemical (environment) means.[1] Corrosion fatigue is a discontinuous process with cracks initiating and growing during transient periods such as starts and stops, and full load operation.[1] Boiler water chemistry (low pH and high dissolved oxygen) plays a role in the initiation and propagation of corrosion fatigue cracks. With this said, it is important to understand that stress is the main driver for corrosion fatigue initiation and propagation. Even with perfect water chemistry, corrosion fatigue initiation can occur. EPRI research has shown that the critical stress value to crack the protective magnetite layer and initiate corrosion fatigue is 0.1% strain.[3]

What was learned at Big Sandy Unit 1 is that a boiler can have serious corrosion fatigue damage throughout it without plant personnel realizing the magnitude of the damage. Considering that EPRI has stated that corrosion fatigue is now the number one water chemistry related tube failure in the industry, it makes you wonder how many sub-critical boilers in the industry are in the same condition as Big Sandy.

To properly address the corrosion fatigue risk for the utility industry, American Electric Power believes further research is needed.

The utility industry needs an inexpensive NDE technique that can locate corrosion fatigue sites on both the hot side and cold side of a boiler tube, inspecting only from the hot side of the tube. This NDE technique would need to be able to quantify the crack length and depth.

A technique of detecting and sizing corrosion fatigue cracks on the cold side from the hot side has not been successfully demonstrated in the field. As corrosion fatigue has become the number one Boiler Tube Failure Mechanism for Big Sandy Unit 1, several different potential NDE techniques for corrosion fatigue indication have been evaluated over the years.

Initially in 2000 during a Unit 1 forced outage, an electromagnet acoustic transducer (EMAT) was used on Big Sandy Unit 1 lower furnace tubes at the ash hopper elbows and slope to sidewall connections. This technique detected hot side corrosion fatigue cracks but could not indicate cold side cracking. This technique was successful in a lab environment with fabricated flaws, but the nature of a true corrosion fatigue crack tends to mask itself from EMAT. In addition, the surface condition of the tube where the EMAT probe makes connects to the tube has to be semi smooth. Big Sandy Unit 1 tube condition has a lot of uneven grooves and pits from deslagging, typical of most units, which results in a poor surface condition. The EMAT NDE technique will indicate corrosion fatigue cracks on the hot side on a boiler tube with tube surface limitations but was not successful indicating cracks on the cold side of the tube.

During a routine maintenance outage, a full furnace scaffold was installed to facilitate installation of over fire air ports in 2002. An NDE technique using a UT transducer was tried because of previous success in finding hot side corrosion fatigue. It was hoped to transfer this technique to evaluate cold side corrosion fatigue cracking. The tube surface condition had to be sandblasted and very smooth for the technique to work on hot side crack detection let alone cold side detection. A UT transducer shoe assembly that introduced a controlled shear wave beam around the tube to produce a shear wave incident on a crack, thereby indicating crack size and depth. This technique was not successful in wrapping the beam around the tube to the cold side of the tube. Though it was successful finding hot side corrosion fatigue cracks, the sensitivity in sizing of correct depth was inaccurate. Several tubes were cut out that had minimal damage, in which this technique had indicated there were cracks 50% thru wall of the tube. This technique was not successful in finding cold side corrosion fatigue cracking and calibration was off in sizing of hot side corrosion fatigue cracking.

During a routing maintenance outage in 2004, the plant tried to x-ray tubes at the lower wind box attachment to indicate cold side corrosion fatigue cracking. They had hoped to use a low source technique in which they could view thru a buck stay to indicated cracks on the cold side of the tube from the cold side. This was a complete failure as the technique was not able to get past the buck stay.

Moving forward, several vendors have used Big Sandy Unit 1 boiler tube samples of corrosion fatigue that were removed from video probe inspections to try their new techniques in the lab environment. The video probe has been the most successful technique AEP has found to indicate cold side corrosion fatigue cracking. Unfortunately, this technique's flexibility is limited to tube length and size along with header access. In addition, crack size and depth is not measurable, just intuitive. To date no vendors have been successful in transferring a cold side corrosion fatigue cracking NDE technique from the lab to actual plant environments.

Concurrent to the above-mentioned research, American Electric Power also believes that research is needed to further the understanding of the corrosion fatigue mechanism. This research should include:

1. The latest overall approach to corrosion fatigue was published in the fifth EPRI Corrosion Fatigue report based on extensive monitoring (chemistry, strain and temperature) that was conducted in Australia.[4] Although this approach was consolidated and confirmed in the Corrosion Fatigue: State of Knowledge (SOK)[3] report written after the fifth report and the Boiler Tube Failure Book,[1] this approach has never been applied again. It is time to apply this research.
2. It is imperative in any corrosion fatigue investigation that the temperature/strain is monitored in parallel with the boiler water chemistry. In this way the relationship between the time when the peak strain is imposed on the internal surface of the tube can be compared to the time when the chemistry is out of specification. This should be the basic premise behind further research.
3. A criteria for how long it will take before a crack will fail is needed. A ranking system possibly based on size of crack, depth of crack, location of crack etc. is needed so decisions regarding where to replace damaged material first can occur.
4. The impact of operational parameters (in particular, ramp rates during startup shutdown and load changes and sliding pressure) on corrosion fatigue crack growth rates needs to be developed. Methods to determine the operational changes that can be followed to slow down the corrosion fatigue crack growth rate is needed.
5. An evaluation on the benefits of material changes to reduce the risk of corrosion fatigue is needed.

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Research and Service Experience with Environmentally Assisted Cracking of Low Alloy Steel

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ABSTRACT

Environmentally assisted cracking (EAC) of carbon and low-alloy steels has been identified as a possible degradation mechanism for pressure vessel and piping in nuclear power plants. Selected aspects of research and service experience with cracking of these materials in high-temperature water are reviewed, with special emphasis on the primary pressure boundary in boiling water reactors. The main factors controlling EAC susceptibility under reactor conditions are discussed with regard to both crack initiation and crack growth. The adequacy and conservatism of the relevant engineering criteria for component design and disposition of detected or postulated flaws are evaluated in the context of recent research results, e.g., on the effect of so-called "ripple loading", or of water chemistry transients. Finally, the relevant operating experience over the last 30 years is briefly summarized and compared with the background knowledge which has been accumulated in more recent laboratory experiments. Some of the insights gained in this work may also be of value in improving understanding and prediction of the EAC behavior of carbon and low-alloy steels in certain fossil plant components, if appropriate allowances are made for differences in temperature and water chemistry.

INTRODUCTION

Carbon and low-alloy steels (C&LAS) are widely used for pressure-boundary components such as tubing, piping and pressure vessels in both fossil and nuclear power plants (NPP).[1,2] Along with other aging mechanisms such as mechanical fatigue, erosion corrosion and (for NPP) irradiation embrittlement, environmentally assisted cracking (EAC) is a possible degradation process for C&LAS components. EAC is used here as a general term to cover the full spectrum of corrosion cracking ranging from stress corrosion cracking (SCC) to corrosion fatigue (CF)[3]. Differentiation of mechanisms is usually performed according to the type of mechanical loading involved (see Table 1) and strain-induced corrosion cracking (SICC), which involves slow, dynamic straining with localized plastic deformation of material, but where obvious cyclic loading is either absent, or is restricted to a limited number of infrequent events such plant start-up and shut-down, is increasingly used as an appropriate term to describe the area of overlap between SCC and CF.[4]

Low-cycle CF and SICC in de-aerators, feedwater piping and tanks, boiler tubes, etc. continue to be the damage mechanisms responsible for the largest percentage of availability loss in fossil power plants.[2,5,6] Although CF and SICC are less significant in NPP, they have occurred[7] and are perceived to be damage mechanisms which need to be considered for older plants, especially those considering lifetime extension. Because of the safety implications of EAC in a nuclear context, most of the research described here

originates from studies involving LAS in boiling water reactor (BWR) environments,[8] which are characterized by a neutral pH, very high levels of water purity (conductivity is typically ~0.1 μS/cm), and varying contents of dissolved oxygen and hydrogen (both from radiolysis in the reactor core and, increasingly, from the deliberate addition of hydrogen gas in order to lower the electrochemical corrosion potential (ECP) of structural materials). Potentially, however, much of the knowledge gained in this context has wider implications, e.g. for the service behavior of similar materials in conventional power stations, particularly those using oxygenated water treatment.[9]

EXPERIMENTAL BACKGROUND KNOWLEDGE

Main Factors of Influence for EAC

EAC initiation and growth in LAS are governed by a complex interaction of environmental, material and loading parameters and most influencing factors are interrelated and synergistic.[10] The major parameters of influence on EAC in C&LAS in neutral, high-temperature (HT) water are summarized in Table 2 and discussed briefly in the remainder of this section.

Susceptibility Conditions for EAC Initiation

SCC

Table 3 shows an early assessment scheme, based on both laboratory and field experience, for SCC initiation (susceptibility) and crack growth in LAS at normal strength levels (yield stress < 600 MPa) under BWR normal water chemistry (NWC) conditions according to Hickling.[11] SCC initiation from smooth, defect-free surfaces under static load is generally only observed for stresses at the water-wetted surface above the high-temperature yield stress, quasi-stagnant flow conditions, and increased concentration levels of anionic impurities such as SO_4^{2-} or Cl^-. Furthermore, if complete exhaustion of low-temperature creep was allowed to occur before the specimens were exposed to high-purity, HT water, no SCC was observed, thus indicating "non-classical" SCC behavior and confirming the importance of dynamic straining for EAC of LAS under such conditions. Based on experimental evidence, SCC initiation during stationary, transient-free BWR/NWC power operation from defect-free surfaces therefore appears to be extremely unlikely,[12] but growth of a pre-existing crack could occur under certain conditions, as discussed later.

SICC and CF.

Slow strain rate (SSRT) and low-cycle fatigue (LCF) tests with smooth specimens have clearly shown that EAC can occur in LAS (yield stress of 300 to 600 MPa) in oxygenated, high-purity HT water (κ < 0.3 μS/cm), if the following conditions are simultaneously attained over a sufficient period of time:

- Water temperature > ~150 °C. Although susceptibility then increases with temperature up to ~290 °C (usual BWR reactor conditions), a maximum in cracking susceptibility is sometimes observed at intermediate values.
- Corrosion potential > ECP_{crit} = ~-200 mV_{SHE}. Depending on flow rate and temperature, a dissolved oxygen (DO) content of 20 to 100 ppb is sufficient to exceed this threshold. EAC susceptibility then generally increases with increasing ECP (or DO).

- Loading which leads to (local) macroscopic strains above the elastic limit, with susceptibility increasing strongly with the degree of plastic strain.
- Positive strain rates below ~10^{-3} s^{-1}. EAC susceptibility then tends to rise with decreasing strain rate, but saturation of this effect is often observed at much lower rates.
- EAC susceptibility increases with increasing steel sulfur content and a lower threshold is often quoted at ~ 0.003 wt.%, but the experimental evidence for the latter is weak. Furthermore, a distinct material susceptibility to dynamic strain aging (DSA), or a low yield stress, may favor crack initiation by SICC.

If one of these conjoint threshold conditions is not satisfied, SICC initiation is extremely unlikely and no, or only minor, environmental reduction of fatigue life is observed in HT water. Furthermore, in high-purity water, a high flow rate may completely suppress SICC susceptibility and significantly retard fatigue crack initiation (in particular for low strains) compared to quasi-stagnant conditions, since the risk for formation of aggressive, occluded water chemistry within small surface defects is significantly reduced by convection. Incipient EAC cracks in LAS often originate from corrosion pits (see Fig. 1) and the question of whether or not they will subsequently grow may well be related more to the specific (electro)chemical "micro-environment" within such pits (in particular, to the existence of ongoing metal dissolution), rather than to the cyclic loading. Bulk water conductivity (or specific anionic impurities like Cl^- or SO_4^{2-}) also has a strong effect on CF life (see Fig. 2a)[13] and limited testing using step changes in environmental conditions indicates that even a few cycles under aggressive water chemistry may have a disproportionately strong effect on reducing resistance to cracking (see Fig. 2b)[14].

Design against fatigue cracking usually relies on the use of fatigue curves and endurance limits (derived mainly from small specimen tests) which do not explicitly consider the corrosive effect of specific environments, although the degree of included conservatism may often offset this factor to a large extent. Numerous laboratory data obtained under quasi-stagnant conditions suggest, however, that the factors of 2 on cyclic stress amplitude or 20 on cycles to failure included in the ASME Section III Code may not always be sufficient to cover the effect of a simulated BWR/NWC environment.[15] Fig. 3 shows an example of the effect of oxygenated HT water on fatigue behavior for both C & LAS from the recent work of Chopra and Shack.[16] It is also notable here that increased surface roughness has a pronounced negative effect (factor of ~3) on the fatigue life in a HT air environment, but very little or no effect on the results of testing in aqueous media.

For NPP components, there has been an ongoing debate for many years as to whether the relevant ASME Section III curves should either be redrawn to account for the effects of reactor water[17], or whether so called "environmental factors" (F_{en}) should be used during calculations to ensure long-term component integrity.[18] In Japan, the latter approach has already been adopted, but there are major differences of opinion internationally, both on the necessity of such procedures and the key question of the thresholds to be used for inclusion of environmental effects (see Table 4 from a recent publication by Higuchi).[19]

Interestingly, the German TRD 301 code for conventional steam boilers has attempted for many years to limit the amount of plastic strain which may be reached in a structure so as to avoid corrosion fatigue damage. The mechanistic justification for this was provided over 30 years ago by Lehr[20], who demonstrated that strains of above 0.1 to 0.2 % are necessary to impair the protective nature of magnetite films at an unflawed, LAS surface. Such thinking may be helpful in terms of overall component design, but it tends to ignore the fact that damage due to EAC is usually highly localized in nature. Real structures usually contain a multitude of flaws and surface imperfections that can easily result in much higher local strains than are indicated by more global stress/strain calculations.

In engineering terms, freedom from cracking in power plant components often means the absence of flaws which have to be to be registered as indications during non-destructive examination. In terms of fatigue in structural materials, this usually relates to cracks which are - in mechanistic terms - already quite large (e.g., at least 5 mm long and 2 mm deep). Such dimensions also correspond to the size of crack typically designated as "initiation" in (corrosion) fatigue testing on the basis of detection of a 25% load drop during cycling. In fact, however, attainment of such a crack size already involves mainly crack growth and careful replication work by Solomon et al.[21] showed that genuine initiation (corresponding to a load drop of ≤1% in CF testing) relates to the formation of individual cracks which are at least one order of magnitude smaller. Under benign environmental conditions, these cracks may fail to grow at all during further cycling. Such "short crack" behavior has been insufficiently studied under EAC conditions.[4,16]

Susceptibility Conditions for Crack Growth through EAC

The range of system conditions where growth of pre-existing cracks through EAC may occur is significantly extended compared to the initiation susceptibility conditions described above. E.g., CF crack growth of LAS has been observed in PWR water free from contaminants at low ECP (below -500 mV_{SHE}) under certain cyclic loading conditions, and also in BWR environments at temperatures below 150 °C.

SCC

Notwithstanding the relative absence of SCC incidents in nuclear RPV and piping steels in the field, this has been observed in laboratory tests under simulated BWR conditions with CGRs ranging from 30 μm/year to 3 m/year under nominally similar testing conditions. The SCC behavior of LAS in oxygenated, HT water and its relevance to BWR power operation has therefore been a subject of controversial discussions for many years. Careful re-analysis of older data together with recently performed, well-controlled experiments[22,23,24,25] have shown very low susceptibility to SCC crack growth under static loading conditions in oxygenated HT water (simulated BWR NWC environment) at temperatures around 288 °C. Fast and sustained SCC crack growth was only observed with high anionic impurity levels in the bulk water (significantly exceeding action level 1 in the EPRI BWR water chemistry guidelines[8] – see Table 5) or in "overloaded" specimens (stressed either near to the critical fracture toughness value K_{IJ} for the onset of ductile crack growth, or already exhibiting gross ligament yielding).

Based on the results of these tests and other well-qualified data for simulated BWR environments, disposition lines for SCC crack growth in LAS during BWR power operation[26] were proposed by an international group of experts, working within the framework of the EPRI BWRVIP Project, and accepted by the US Nuclear Regulatory Commission (NRC) as an interim position. Disposition line 1 in Fig. 4 applies to crack growth in LAS under static loading and transient-free, stationary BWR power operation conditions. Disposition line 2, on the other hand, may be used for estimating SCC crack growth both during, and 100 h after, significant transients in water chemistry (> action level limit 1 in Table 5), or for minor load transients not covered by fatigue evaluation procedures.

The conservative character of the first disposition line for SCC crack growth in LAS has been confirmed by several independent studies, but recent results[27,28,29] have revealed that disposition line 2 may be significantly exceeded for the case of small load fluctuations at high load ratios (so-called "ripple loading" with R values > 0.95) or with chloride transients above action level limit 1, even at fairly low stress intensity values (see Fig. 5 and 6). After such a transient, sustained SCC with a CGR above line 2 was also observed in a preliminary test for a significantly longer time interval than 100 h. On the other hand, line 2 seemed to conservatively cover even very severe sulfate transients in the range up to or slightly above EPRI BWR action level limit 3 values.

Laboratory testing has thus shown that sustained and fast SCC can only occur under the following, very specific conditions, which appear atypical for current BWR power operation practice with modern LAS components:

- A high corrosion potential ECP > +100 mV_{SHE} / high DO (>> 200 ppb) and quasi-stagnant flow conditions.
- Chloride-content ≥ "EPRI action level limit 1", sulphate-content > "EPRI action level limit 3".
- A high steel sulfur-content (> 0.020 wt.% S), in particular in combination with S-segregation zones.
- Intermediate temperatures (180 – 270 °C) in connection with distinct DSA susceptibility (see Fig. 7).
- A high hardness/yield stress level (> 350 HV_5, Rp > 800 MPa), e.g. in inappropriate weld HAZs.
- Loading close to K_{IJ}, or severe violation of small-scale-yielding conditions.
- Ripple loading, or relatively frequent periodical partial unloading.

SICC and CF.

For nuclear plants, the ASME BPV Code, Section XI, Appendix A, Article A-4300 contains a set of reference fatigue CGR ($\Delta a/\Delta N$) curves for carbon and LAS in air ("air" curves) or in reactor coolant environment ("wet" curves). The current ASME XI wet curves (Fig. 8) are based on lab data obtained prior to 1980. They depend explicitly on ΔK and R, but not on other variables that are known to be important, such as loading

frequency, ECP/DO, or steel sulfur content. System conditions (or thresholds) where environmental effects on fatigue crack growth can be neglected (or excluded) are not, at present, defined in the ASME Section XI code. The same curves are used for different types of carbon and LAS and for BWR/NWC, BWR/HWC/NMCA and PWR primary or secondary side conditions, although a recent code case (N-643) provides, as an alternative, more specific lines for PWR primary water (also shown in Fig. 8). These take into account the interaction between steel sulfur content and CF for this environment and also introduce the important concept of defining load rise times. Efforts are currently ongoing to develop and propose a similar Code Case for BWR environments.[30]

Based on statistical analysis of the extensive laboratory data (for air, PWR and BWR conditions) obtained since 1980, a proposal for new reference crack growth curves was made by Eason et al.[31,32], taking into account the strong effect of strain rate/loading frequency on CF crack growth in water environments. This approach has not (yet?) found acceptance, however, primarily because of the difficult of defining appropriate ramp times and the complications involved in including these in component analyses. Work is ongoing at EPRI in an attempt to resolve this issue.[33]

The adequacy of the current ASME XI wet reference fatigue CGR curves under PWR and BWR conditions has been evaluated for most combinations of loading, environmental and material parameters in several different laboratory investigations and the results have been recently summarized in a comprehensive manner by Seifert and Ritter.[34] Some examples of relevant comparisons are given in Fig. 9 and 10.

In summary, the current "ASME XI wet reference fatigue CGR curves" conservatively cover the CF CGR lab data under most combinations of loading, environmental and material parameters and have usually only been exceeded under some very specific, simulated BWR plant conditions. They might therefore be regarded as an adequate, general bounding curve, but they do not realistically describe and reflect the experimentally observed CF crack growth behaviour of LAS in oxygenated HT water. The curves either predict CGRs which are clearly too high (e.g., for $\nu \leq 10^{-2}$ Hz and ECP < -200 mV_{SHE} or for 10^{-1} Hz $< \nu <$ 10 Hz and high ΔK) or too low (e.g., for $\nu \leq 10^{-2}$ Hz and ECP > 0 mV_{SHE} or for 10^{-2} Hz $< \nu <$ 10 Hz and high R/small ΔK).[34] Furthermore, system conditions or thresholds (e.g., $\nu > 10$ Hz), where environmental effects on fatigue crack growth can be neglected or excluded, are not defined in ASME XI. Any procedure which adequately considers the strong effect of loading frequency (and of ECP) would have the potential to reduce both uncertainty and undue conservatism, but would also result in more complicated flaw tolerance evaluations than those performed to date, since - as mentioned above - the loading frequency/strain rate of different transients would have to be considered in an appropriate way.

NUCLEAR POWER PLANT OPERATING EXPERIENCE

The accumulated operating experience and performance of carbon and low-alloy primary pressure-boundary components in NPP is very good worldwide. Use of the current fatigue design and evaluation codes (ASME III and XI) has been generally successful in

preventing fatigue cracks and failures in LAS components and therefore the limited and non-specific consideration of EAC in these codes would - at first sight - seem to be adequate, or even (fortuitously) conservative, under most operating circumstances. However, instances of EAC have occurred (particularly in BWR service), most often in LAS piping and, more rarely, in the RPV (where most locations are normally isolated from contact with the environment by a stainless steel weld overlay cladding).[4,5,7,35] Oxidizing agents, usually dissolved oxygen, but sometimes dissolved cations such as Cu^{2+}, and relevant dynamic straining were always involved in these field incidents which, were attributed either to SICC or to CF (cf. Table 1). Cracking incidents with a major, or relevant, contribution of SCC, even to crack propagation, in properly manufactured and heat-treated low-alloy primary pressure-boundary components are not known to the authors. In fact, long-term exposure and re-inspection of unclad components, such as BWR feedwater nozzle radii or vessel heads, confirms the generally excellent resistance of LAS to SCC in reactor coolant

The following carbon and low-alloy LWR pressure-boundary components have been affected:

- Steam and feedwater piping and condensate systems of BWRs (mostly horizontal systems with stagnant or low flow and/or condensing steam or auxiliary condensates, intermittently-operated systems (flushing lines), particularly at pipe to elbow joints and pipe bends, although isolated cases are known in straight sections of piping at mechanical restraints. (Primarily SICC).
- Feedwater nozzles of BWR reactor pressure vessels. (Crack propagation through low-cycle CF, following initiation in SS cladding from high-cycle thermal fatigue).
- Feedwater piping/tanks and heat exchangers in the secondary circuit of PWRs, feedwater nozzles of PWR steam generators, steam generator girth welds. (Various EAC mechanisms).

These cracking incidents involving an environmental component have been clearly associated with some combination of the following aspects:

- **Slow dynamic straining**, due to global and local thermal stratification/striping (e.g., during hot-stand-by at low feedwater flow rate), or due to thermal and pressurisation cycles (e.g., plant-start-up/shut-down, hot stand-by, turbine rolls, etc.).
- **An oxidizing environment**, normally due to oxygen (in some few cases Cu^{2+} cations from brass condensers helped to raise the ECP) and sometimes in conjunction with unspecified anionic impurities (Cl^-, SO_4^{2-}, etc.). Most PWR cracking incidents involved SG feedwater under specified operating conditions, or at specific locations, where the normally low contents of oxygen cannot be assumed. The fact that cracking frequently occurred in BWR lines with stagnant steam or non-degassed condensate, but not in comparable lines carrying flowing steam, is another indication that high oxygen concentrations (and therefore corrosion potentials) are crucial parameters with respect to the occurrence of EAC, since such conditions are known to encourage the formation of a condensate film rich in dissolved oxygen.
- **High local stresses** (around or above the HT yield point, including high secondary/residual stresses), due, for instance, to local stress raisers, geometrical

welding defects (misalignment of weld edges, excessive weld penetration leading to root notches and lack of fusion, or incipient cracking in the root region), pipe bends in conjunction with inadequate pipe supports or restraints, overly localized post-weld heat treatment and/or fit-up deformation.

EAC damage was usually detected by non-destructive examination and seldom led to through-wall penetrations with leakage. In several of the reported incidents, EAC in LAS occurred as a result of substantial departures from either design intentions or normal operation practice. Such cases are identifiable and can therefore be avoided. However several incidents were related to unanticipated (and therefore) unevaluated loading sources (particularly the frequency and/or severity of thermal stress cycles in critical locations), thus indicating design inadequacies.

Cracks often initiated from water-wetted geometric discontinuities (which result in local stress concentrations) and/or in regions, where the formation of an aggressive, occluded water chemistry was favored (stagnant flow, crevices, etc.). In many cases, EAC cracks preferentially initiated from corrosion pits and corrosion during shut-down periods (pitting, corrosion products (rust) close to the water line as a possible source of anionic impurities during start-up) was sometimes a further contributing factor.[4] In general, however, crack initiation has more often been caused by high-cycle fatigue due to local thermal stratification or thermal striping loads, which are limited to near-surface regions. Crack propagation was then usually dominated by low-cycle fatigue from slower and less frequent transients, due, e.g., to global thermal stratification or operational power transients (start-up/shut-down, hot stand-by, etc.). A complete root cause evaluation has not always been performed in all cracking incidents. Therefore, identification of the cracking mechanism has not always been completely succesful and, in particular, assessment of the relative contributions of EAC and pure mechanical fatigue to the total crack advance has often not been possible.

SUMMARY AND CONCLUSIONS

The accumulated operating experience and performance of carbon and low-alloy primary pressure-boundary components in NPP is very good worldwide. However, isolated instances of EAC have occurred, particularly in BWR service, most often in LAS piping and, very rarely, in the RPV itself. Oxidizing agents, usually dissolved oxygen, and relevant dynamic straining were always involved. These cases were attributed either to SICC or CF, with - at the most - only minor contributions from SCC. There is a good correlation between operating experience and experimental/mechanistic background knowledge on EAC and pitting behavior in the system LAS/HT water. Both aspects confirm the high resistance of LAS to SCC under steady-state power operation and static loading conditions and clearly reveal that slow, positive (tensile) dynamic straining, with associated localized plastic yielding of the material, and sufficiently oxidizing conditions are essential for EAC initiation and crack growth in LWR environments subject to good water chemistry.

Although the relevant ASME Section III fatigue design curves would appear to be adequate in most cases, more specific treatment of EAC effects is under consideration. If adopted, this will cover both a potential elimination of margins in the low-cycle region for LAS exposed to certain environments and permit a better representation of expected material behavior (thus removing the need for unduly conservative assumptions) in the context of component fatigue re-calculations for plant life extension.

The current ASME Section XI "wet" reference curves may be regarded as an adequate, general bounding curve for CF crack growth under most LWR operating conditions. However, they do not realistically describe and reflect the experimentally observed CF crack growth behaviour of LAS in oxygenated HT water. Depending on loading frequency and ECP, they predict CGRs which are either too high or too low. Thus, there is potential for further optimizing the EAC crack growth evaluation procedures in ASME XI, particularly by a more realistic description of the CF behaviour under BWR conditions. This may best be achieved by the introduction of a specific code case, including thresholds for accelerated crack growth, analogous to the N-643 procedure now in place for PWR primary water. Such developments have the potential to reduce both residual uncertainty (in those relatively infrequent and specific cases where the current curves are not necessarily conservative) and undue conservatism (for most other cases).

In spite of the absence of SCC in the field, several unfavorable critical parameter combinations, which can lead to sustained, fast SCC with CGRs well above the relevant disposition lines, have been identified in recent laboratory experiments. Although most of them appear atypical for current BWR plant operation with properly manufactured, LAS components, further evaluation of their relevance appears warranted. In this context, particular attention should be paid to the effects of ripple loading, water chemistry transients involving chlorides and dynamic strain aging (at intermediate temperatures) on the SCC crack growth behaviour of C&LAS (including weld HAZ material).

The insights gained here in the field and in the laboratory over the last 30 years, and particularly more recently from systematic studies of LAS crack growth under static and cyclic loading in simulated NPP environments, may also be of value in improving understanding and prediction of the EAC behavior of C & LAS in certain fossil plant components, if appropriate allowances are made for differences in temperature and water chemistry.

TABLE 1: Basic types of environmentally assisted cracking (EAC) for C & LAS[3]

Mechanism	EAC SCC Stress corrosion cracking	SICC Strain-induced corrosion cracking	CF Corrosion fatigue
Type of loading	Static	Slow monotonically rising or very low-cycle	Cyclic: low-cycle, high-cycle
Operational relevance	Transient-free, steady-state power operation	Start-up/shut-down, thermal stratification	Thermal fatigue, thermal stratification, …
Characterization of crack initiation	?	Susceptibility thresholds: ECP_{crit}, $d\varepsilon/dt_{crit}$, ε_{crit}	ASME III F_{env}-approach
Characterization of crack growth	BWRVIP-60 SCC Lines	?	ASME XI Code Case N-643 (PWR)

TABLE 2: Major factors infuencing EAC of C&LAS in HT water[3]

Environmental Parameters	Material Parameters	Loading Parameters
- ECP and DO - Temperature - Cl^-, SO_4^{2-}, S^{2-}, HS^- - Flow rate	- S-content, morphology, size, spatial distribution and chemical composition of MnS - DSA, concentration of interstitial C and N - Hardness/yield stress if > 350 HV5/800 MPa	- Frequency, loading or strain rate - Level of load, K_I, stress, strain, ΔK - Type of loading - Residual stress

TABLE 3: Early assessment scheme for SCC susceptibility of C&LAS in BWRs[11]

Operating medium: high-temperature water or steam condensate with T > 170 °C						
O_2 [ppm]	Flow conditions	κ [µS/cm]	Crack initiation by SCC?	Deri-vation	Crack growth by SCC?	Deri-vation
< 0.2	typical for reactor	typical i.e. ≤ 0.1	no susceptibility	1	no susceptibility	1
< 0.2	quasi-stagnant	approx. 0.2	no susceptibility	1	no susceptibility	2
< 0.2	quasi-stagnant	Raised (e.g. by impurities)	x(for stress levels at the water-wetted surface in the region of the HT yield point)	2	possibility cannot be excluded, perhaps after incubation time	3
0.2 – 0.4	typical for reactor	typical, i.e. approx. 0.2	no susceptibility	1	no susceptibility	1
0.2 – 0.4	quasi-stagnant	approx. 0.2	x(for stress levels at the water-wetted surface > HT yield point)	2	possibility cannot be excluded, perhaps after incubation time	2
0.2 – 0.4	quasi-stagnant	raised (e.g. by impurities)	x(for stress levels at the water-wetted surface in the region of the HT yield point)	2	possibility cannot be excluded, perhaps after incubation time	2
>> 0.4	typical for reactor	typical, i.e. approx. 0.2	in general, no susceptibility (? at stress levels >> HT yield point)	1 3	susceptibility is suppressed through flow	2
>> 0.4	quasi-stagnant	< 1 (approx. 0.2)	x(for stress levels at the water-wetted surface ≥ HT yield point)	2	possibility cannot be excluded, perhaps after incubation time	2
>> 0.4	quasi-stagnant	raised (e.g. by impurities)	x(for stress levels at the water-wetted in the region of the HT yield point)	2	possibility cannot be excluded, perhaps after incubation time	2

x possibility cannot be excluded, perhaps after long incubation time

Derivation: 1: from experiments in more aggressive environments, 2: from appropriate autoclave experiments, 3: no direct experimental evidence

TABLE 4: F_{en} calculation models and thresholds, after Highuchi[19]

Japanese Latest Model (by Higuchi)	US ANL Model (by Chopra)
(Carbon & Low Alloy Steels) $\ln(F_{en})=-(0.199\ T^*\ O^* + 0.112)\ S^*\ \varepsilon'^*$ $\varepsilon'^*= 0$ ($\varepsilon' > 1.0\%/s$) $\varepsilon'^*= \ln(\varepsilon')$ ($1.0 \geq \varepsilon' \geq 0.0004\%/s$) $\varepsilon'^*=\ln(0.0004)$ ($\varepsilon'<0.0004\%/s$) $T^* =0.00531T - 0.7396$ ($T \geq 180°C$) $T^* =0.216$ ($T < 180°C$) $O^* =\ln(DO /0.03)$ ($0.03 \leq DO \leq 0.5$ ppm) $O^* =0$ ($DO < 0.03$ ppm) $O^* =\ln(0.5/0.03)$ ($DO < 0.5$ ppm) $S^* =17.23S+0.777$ $F_{en} = 1.0$ ($\varepsilon_a \leq 0.042\%$) ($\varepsilon_a$ of 0.042% is the same strain amplitude at 10^6 cycles in the design fatigue curve)	(Carbon Steel) : $\ln(F_{en}) = 0.554 - 0.101\ S^*T^*O^*\varepsilon'^*$ (Low Alloy Steel): $\ln(F_{en}) = 0.898 - 0.101\ S^*T^*O^*\varepsilon'^*$ $S^* = 0.015$ ($DO > 1.0$ ppm or $S > 0.015\%$) $S^* = S$ ($DO \leq 1.0$ ppm & $S \leq 0.015\ \%$) $T^* = 0$ ($T < 150°C$) $T^* = T\text{-}150$ ($150 \leq T \leq 350°C$) $O^* = 0$ ($DO < 0.04$ ppm) $O^* = \ln(DO/0.04)$ ($0.04 \leq DO \leq 0.5$ ppm) $O^* = \ln(12.5)$ ($DO > 0.5$ ppm) $\varepsilon'^* = 0$ ($\varepsilon' > 1\%/s$) $\varepsilon'^* = \ln(\varepsilon')$ ($0.001 \leq \varepsilon' \leq 1\%/s$) $\varepsilon'^* = \ln(0.001)$ ($\varepsilon' < 0.001\%/s$) $F_{en} = 1.0$ ($\varepsilon_a \leq 0.07\%$)

TABLE 5: Summary of action levels for reactor water during stationary BWR power operation from EPRI BWR water chemistry guidelines[8]

Control Parameter	Action Level 1	Action Level 2	Action Level 3
Conductivity [μS/cm]	> 0.3	> 1.0	> 5.0
Sulphate [ppb]	> 5	> 20	> 100
Chloride [ppb]	> 5	> 20	> 100

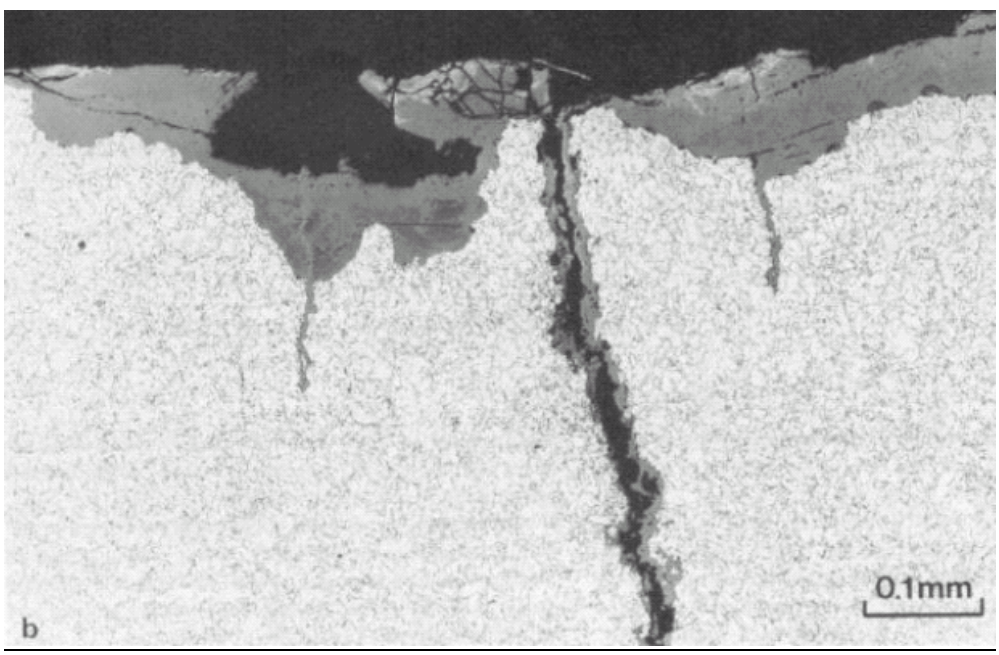

FIGURE 1: Incipient cracks originating from corrosion pits adjacent to a major SICC defect in a BWR pipe made of LAS (after Hickling & Blind[7])

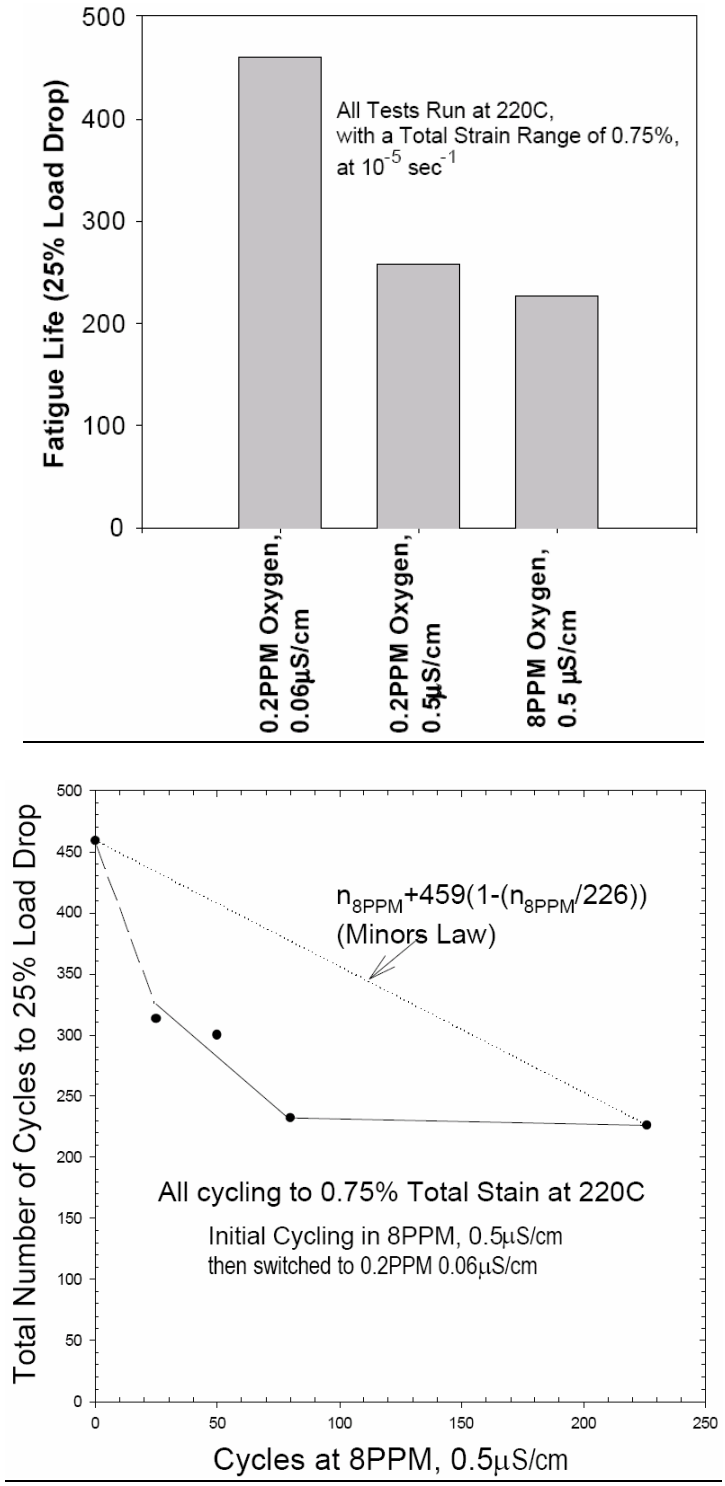

FIGURE 2: Work by Solomon[13,14] showing the importance of conductivity on the CF behavior of a LAS in oxygenated HT water:

a) Comparison of effects of oxygen and conductivity in normal fatigue tests
b) Disproportionate effect of initial cycling at high conductivity on fatigue life

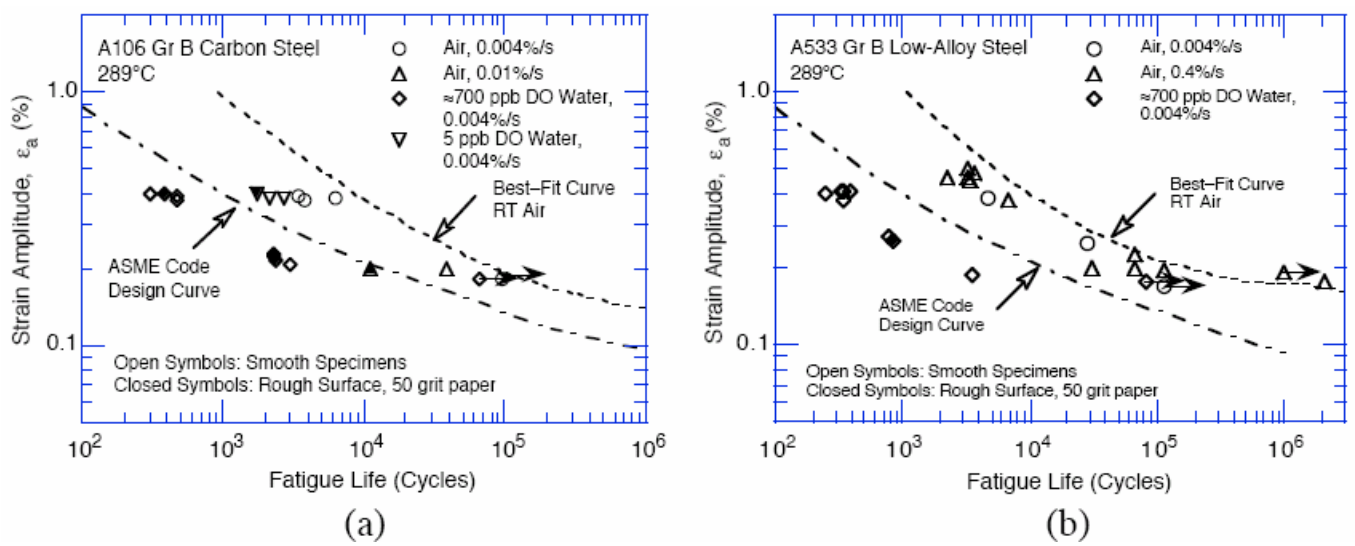

FIGURE 3: Effect of surface roughness on the fatigue life of (a) A106–Gr B carbon steel and (b) A533–Gr B low–alloy steel in air and high–purity water at 289°C [16]

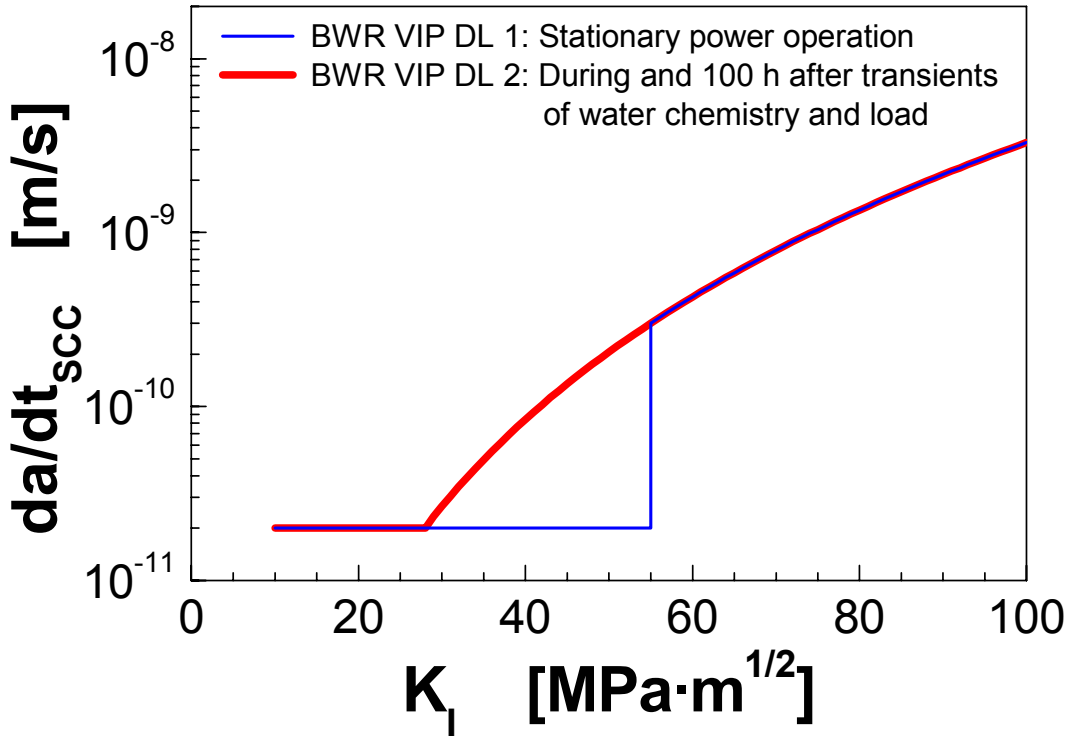

FIGURE 4 Disposition lines for LAS CGR under BWR/NWC conditions [26]

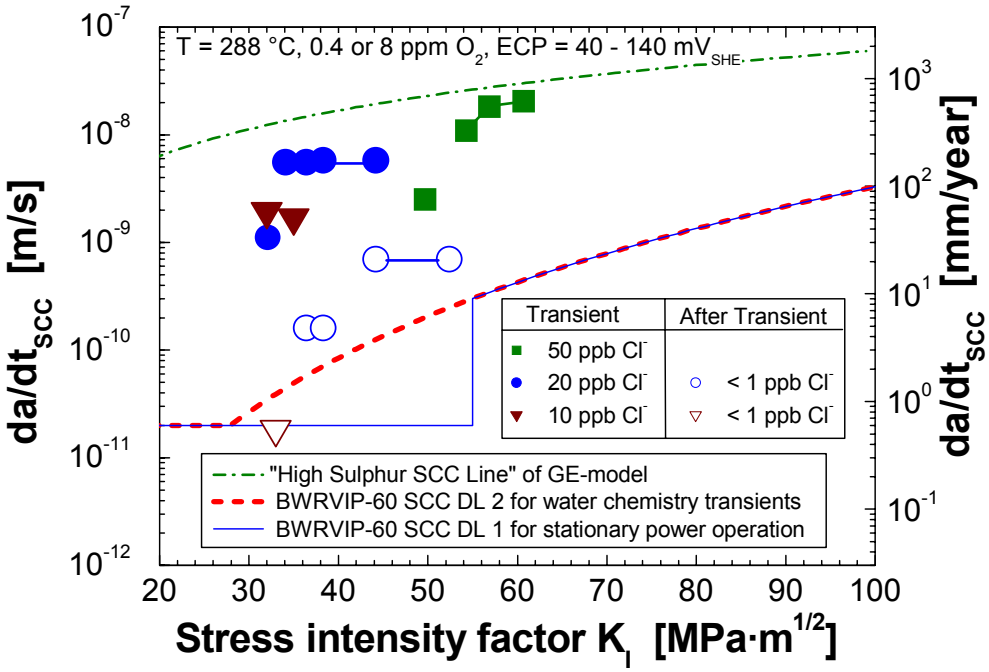

FIGURE 5: Effect of chloride transients on SCC CGR of different low-alloy RPV steels under BWR/NWC conditions [29]

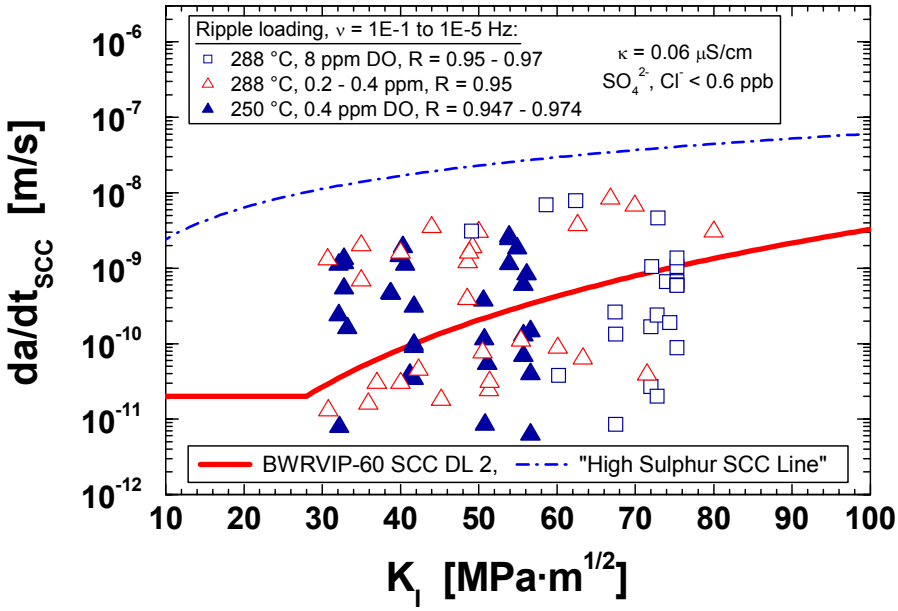

FIGURE 6: Effect of "ripple loading" on SCC CGR of different low-alloy RPV steels under BWR/NWC conditions [28]

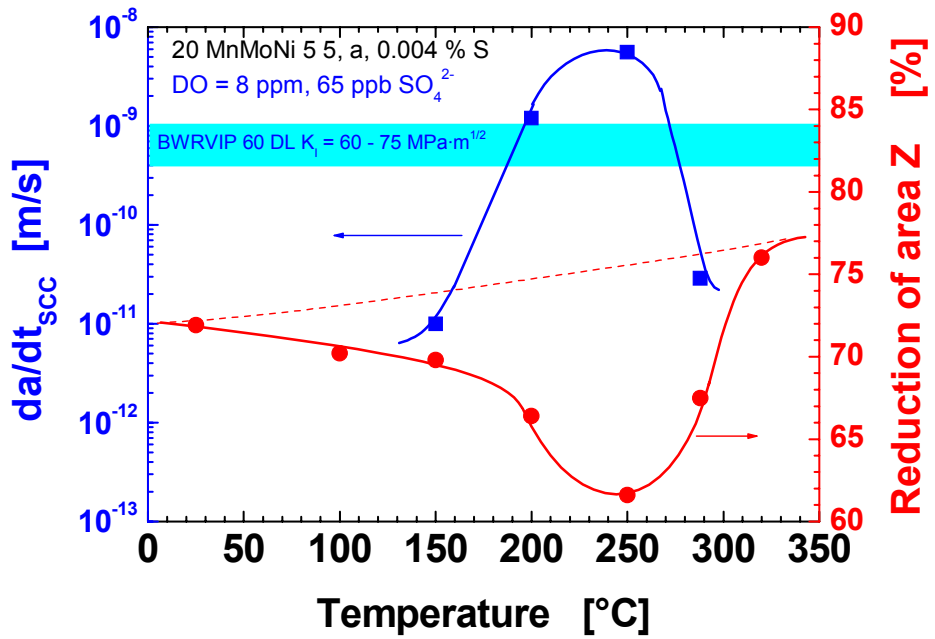

FIGURE 7: Coincidence between maximum of SCC CGR and DSA susceptibility (minimum of Z) after Seifert and Ritter [27]

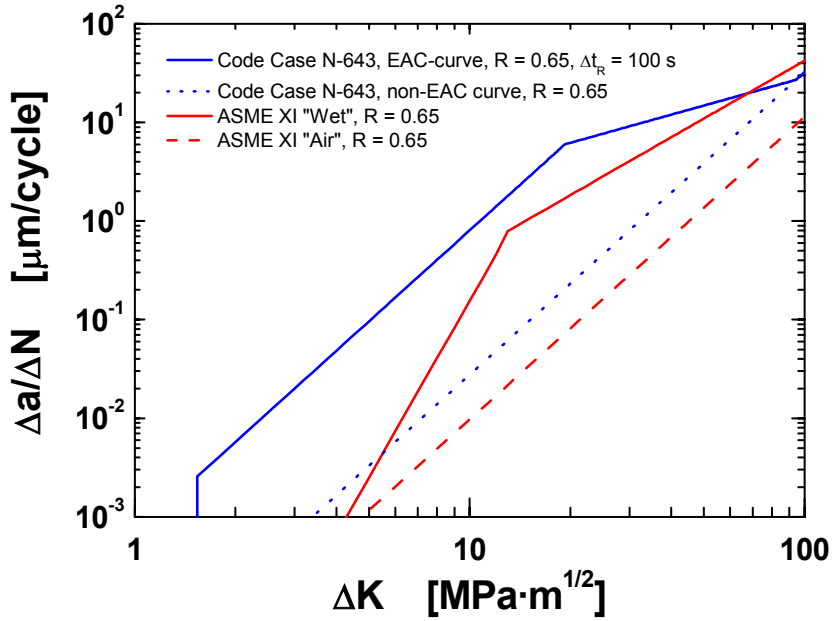

FIGURE 8: ASME Section XI CGR curves for R = 0.65 and Code Case N-643 modification (example for 100 s rise time) [3]

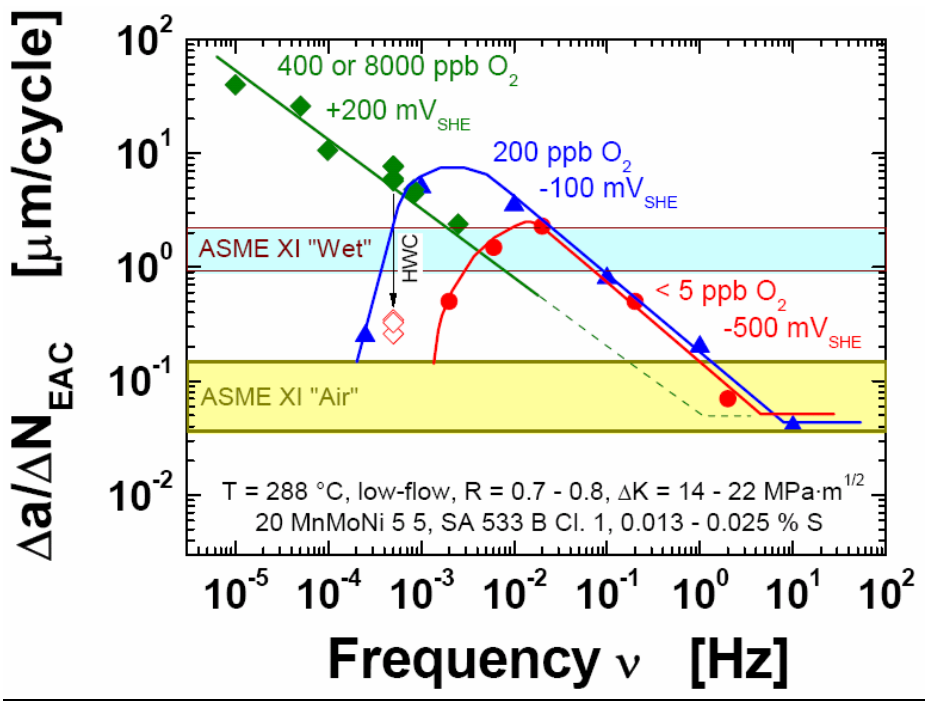

FIGURE 9 Effect of DO/ECP and loading frequency on $\Delta a/\Delta N_{EAC}$ and comparison with corresponding ASME XI reference fatigue CGR for the specified conditions [34]

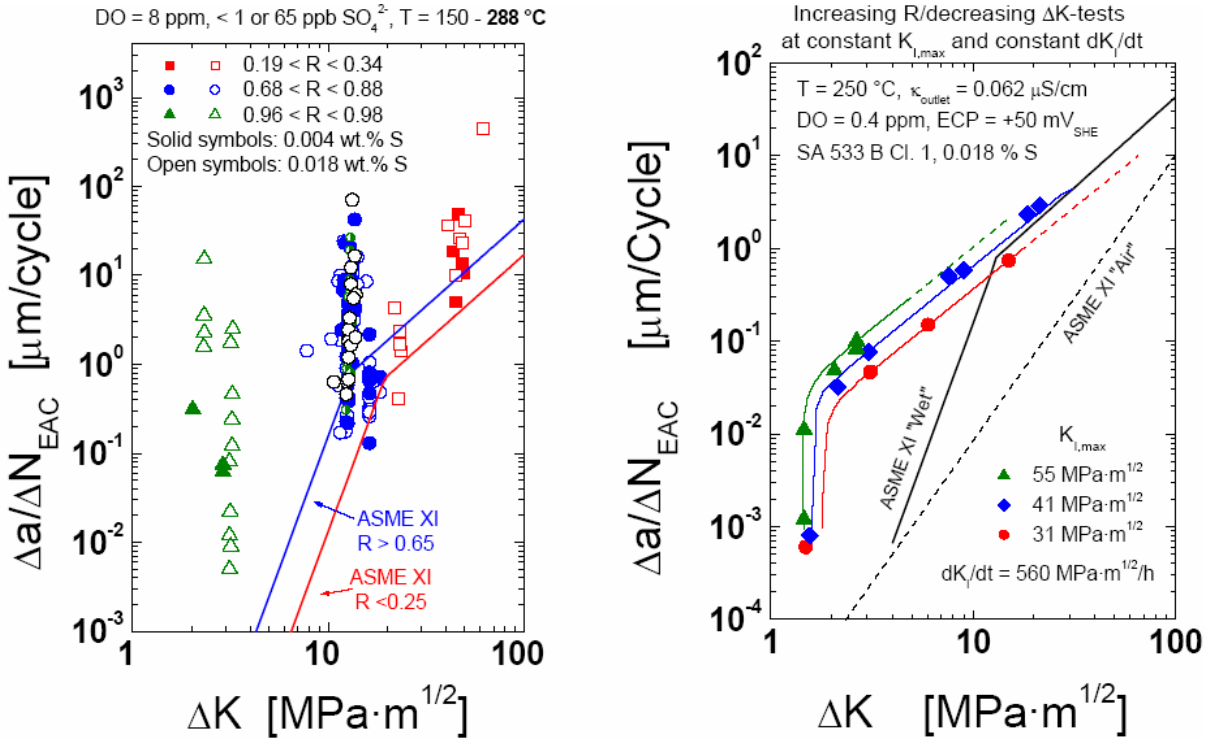

FIGURE 10: Effect of ripple loading and alternating stress intensity on $\Delta a/\Delta N_{EAC}$ and comparison to corresponding ASME XI reference fatigue CGR curves [34]

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SESSION 4: Mechanisms #2 – Oxide Growth and Exfoliation

Chairman: R. Coutant, Progress Energy

PROGRESS IN PREDICTION AND CONTROL OF SCALE EXFOLIATION ON SUPERHEATER AND REHEATER ALLOYS

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ABSTRACT

Scale exfoliation from ferritic and austenitic steels used for superheater and reheater tubes has long been recognized as a major cause of tube blockages and steam turbine erosion. A methodology based on a format first suggested by Armitt et al. in 1978 has proved to be a useful tool for providing warning of exfoliation, and has been used to aid decisions on tube cleaning and the estimation of remaining tube life. That approach uses the concept of the need to exceed a minimum level of strain energy in the scale before separation and exfoliation can occur. Equating the strain energy stored in the scale with scale thickness, hence time at temperature, allowed the use of relatively simple measurements to estimate the potential for scale exfoliation. The trend to higher steam temperatures and longer periods of full-load operation increases the rate at which oxide thickening occurs, so that increased awareness of the factors involved in scale exfoliation is required. Also, there is a need to examine the reliability of the oxide growth and exfoliation characteristics used in the present lifetime approaches in terms of operation at higher temperatures and pressures, the effects of changes in the frequency of load cycling and black starts, and the applicability of the currently-accepted mode of scale separation and loss to the new ferritic and austenitic alloys. To this end, a review of research and field experience related to oxide growth and spallation in steam, with an emphasis on results obtained over the past twenty-five years, was conducted and used as a basis for setting forth the characteristics of a high-level model for prediction and control of scale exfoliation on superheater and reheater alloys. The proposed approach is based on the Armitt et al. format, but envisions incorporation of the latest scientific understanding and field observations into a multilayered set of mechanistic and database algorithms, linked to a damage-accumulation parameter as the key tracking factor. Such an overarching model would, of necessity, link fundamental microstructural, compositional, mechanical, kinetic, and environmental factors to parameters that can be controlled or monitored at the plant level. The research, database, testing, and modeling requirements to accomplish such have been defined, and will be discussed.

INTRODUCTION

Scale exfoliation from the steam side of superheater and reheater tubes has been a problem for over 30 years, initially gaining notice when scale exfoliated from small-bore, austenitic alloy tubing led to flow restriction and blocking of tube bends, and resulting boiler tube failures from overheating. In the U.S. in the same time period, there was some concern resulting from solid particle erosion (SPE) of the nozzle blocks and first stage blades of steam turbines, due to oxide particles exfoliated from low-Cr ferritic alloys, typically T11 and T22 [1]. These problems were mainly experienced in the intermediate pressure turbine, due to exfoliation from the reheaters, in plants where the configuration of the piping allowed the exfoliated scales to be transported to the turbine. Research efforts were initiated to determine the causes of scale exfoliation by the Central Electricity Generating Board (CEGB) in the United Kingdom, and subsequently by EPRI in the US, which published a report that incorporated much of the CEGB's findings [2]. Over approximately the last five years, scale exfoliation problems from austenitic alloys have been reported worldwide [3)]; likewise, SPE due to oxides from ferritic alloys has increased in

importance, and is experienced predominately, but not solely, in North America [4]. Further, changes in operating practices, with extended running at near to full load, longer periods between scheduled maintenance, and the trend to higher steam temperatures and pressures, have contributed to mounting concerns over the increasing thickness of steam-side oxide scales. It is notable that long-term overheating due to flow restriction from exfoliated oxide scale is the second most important cause of boiler tube failures worldwide [4], and that increasing attention is being paid to the measurement of steam-side oxide thickness as a way of estimating remaining life. A further development that tends to exacerbate scale exfoliation is cyclic operation, although correlations between scale thickness, cycle frequency, and temperature change are not available. The requirement for heat-recovery steam generators to endure very rapid rates of heating and cooling suggests that they may be particularly prone to scale exfoliation problems [5]. Obviously, there is a need for the development of a rational basis that can be used by plant operators to manage, and possibly control, scale exfoliation.

CURRENT UNDERSTANDING OF SCALE EXFOLIATION

It is well understood that the thickness of the steam-side oxide increases with time (usually according to a parabolic rate law), until some critical condition is reached at which scale exfoliation can occur; since exfoliation is not experienced typically until after many thousands of hours of service, the 'critical criterion' is thought to be related to scale thickness. Loss of protective scale not only leads to the problems indicated, but also results in an acceleration of the oxidation process in the affected locations, which increases the rate of alloy consumption, and may result in the formation of less adherent oxide scales. It is also well understood that there are major differences in the rate of oxidation between ferritic and austenitic steels, since the low-Cr ferritic steels tend to form iron-scales based on magnetite (Fe_3O_4), sometimes with a thin outer layer of haematite (Fe_2O_3) [6], which are less protective than the Cr-containing spinel oxides formed by the austenitic steels.

The rate of oxide thickening increases exponentially with increasing temperature [7]. Since the ferritic steels used in the relatively old fleet of U.S. steam boilers already are operated under conditions near their oxidation limits, increasing the main steam temperature by only 10 or 15°C could result in a significant increase in the rate to scale growth on those alloys. This relationship of scale thickening to temperature suggest that exfoliation conditions may be reached in shorter times at higher steam temperatures for both ferritic and austenitic steels, which also seems to match recent experience [3].

The general understanding from earlier research [2] is that the major criterion for scale exfoliation to occur is that the level of stored strain energy in the oxide must reach or exceed the energy needed to drive a crack along a plane of weakness in either the scale itself or between the scale and the metal substrate. Stress can accumulate in oxide scales from three main sources:

1. The increase in volume that occurs when the alloy is converted to oxide; for the low-Cr steels, the ratio of the volume of the oxide formed to that of the alloy consumed is of the order of 2. In the absence of other constraints, the growing oxide scale thus typically is in a state of compression. This stress can be exacerbated or relieved by shape effects: for instance, oxide growing on the inside of a tube will be more constrained than that growing on the outside. It is not clear to what extent these or other growth stresses may be relaxed during service by, for instance, creep or other deformation of the oxide itself or of the underlying metal.
2. Thermal stresses resulting from differences in coefficient of thermal expansion (CTE) between the oxide and the underlying metal. These differences can be significant, and so can provide a large driving force for creating differential stresses during thermal transients.
3. External stresses resulting from parasitic loads, vibrations, or impacts on the oxidizing component.

Figure 1 uses data from references [2,8] to show the relative CTEs of a ferritic steel (T22) and a type 300-series stainless steel, as well as data for the oxides likely to be formed, over the range of metal temperature of interest. Given the sparsity of CTE data as a function of temperature for the oxides of interest, it

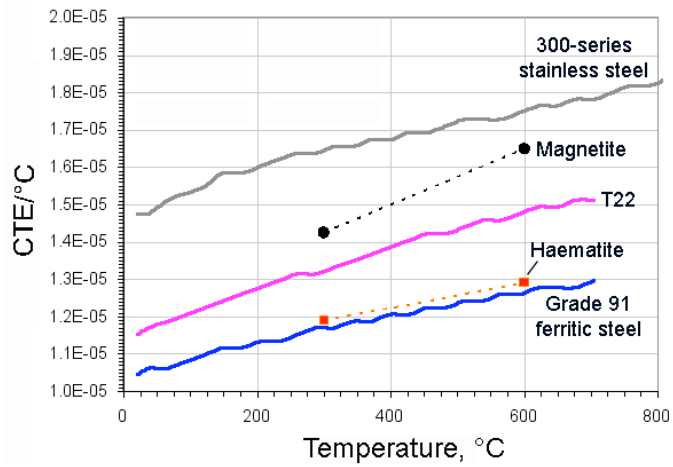

Figure 1. Temperature Dependence of the Coefficients of Thermal Expansion of Alloys and Oxides

would appear that magnetite growing on T22 will be put under compressive stress during heating, and under tensile stress during cooling cycles. In contrast, assuming that the CTE of the Fe-Cr spinel oxide that grows in contact with the austenitic steels is similar to that of magnetite (magnetite itself typically does not grow in contact with the austenitic steels, as it does on the ferritic steels), in heating-up cycles the scale on austenitic steels will be in tension, but in compression during cool down. Another way of visualizing these differences is shown in Fig. 2, which illustrates the decrease in the diameter of individual tubes made from T22, T91, a 300-series stainless steel, and the oxides magnetite and

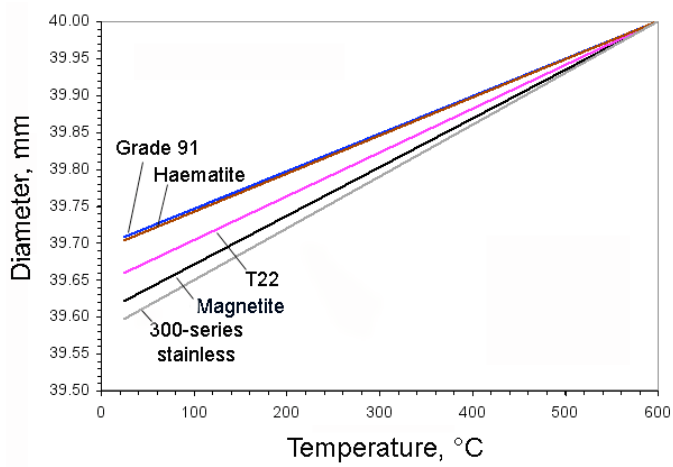

Figure 2. Decrease in Tube Diameter During Cooling, Showing Effects of Variations in CTE

haematite, due to contraction during cooling from 600 to 20°C, starting at 40 mm diameter. This clearly demonstrates the differences between the ferritic and austenitic steel tubes, with the 9Cr ferritic material (Grade T91) contracting significantly less than T22. This difference suggests that alloy T91 would be more prone than T22 to scale exfoliation. When magnetite is formed on T22, the oxide layer (in contact with the alloy) will experience a small tensile strain on cooling whereas, on a 300 series stainless steel, the magnetite would experience a compressive strain. Where a layer of hematite is grown on top of the magnetite (which typically is found more extensively on alloys which form scales that tend to increase in

protective behavior with time), the hematite will experience a compressive stress compared to the magnetite. Thus, the presence or absence of an outer hematite layer (that is, the specifics of the scale formed) can significantly influence the stress field in the main body of the scale, which is typically magnetite.

THE ARMITT APPROACH

Such considerations of the development and release of stress in growing oxide scales were used by Armitt et al. [2] to make estimations of the accumulated elastic strain as a function of scale thickness, and to relate these values to observed tendencies for scale damage and exfoliation. This overall approach was summarized very elegantly in the "Armitt diagram," shown in Fig. 3. The diagram deals with the conditions found on both ferritic (tensile cooling strains) and austenitic (compressive cooling strains) steels, and also shows the regimes where features such as through-scale cracking and the formation of

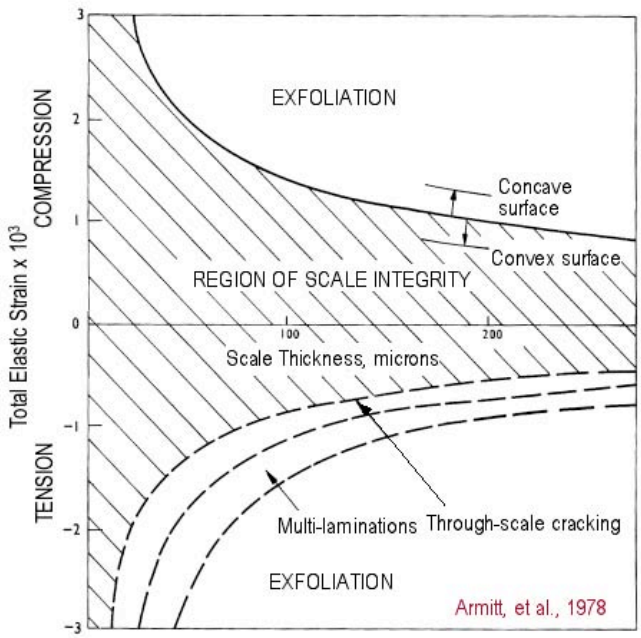

Figure 3. The Armitt Diagram

multi-laminated oxide layers are expected on ferritic steels. It is obvious that the regime of scale integrity (i.e., no exfoliation tendency) suggested by the diagram narrows rapidly with increasing scale thickness, which is a reflection of the decreasing amount of total elastic strain that can be accommodated as the scale thickness increases. The obvious practical drawback of this diagram is the need for values of scale thickness (which can be obtained from metallographic measurements on tube samples), and of the total elastic strain in the scale due to cooling. This latter value typically can be calculated from knowledge of the difference in temperature experienced by the tubes, using the simplified formulae shown in Table 1. Note that these calculations take account of the presence of haematite in the scale, with 20% haematite

Table 1. Estimation of Cooling Strains

Oxide	300-series Austenitic Steel	T22 Ferritic Steel
With 0% Fe_2O_3	$+ 1.8 \times 10^{-3} (T_s-T_a)/ (600^\circ C-T_a)$	$- 1 \times 10^{-3} (T_s-T_a)/ (600^\circ C-T_a)$
With 20% Fe_2O_3	$+ 2.0 \times 10^{-3} (T_s-T_a)/ (600^\circ C-T_a)$	$- 0.5 \times 10^{-3} (T_s-T_a)/ (600^\circ C-T_a)$

where: T_s = service temperature, $^\circ C$
T_a = temperature to which the component is cooled, $^\circ C$
-ve is tensile, +ve is compressive

in the scales on a 300-series stainless steel producing a slight increase in the compressive strain, but a decrease in the scale formed on T22. Note also that the convention used on the Armitt diagram assigns a negative sign to tensile strains.

Figure 4 shows data points superimposed on the Armitt diagram for measurements from scales of different thicknesses that were taken from superheater and reheater tubes that exhibited moderate to severe exfoliation [9]. The total elastic strains calculated for the scales formed on the austenitic steel tubes placed them in the zone of expected exfoliation, for scale thicknesses as low as 70 µm. The much thicker scales formed on the ferritic steels had reached the point of damage through cracking and delamination, but only those with thin, outer hematite layers had accumulated sufficient elastic strain to cause exfoliation.

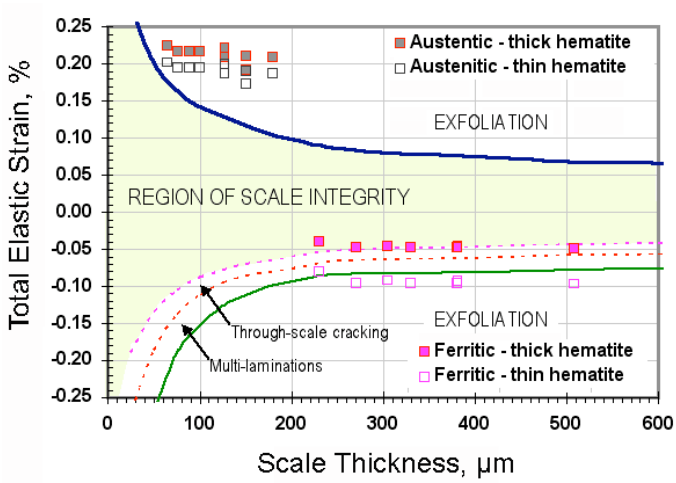

Figure 4. Data for Superheater and Reheater Tubes with Moderate-to-Severe Exfoliation

The relatively limited use in the US of the Armitt diagram approach mostly has been to supplement failure analyses to explain why exfoliation was experienced only after many years of service. Occasionally, however, the diagram has been used to predict when exfoliation is likely to occur, so that preventive actions could be completed to prevent exfoliation, and consequent damage for tube failures. The types of corrective actions that can be used include inspection of the lower bends of the superheater and reheater platens during normal outages, for which X-ray imaging can provide a very useful, graphic, nondestructive tool. Tube bends found to have significant deposits can be cleaned, or cut out and replaced. In some cases, it has been found possible to clean out blocked bends by blowing down the exfoliated oxide, using an auxiliary forced air system. Where the oxide is approaching a thickness at which, under the anticipated operating conditions (temperature cycles) the Armitt diagram suggests that exfoliation will be likely, chemical cleaning has been used to remove the oxide from the components.

The differences that exist among alloys in terms of CTE (Fig. 1 and 2) and in rate of oxide growth as a function of time and temperature could provide a rational basis for the selection of replacement materials for use in components where exfoliation has been a particular problem. Further, since the tendency for exfoliated scale to accrete into blocking deposits can be strongly affected by the hydrodynamics in the tubes, some local redesign, such as changes in tube bend radius, could be considered. The predictive qualities of the Armitt diagram also can be used to determine the most effective location for the installation of an online oxide exfoliation detection system.

BEYOND THE ARMITT DIAGRAM

Overall, the Armitt approach has demonstrated merit, even though the parameters required by the diagram currently are not readily available to plant operators. Ideally, however, an all-encompassing model is needed that will allow quantitative prediction of the size and amount of exfoliated scale debris as a function of plant operating parameters, such as time, temperature, steam conditions, and cycling parameters. An ongoing, EPRI-funded program is addressing these issues [10]. The approach being taken is to develop a coded suite of simplified logarithms that can be used to guide plant operators. These will use scale failure criteria that can be referred directly to plant operating parameters, as well as a common base parameter that includes the operating history experienced by the scale, and the effects of scale properties. The need for measurements by plant personnel will be minimized by the use of sophisticated models to calculate the parameters required. Of course, some measurements from samples collected from the boiler will be required to confirm and periodically update the models.

In the intervening time since the Armitt diagram was devised, advances have been made on a number of fronts that should allow these design improvements to be made. In particular, significant progress has been made in the detailed, quantitative description of the failure strains in oxides, and failure models now involve physical defects that can be approximated to those found in real scales. These models can now quantitatively treat fracture in tension, as experienced by ferritic steels, and account for the role of microcrack networks that develop in such scales. Models that address fracture in compression, as experienced by the austenitic steels, include treatments for the role of scale porosity, voids, surface roughness, as well as the creep behavior of the substrate [11]. One qualifying factor is that many of these advances have been made for oxide scales grown in air, not in steam. Thus there are questions concerning the extent to which air-grown and steam-grown oxide scales differ, particularly in terms of oxide composition and structure, scale porosity, and differences in the depletion of elements such as Cr from the alloy substrate.

The proposed approach for developing a successor to the Armitt diagram is summarized in Fig. 5, which is intended to indicate the continuity with the Armitt approach. In this, the scale thickness in the original Armitt diagram is replaced by a parameter (ω) that incorporates all of the various oxide property-related

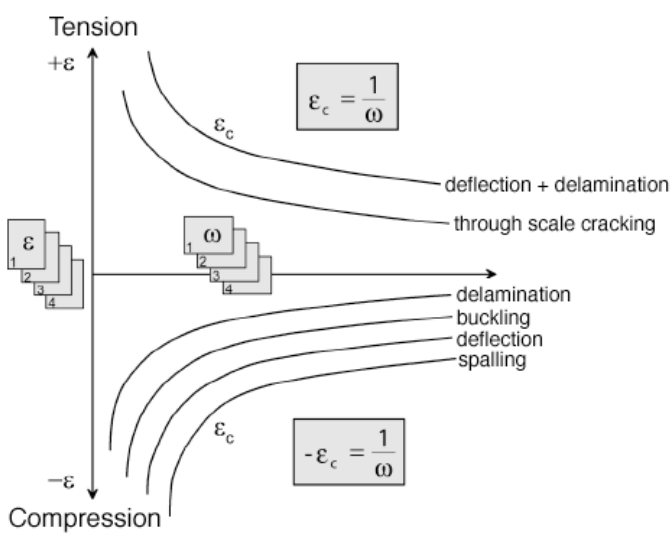

Figure 5. The Next-Generation 'Armitt Diagram'

parameters, and which essentially is the criterion for scale failure. Stored strain energy in the scale (ε) is retained as the other main parameter, but the models and equations needed to calculate this, as well as the new oxide scale property parameter, are included in the background behind the classic Armitt approach.

The different levels (1, 2, 3...) indicated in Fig. 5 contain increasing detail. As an example, for calculating the accumulated strain (ε) in the oxide:

Level 1: will represent the residual elastic strain from plant operation, which will be the sum of the strains imposed by growth of the oxide ($\varepsilon_{grow,int}$); by geometric factors that affect the oxide growth ($\varepsilon_{grow,geo}$); the stresses from thermal excursions (ε_{therm}); and strains from external loading (ε_{ext}); minus the strain relief due to creep of the oxide and/or alloy (ε_{creep}); and from other forms of deformation such as pseudo plasticity ($\varepsilon_{pseudo\text{-}pl}$). That is: $\varepsilon = (\varepsilon_{grow,int} + \varepsilon_{grow,geo} + \varepsilon_{therm} + \varepsilon_{ext}) - (\varepsilon_{creep} + \varepsilon_{pseudo\text{-}pl})$

Level 2: will include models that will allow the calculation of strain from each of these causes;

Level 3: will incorporate models that calculate specific parameters used in the Level 2 models; these will include, for instance, the temperature dependence of particular parameters. This level, or further sublevels will accept plant data as input.

For the scale property parameter (ω):

Level 1: will represent a critical strain for scale failure (ε_{crit}), where $\varepsilon_{crit} = 1/\omega$.

Level 2: will address the modes of scale cracking.

Level 3: will incorporate other models as needed. For instance, there is a need for improved models to describe the details of oxide scale failure, including delamination, cracking, and local spalling.

Level 4: will contain models for calculating the parameters required, including: oxide thickness; the elastic modulus and fracture toughness of the scale; surface energies; pore sizes; and geometric parameters. These are related to plant data through algorithms.

The input required from the plant operator will consist of data that are typically logged or are available from records, including such information as alloy type, steam temperature, time at temperature, number of cooling cycles, and magnitude of the temperature drop associated with the cooling cycles. Some form of integrated thermal history of the components of interest is needed, ideally, and suitable algorithms to extract this from typical plant records will have to be developed. These plant data will be used by the models embedded in the new approach, which will also contain alloy and oxide properties, oxidation kinetics and morphological data needed in the equations, to calculate all of the parameters required to redraw the Armitt Diagram for the specific cases considered. It is expected that it should be possible to incorporate this approach into a menu-driven, software-based tool that would be easily accessible to the plant engineer for use in determining when spallation events can be expected, for understanding the influence of plant operational parameters on tendencies for scale exfoliation, and for providing guidance for planning.

Obviously, the usefulness of this approach depends on the availability of acceptable values for the parameters used. While there exists a comprehensive, quantitative database for the oxidation in steam of a few alloys, there is a continuing need for an oxidation model that can account for the effects of steam on the oxide composition and structure, scale porosity, and subsurface zone depletion. There is also a need to extend the current knowledge base to the higher temperatures and pressures associated with advanced steam conditions. Further, the move to ultra-supercritical (USC) steam conditions will require the introduction of new alloys [12], for which there are few data available for behavior in steam. A particular characteristic of new plant designs is the intention to make more extensive use of the high Cr (9-12 Cr) ferritic steels which, by analogy to the remarks made earlier for the T91 material, may exhibit tendencies to earlier or more extensive scale spallation than do currently-used alloys. The projected final stage superheater and steam piping materials required in the USC steam plants are Ni-based alloys, such as

Inconel 617, HR6W, and Inconel 740. Research on the oxidation behavior on alloys of this type is critically needed, and several research programs are under way [13-15].

SUMMARY

Scale exfoliation is now recognized as a problem worldwide, and is expected to become even more widespread as plants are run for increased times at maximum load (that is, maximum temperature), and as steam temperatures increase with new plant designs. The Armitt diagram developed and published in 1978 provides a sound basis for predicting the tendency for scale exfoliation, but it involves parameters such as oxide thickness and stored strain energy, that are not readily accessible to plant operators. Work is in progress to build on the Armitt diagram approach, and the direction taken is to incorporate current analytical understanding of the exfoliation process to improve the representation of features found in real, exfoliating scales. The new approach is intended for incorporation into a menu-driven, software-based tool, and will be capable of using available data bases to calculate the parameters required, so greatly reducing the amount of data input required by the user. It is intended that this approach will result in a tool that can be used to provide guidance to plant operators to allow them to manage the exfoliation problem, as defined by the materials of construction and the mode of operation of each particular plant. The analytical models needed in this approach are, in principle, available now, but they need to be brought together and linked to work in the manner described. Data for testing the ability of the new system also are available for the low Cr ferritic steels, and possibly for the 300-series austenitic steels. However, new data will be required for extension of this approach to advanced steam conditions, and for the new alloys required for use in them.

ACKNOWLEDGEMENTS

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Root Cause Identification of Superheater Tube Failures in 9 Cr Martensitic Alloys

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Formulation of If-Then Rules in an expert system for the identification of the root cause of failures in superheaters have helped highlight a number of potential difficulties in determining the root cause of premature creep failures in P91 superheater tubing.

Creep failures can occur through shortcomings in the materials of construction, general overheating due to furnace and plant induced problems, and also local overheating caused by poor distribution of steam or flue gas flow. With older ferritic-pearlitic alloys it is possible to use spheroidisation, and measurements of oxide thickness, hardness, etc, to help differentiate between these "root causes" of failures. The newer 9Cr alloys have a martensitic structure that does not change significantly at the optical scale whilst undergoing creep, and oxide growth is highly dependant on small changes in composition.

It is shown that steam side oxidation of these alloys could induce premature failures due to the insulating effect of the oxide scales, which cause tube temperatures to rise. Attention is drawn to a potential "runaway effect" in which the tube temperature and rate of oxidation increase with time as the oxide builds up on the tube walls.

1. Introduction

Over the past ten years designers have turned to better materials to improve plant efficiency and make plant more capable of meeting "two shifting" requirements. But these new materials are beginning to cause problems with life prediction and failure analysis, as highlighted at a recent conference on these subjects [1].

In this context there has been the rise of the litigation culture, in which failure of a power plant at a critical time could lead to long and complex court actions to determine what was the root cause of the failure. Was it due to the materials, the design, or mistakes by the operators? A whole panoply of experts from various disciplines could be needed, few of whom would be completely objective or able to comprehend the full picture. There is a need to develop techniques that can assist technical specialists who undertake failure investigations. One such technique is to use an expert system to help with failure investigations. This paper derives from work to formulate an expert system to assist with the investigation of P91 superheater failures. However the main thrust of this paper is to show how this work has led to a consideration of how steam side oxide formation in P91 (and P92) alloys could lead to premature creep failures.

What is an expert system, and what is it intended to do? The short answer is that it is a system that uses artificial intelligence to replace human experts or to augment their expertise. The aim is to encapsulate human expertise in sets of **If -Then** type rules, to assess whether the facts about something, which has occurred, will lead to a certain conclusion.

The work at the University of Surrey has concentrated on the technique of rule formulation and the issues that relate to the marshalling of individual conclusions from each If-then rule. An important aim of the work is to show that a complex expert system can be built up by experienced engineering staff with the minimal involvement of computer specialists such as "knowledge engineers". This is being done by focusing on a piece of equipment and a material of construction that can suffer failures from a variety of different mechanisms. This procedure is vital in exposing the difficulties in constructing an expert system of some real depth, complexity, and use.

A piece of equipment that has the characteristics of being likely to fail through a variety of mechanisms, because of wide variations in the types of operation and design and materials of construction is the power plant superheater. Currently one of the most important materials used in superheaters are the 9% chromium martensitic steels. The issues involved in investigating failures of such alloys gives some real point to the development of an expert system.

2. Background to P91

In P91 chromium levels are held down to the 8-9.5% range to permit the introduction of higher levels of ferrite forming elements to enhance creep strength, at some sacrifice to oxidation resistance. P91 is now quite an established, the first superheater headers having gone into service in the early nineties. Nevertheless due to lack of experience with this material, the estimated creep stresses for this alloy vary quite markedly between the different standard authorities, as Table 1 shows [2].

Table 1: 100000 hour creep rupture strengths in MPa for P91 according to ASME, VdTÜV and EN Evaluations [Ref 2]

P91 Evaluation Method	500°C	550°C	600°C	650°C
ASME	164	141	98	---
VdTÜV	253	162	90	---
EN	258	166	94	48 (approx)

The majority of creep failures in P91 superheater tubing will have resulted from a moderate degree of overheating, with failures occurring after some tens of thousands hours of operation. When a creep failure has occurred, a simplistic approach is to think that there are likely to be only a few root causes. Something might be amiss with the furnace design or operation, leading to excessive metal temperatures. The alloy itself is deficient. In this case the creep strength may be somewhat lower than anticipated, or corrosion on the flue gas or the steam side of the tubing, has led to excessive thinning, raising the stress level.

Hence, as well as focusing on the material, a good expert system would activate sets of If-Then rules, based on steam and flue gas temperatures, water and steam flows, and energy inputs and outputs to and from the furnace. This would enable the expert system user to assess whether the root cause was due to plant, or operating derived, problems of the following type.

- **Operation of furnace at design limit or higher**
- **Bad flue gas distribution**
- **Bad burner set up**
- **Air in-leakage in the furnace**
- **Furnace wall slagging**
- **Fouling of economiser or air heater**
- **Switch to natural gas from coal or oil firing**
- **Switch to low NOx burners**
- **Excessive air to fuel ratio**
- **Need to by-pass feedwater heater**
- **Continuing low steam flow**
- **Weather factors**

3. Estimating Temperature of Failed Tubing

Many creep failures in superheater tubing result from some deficiency in the operation of the furnace or from a starvation in the steam flow. In determining the actual cause it is helpful to establish the temperature gradient along the failed tube and the temperature in neighbouring tubes. This would suggest whether just the one, failed tube, was suffering from a blockage, or whether there was a general problem of overheated tubes. Estimating temperature is reasonably straightforward with the lower alloy steels, the main techniques being:

- **Use of the exposure time of the failed tube using a Larson-Miller or other Life/Stress/Temperature extrapolation technique**

- **Steam side oxide thickness**

- **Spheroidisation of pearlitic and bainitic carbides using optical microscopy**

- **Levels of grain boundary cavitation**

- **Coarsening of sub-optical carbides and interparticle distances using SEM observations**

- **Drop in hardness caused by carbide coarsening**

The first approach to estimating tube temperatures would be based on the failure time using a Larson-Millar parametric method. But the spread in estimated creep properties, shown in Table 1, indicates that there may be problems with this method. In this respect a paper in *Materials at High Temperature (MAHT)* by the present authors highlights the considerable range in the values for the Larson-Miller constant ranging from 38 to 20, which greatly influences temperature estimates [3].

In the *MAHT* paper the authors have also shown that the classical microstructural methods for estimating temperature or remaining creep life are problematic [3]. Spheroidisation does not occur in martensitic alloys of the P91 type, and with other methods there is a considerable spread in the data, for example hardness changes. In addition these microstructural changes are strongly influenced by the level of stresses as well as the operating temperature.

4. Problems in Using Oxide Thickness to Determine Tube Temperatures

A common technique of estimating temperatures is to use steam side oxide thickness. The attraction of this is that it can be done in-situ using ultrasonic techniques. The problems in applying this to the 9Cr martensitic types are illustrated in Figure 1. This shows the one-year metal loss rate using data from a paper by Ennis and Quadakkers. Note the dramatic increase in oxidation resistance as the chromium level changes from 9 to 10.5% [4].

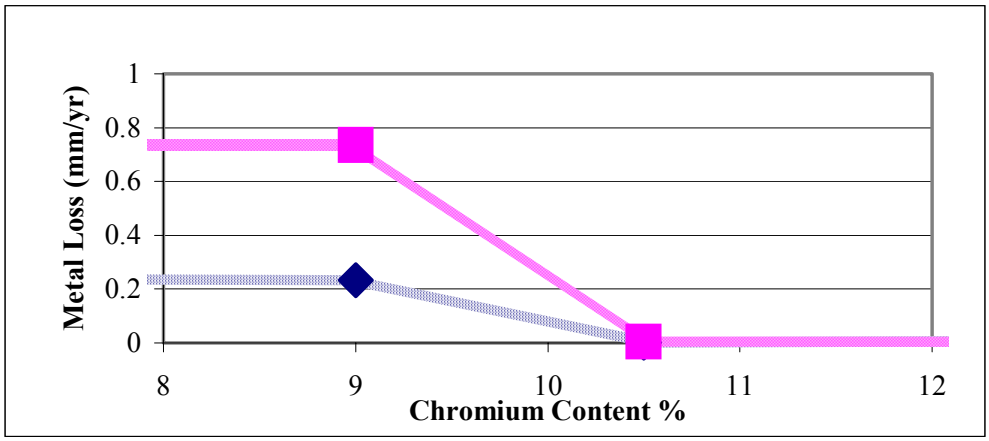

Figure 1 Effect of chromium content on oxidation rates at 600°and 650° in steam

Because of the marked effect of chromium it would be difficult to use oxide thickness as a reliable technique for temperature estimation. It is also known that variations in the levels or silicon, and possibly manganese and nitrogen, will also influence oxidation resistance. Hence caution is needed in using oxidation data because of the scatter from the effects of second order elements.

At this stage only tentative If-Then rules can be written to take into account the effect of composition on the oxidation rate. Within the specified compositions for P91 there is no definite point at which the levels of chromium and silicon will give good protection. For this chromium levels would need to be in excess of 10.5%. What can be stated quite definitely is that if the chromium content is below 9% the steam side oxidation rate will be high and overheating and tube blockages are to be expected.

The corollary is that below a chromium content of below 9% chromium the oxidation rate is unaffected by composition and can be used to estimate tube or header temperatures. The appropriate If –Then rule would be:

If the chromium is less than 9% **Then** if heat_transfer_coefficient is known it will be possible to estimate average_metal_temperature

Figure 2, which used results taken from a paper by Tamura et al on the oxidation of various grades of NF616 (i.e. P92 type alloy) at 650°C in steam, suggests that there is also no definite point at which the level of silicon becomes protective [5]. Schűtze et al consider that silicon,

rather than forming a protective sublayer slows down the loss of chromium and may help in repassivation once oxide cracking and spalling occurs [6]. The If-The rule in this case could be:

If silicon_content is below 0.15% **Then** high_rates of oxidation in steam are possible

Where there is argument about how much oxidation may have contributed to a premature creep failure it would be necessary to subject the material to an accelerated oxidation test in steam.

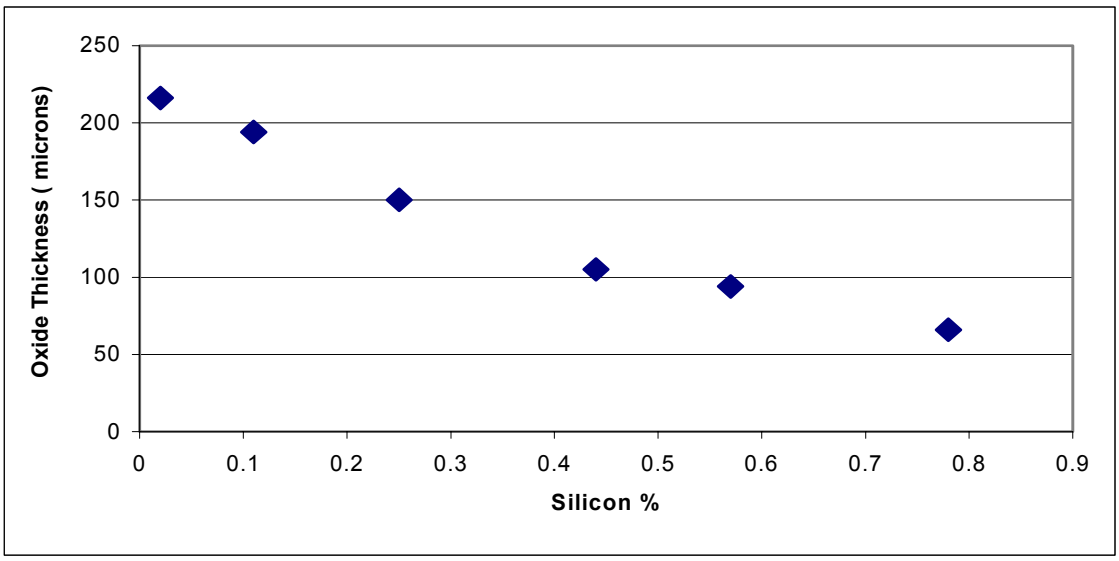

Figure 2: Effect of Si content on oxidation of NF616 alloys
at 650°C for 1000 hours in steam

4. Effects of Oxide Scale Build Up on Tube Temperatures

Identification of root causes is made more difficult if the tubing forms a relatively thick oxide layer on the steam side of the tubing, as is the case with both P91 and P92. As the oxide on the inside of the tube builds up, it acts as an insulating barrier to the heat being transmitted through the tube walls, thereby raising the tube temperature. The magnitude of the temperature rise is proportional to the heat transfer rate in superheaters, the oxide thickness, porosity and adherence and inversely proportional to the conductivity of the oxide. Data for heat transfer rates is difficult to obtain but French indicates a range varying from 19-63 $kW.m^{-2}$ and Husemann quotes 50-75$kW.m^{-2}$ [7,8]. It should be noted that this is the steam side heat transfer rate, which is significantly higher than that on the flue gas side, the increase resulting from the difference between the inside and outside diameters of the superheater tubing.

Figure 3, based on largely on the paper by Husemann, shows that, in the absence of heat transfer, or the formation of a thick oxide, a superheater tube, running at a constant metal temperature of 600°C, would use up about 1.6% of its life over a year. However at a heat transfer rate of 50kW per sq metre, the build up of the oxide scale gradually raises the tube temperature by about 17°C over a year. This progressive increase in temperature reduces tube life by about 4%.

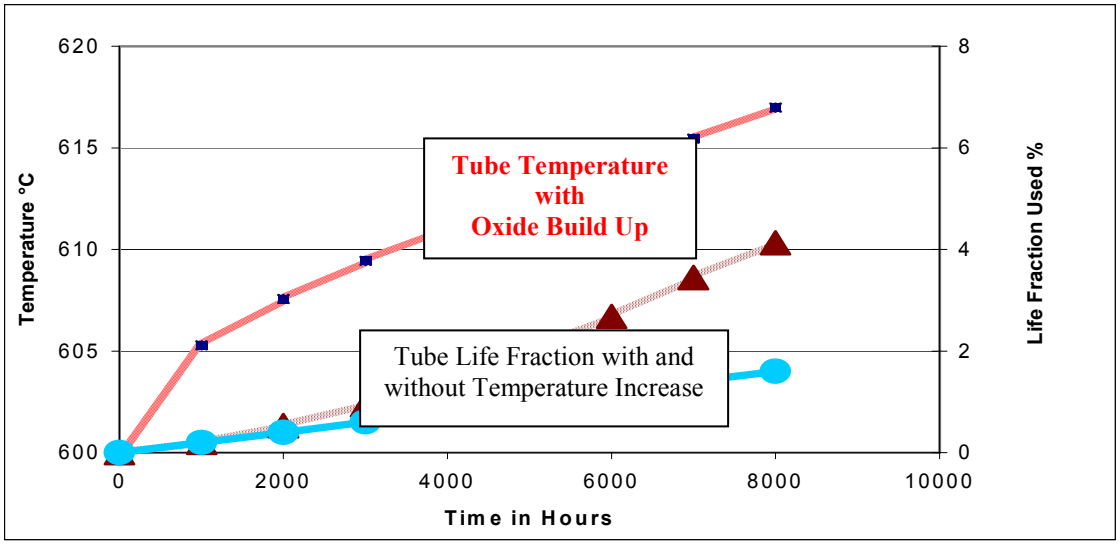

Figure 3: Effect of oxide build up on tube temperatures and life at 50kW.m^{-2}

These particular calculations **assumed that the oxide growth was determined by the original metal temperature**, that is 600°C. The hypothesis is that oxide growth rate is determined by the rate of reaction between molecules of steam and metal ions, which arrive at the outer surface of the oxide. But it would seem that it is just as likely that it is the rate of diffusion of ionic or molecular species through the oxide scale which is the rate determining step. As the oxide thickens up, the average temperature of the oxide will increase, with the rates of diffusion also increasing. It will lead to the "runaway effect" at high rates of heat transfer, whereby the formation of oxide will lead high metal temperatures and hence high higher rates of oxidation and so forth.

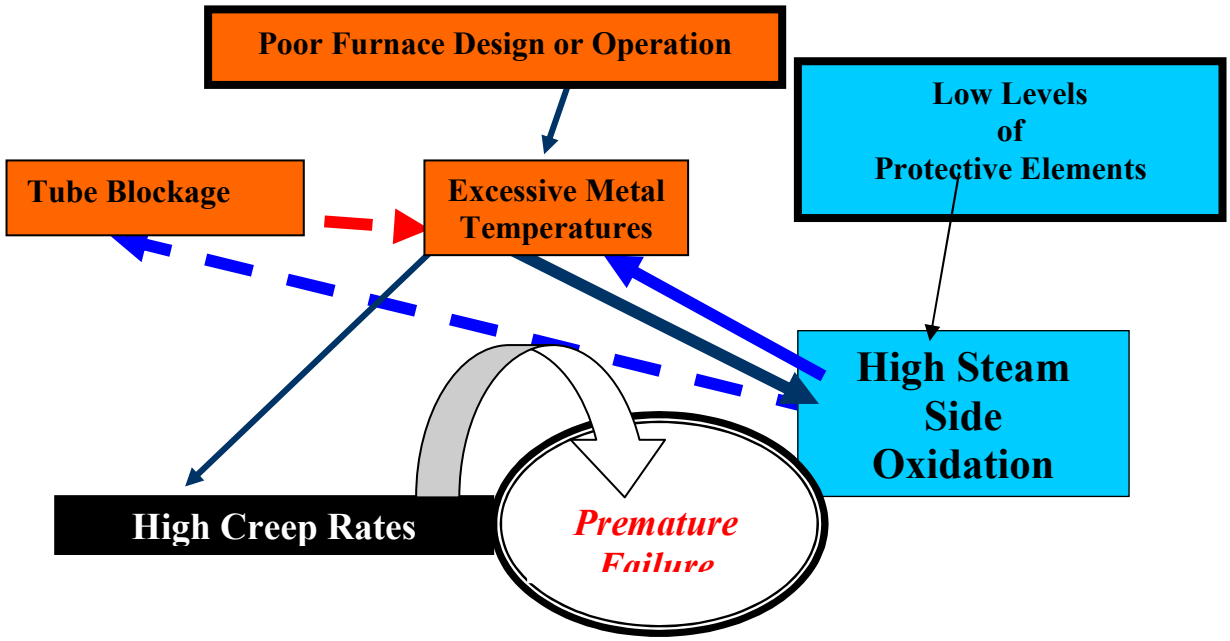

Fig 4: Development of runaway oxidation whereby either poor furnace design or excessive oxidation rates can result in high creep rates

The oxide thickness calculation was done in 1000 hour steps, with the temperature increase induced in the tube at the end of each step being used calculate the increased oxidation rate in the ensuing step. The effect of these step changes in temperature on tube life usage was calculated using a Larson Miller parameter approach for the effect of each 1000 hour exposure at the different temperatures. Note that the absolute life is much higher than the design life as normally understood. Actual values used in the current version of the spreadsheet are

- **Larson Miller Constant: 31**
- **Absolute Life: 500000 hours at 600°C**

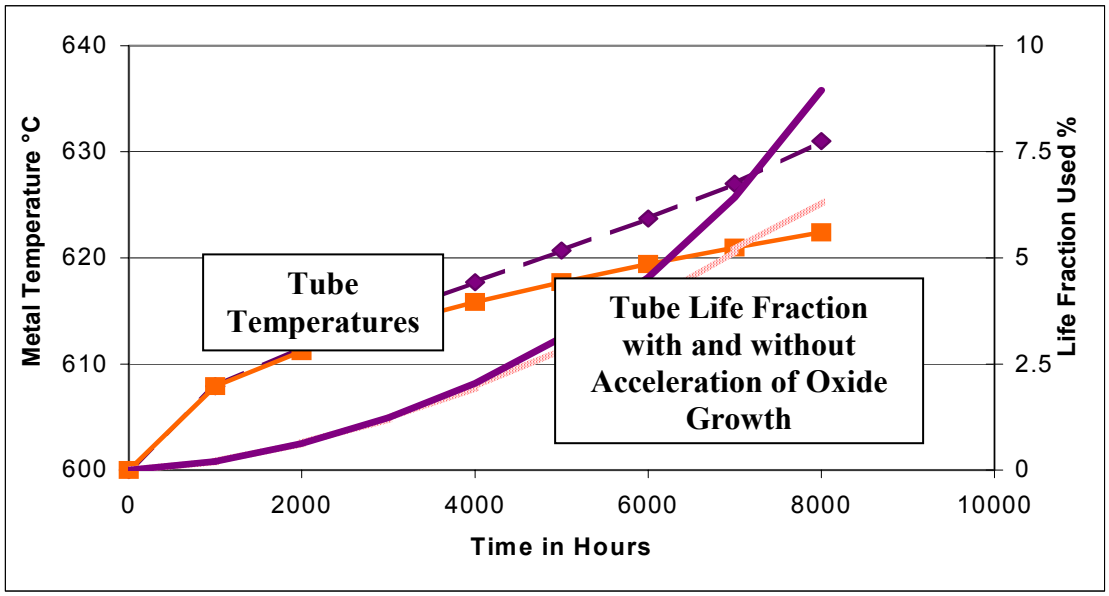

Figure 5: Tube temperatures and life fractions with and without acceleration of oxide growth at 75kW.m^{-2}

In Figure 5, the dashed curves show the magnitude of the runaway effect at a heat transfer rate of 75 kW.m^{-2}, indicating that runaway increases the tube temperature by about 9°C after 8000 hours, over the build up due the oxidation rate being fixed at the 600°C level. Tube life suffers, runaway raising the life usage from 6.32% to 8.95%, as shown by the solid curves. **Note that the runaway affect on temperature does not become really apparent until several thousands of hours have elapsed.**

An appropriate If-Then rule would be:

If chromium is less than 9% **Then** oxide build up possible root_cause of premature_creep_failure

However the runaway effect becomes far more marked if the oxidation resistance decreases, especially when combined with high rates of heat transfer. Table 2 summarises these effects at heat transfer rates of 50, 62.5 and 75kW.m^{-2} and with oxidation rates higher and lower than those quoted above. For comparison figures for the "no acceleration-no runaway effect" are also included in brackets at the 100% level.

Table 2: Effect of changes in oxidation and heat transfer rates on tube life after 8000 hours exposure

Oxidation Rate Compared to Standard at 600°C	Life Fraction Usage at Heat Transfer Rate of $50kW.m^{-2}$	Life Fraction Usage at Heat Transfer Rate of $62.5kW.m^{-2}$	Life Fraction Usage at Heat Transfer Rate of $75kW.m^{-2}$
75%	**3.25%**	**4.00%**	**5.05%**
100%	**4.31%** (4.03)	**5.99%** (5.15)	**8.94%** (6.32)
125%	**5.99%**	**10.55%**	**21.64%**

7. Discussion

There are clearly a number of potential problems in the identification of the root cause of creep failures in superheater tubes. The basic aim of such an investigation would be to decide whether the problems originated from the design or operation of the plant or whether it was caused by deficiencies in the tube material. Some of the difficulties stem from the uncertainty in estimating the metal temperature, since an excessive temperature might point towards a design problem. Unfortunately none of the usual methods based on parametric calculations, oxide thickness, hardness or cavitation provides a reliable figure with P91. A recent paper by P. Seliger and Gampe broadly supports this conclusion [9].

In these circumstances it will be necessary to use temperature estimates based on heat transfer in the furnace and superheaters. And where heat transfer rates and superheater tube temperatures appeared to be excessive, this might point to unduly high flue gas temperatures or flow rates. Again plant based calculations, and where feasible, measurements, would be needed. High flue gas temperature would indicate a possible root cause, examples of such being furnace slagging, high levels of excess air, too much flue gas recirculation, over-firing etc. Flue gas temperatures would need to be calculated from the amount of fuel being burnt, the level of combustion air and the heat abstracted in the furnace to evaporate water. Rates of flue gas flow would be calculated from the flue gas composition and knowledge of the fuel input and composition.

Given this data it would then be possible to make a considered estimate of peak tube temperatures and heat transfer rates, taking into account the position of the failed tube in the superheater bank. The main shortcoming would be that these estimates would give average values. Ideally they would need to be combined with direct measurements of the outlet temperature of the steam in the failed tube, or failing this estimates based on the thickness of steam side oxide. This only seems possible if the chromium content of the alloy is below 9%, when the oxide thickness should give a reasonably reliable value. The best that can be said for changes in hardness is that they will give an idea of the tube-to-tube temperatures.

The efforts to develop If-Then rules of high reliability, for failure analysis, have highlighted the possibility of "runaway oxidation" in superheater tubes when the steam side oxidation resistance is relatively high. The hypothesis is that, as the metal and the oxide temperature builds up, as a result of the growth of an insulating oxide, the oxide growth rate increases, thereby pushing up temperatures still further. But even without runaway oxidation, the formation of a steam side

oxide would have a marked effect on superheater temperatures and life. Here it should be noted that the oxidation resistance of P92 is only about half that P91, because its composition has been geared towards maximising creep strength. In summary, there are potential problem with the 9Cr martensitics, especially when the chromium content is below 9% and the heat transfer rate is high, that is above 50kW.m $^{-2}$

Thick oxide scales can also cause overheating if they spall off, the debris collecting as a mass in the bends or the headers of the superheaters, blocking steam flow and raising the temperatures of partially blocked tubes. This is most likely to happen after a shutdown to room temperature.

8. Conclusions

The development an expert system for the failure analysis of superheater systems in power plant has highlighted a number of issues relating to the use of P91 martensitic steels for superheater tubing. These are:

- Reliable techniques are not available for estimating tube temperatures. Larson-Miller based calculations are suspect.
- Indirect methods will need to be used based on steam and flue gas side heat transfer calculations.
- Oxide formation on the steam side of superheater tubing could lead to a foreshortening of tube life of P91/P92 materials due to the relatively high oxidation rate of these alloys.
- There is the possibility of runaway oxidation at high heat transfer rates.
- The work has also shown that the formulation of rules, in expert systems, can largely be done by the experts themselves without the intercession of knowledge engineers.

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SESSION 5: International Approaches to Tube Failures

Chairman: T. Kirwan, ESB

IMPACT OF DE-REGULATION ON BOILER TUBE FAILURES; A UK PERSPECTIVE

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ABSTRACT

Upon de-regulation of the nationalised power industry in England and Wales in 1990, the successor companies inherited a fleet of ageing plant, much of which fired indigenous coals that showed a propensity for both fireside corrosion and fly-ash erosion. The arrival of competition, together with the advent of large gas-fired plant, radically changed the operating regimes experienced by these coal- fired boilers, some of which never saw the decade's end. Base-load generation was progressively replaced by demands to two-shift, a transition to imported coals precipitated by contraction of the indigenous coal supply and compliance with more demanding environmental constraints through the introduction of low-NOx technology. More recent legislation has seen experimentation with a range of biomass fuels.

This paper details how changes in the theatre of operation have impacted upon the character and magnitude of the tube failures experienced on UK-coal fired boilers. Measures taken to mitigate the failure threat are described and future trends anticipated.

INTRODUCTION

The power industry in England and Wales covers an area equivalent to that of a medium sized State, such as Wisconsin, and yet generates enough electricity to satisfy a population of 49 million, twice that of California. For much of the second half of the twentieth century, this demand in terms of generation and transmission was met through the concerted efforts of a nationalised, government controlled agency, the Central Electricity Generating Board.

The passage of the Electricity Act through Parliament in 1989 heralded the deregulation of the state-owned monopoly, transferring the generating assets, with the exception of the nuclear capability, into private ownership. Since the realisation of this objective in early 1990, the advent of competition in the power market has radically changed the theatre of operation for the flagship coal-fired stations built in the late 1960s and early 1970s, notably through;

- the rapid expansion, and base-load operation, of gas-fired CCGT plant, both by the existing generating companies and independent power producers (IPPs)
- the demise of the indigenous coal industry, and,
- the introduction of increasingly onerous environmental legislation.

This paper explores how liberalisation of the power industry in England and Wales has impacted upon the mode, pattern and frequency of boiler tube failures in ageing, 500MW coal-fired plant of different designs and firing configurations during the final decade of the 20th century.

BACKGROUND

Pre-1990

In 1881, almost exactly 50 years after Michael Faraday had applied the principles of electromagnetic induction to develop the first electric generator, the world's first municipal power station was commissioned at Godalming, approximately 20 miles south-west of London[1]. From this tentative, pioneering start through to the early decades of the 20th century, the UK electricity industry expanded rapidly through a collection of numerous, small, relatively inefficient, municipally owned, power plant, fuelled almost exclusively by indigenous coal supplies (Figure 1).

However, during the late 1940s, it was evident that the nation's post-war economic development would be seriously compromised unless the size and efficiency of operational plant was increased[2]. Towards achieving these requirements, the plethora of privately owned operations came under government control, initially as the British Electricity Authority and subsequently, in 1958, the Central Electricity Generating Board (CEGB). Under national management, generating capacity increased five-fold, the development of 500 and 660MW coal-fired plant in the late 1960s and 1970s complementing the earlier introduction of oil-fired and nuclear powered plant, the first genuine challenge to coal's supremacy in UK power generation (Figure 1). By the 1960s, improvements in design, combustion, available construction materials and water chemistry enabled twice the electricity to be generated from a ton of coal than 25 years previous.

Post-1990

PowerGen and National Power, the two companies formed by the break-up of the CEGB, inherited a diverse range of plant with capacities of between 100MW and 660MW firing coal and/or oil (Figure 2). However, almost from inception of the new era, the emergence of relatively cheap gas-fired generation (CCGT) operated both by new entrants and existing players irrevocably changed the commercial landscape. Enabled by the then recent maturity and availability of large-scale combined cycle gas turbine technology, this departure from more traditional fuels was made attractive by the low-erection costs for gas fired plant, the availability of cheap gas and ready compliance with obligations under the Kyoto Protocol to reduce emissions.

Despite the contractual rather than statutory obligation to supply electricity since privatisation, the power industry in England and Wales has maintained approximately 23% spare capacity, as it had since the 1970s. The marked growth of gas-fired generation has, therefore, been at the expense of the smaller, less efficient coal and oil fired boilers built in the 1950s and early 1960s (Figures 1 and 3). Meanwhile, the 'flagship' stations of the late 1960s and 1970s have experienced radical changes in operating regime, base-load operation being progressively replaced by demands to two-shift and even double two-shift.

The nationalised UK power industry had been inexorably tied to the indigenous coal reserves, the coal-fired stations almost invariably being sited within established coal-fields, sometimes even being positioned at the pit head. However, as the remaining coal-fired plant fought to preserve their share of the shrinking available market, the deep-mined local supplies became increasing less competitive, such that stations have been increasingly sourced from by coals the world market, predominantly the US, Poland, South America, South Africa and Australia. Whilst reducing the net cost of generation and frequently mitigating SO_x emissions, the delivered coals generally show a marked departure from the fuels for which the boilers had been designed, with the potential to impact upon tube integrity, both positively and negatively, with regard to corrosion, fly-ash erosion and sootblower erosion.

Aside changes to low sulphur fuel deliveries, companies have also sought to meet increasingly stringent environmental legislation through the retrofit installation of low-NOx burners and back-end Flue-Gas De-sulphurisation (FGD) plant.

IMPACT ON BOILER TUBING

Source Data

Since 1973, every tube failure that has occurred on fossil fuelled boiler plant of 100MW capacity, or greater, operated by the CEGB and many of its successor companies has been recorded on a database maintained at Power Technology. Interrogation of the acquired data employing complementary analytical routines enables rapid quantitative assessments to be made of the failure risk at a given station, or group of stations, highlighting existing and emerging areas of concern and allowing pre-emptive action to be implemented towards improved availability[3].

The present analysis of this 22,000 record database has been confined to a collection of 500MW boilers that survived the closures precipitated by the post-1990 'dash for gas'. All the boilers under consideration had operated beyond their nominal design life (100,000 hours) in 1990 and many had subsequently accumulated greater than 200,000 hours service by the end of the current review period in 2000. Most of this group operates at a final steam temperature of 1055F (568°C) and at pressures of 2320 and 580 psi (160 and 40 bar) in the superheater and reheater circuits respectively. Otherwise, the analysis covers a diverse range of boiler designs and operating conditions;

- tangential and front fired boilers,
- natural and forced circulation,
- all-Volatile Treatment (AVT) and caustic boiler water chemistries,
- tangential and membrane walled furnace walls.

Within the paper, reference is made to four main statistical groups of tube failure mechanisms which dictate the pattern of such failures with operational service and, therefore, the approach to their control[3]. Wear-out mechanisms include creep, fatigue and wastage and are time dependent, ageing problems addressed through condition monitoring activities. Repair-fault mechanisms, of which defective welds and tube manufacturing defects are typical, are almost invariably a function of quality control. Random mechanisms relate to transient events such as flow starvation and faulty sootblowers, the damage arising over a very short time period. The miscellaneous grouping comprises incidents for which information is too sparse to discern the cause or which don't comply with the other three groupings.

General Trends

The transition towards a more commercially orientated business in which coal-fired plant became increasingly marginalised demanded that the boiler engineer effectively manage the boiler tube failure threat within finite budgetary constraints, but without compromising plant availability. Statistics for the decade either side of the 1990 watershed endorse the view that these goals were achieved (Figure 4).

Planned maintenance activity performed on the ageing plant during the late 1980s and very early 1990s tempered and/or arrested failure sequences associated with wear-out mechanisms such as fly-ash erosion, coal ash corrosion and creep, contributing to a downturn in failure frequency in the period immediately following de-regulation (Figure 5). However, from 1993 to the end of the decade, the failure rate climbed, unabated, three-fold. Paradoxically, the availability-loss due to tube leaks that had remained relatively constant during the decade preceding de-regulation, steadily fell to less than half the 1990 figure by the millennium (Figure 4).

This apparent contradiction derives from a progressive change in the dominant damage mechanisms post-privatisation. Greater attention to quality control, both at breakdowns and overhauls, contributed to a steady decline in the frequency of 'repair-fault' failures, such as defective welds, for most of the decade, whilst the rate of 'random' and miscellaneous causes remained constant (Figure 5). Against this background, the incidence of the already dominant 'wear-out' causes spiralled upwards, but not through creep, corrosion, erosion and other mechanisms that invariably cause 'violent' failures that force extended boiler down-time. Such failures actually diminished over this time period, in part due to

proactive, strategic maintenance at overhauls, guided by routine condition monitoring, but also associated with other factors over the same time period which are detailed in subsequent sections. That these improvements did not arrest the failure rate was a consequence of a pronounced and progressive escalation in fatigue related tube leaks, including corrosion fatigue. The repair of these relatively small tube leaks was often deferred for several days without compromising the integrity of adjacent tubing, although such decisions were, and remain, subject to the experience of the boiler engineer. This characteristic enabled Stations to exploit opportune periods off-load, particularly at weekends, to effect repairs without impacting upon availability.

Fatigue related failures exhibit a distinct bias to the evaporator circuit and, consequently, have had a profound impact upon the distribution of tube failures between the different boiler circuits since 1990 (Figure 6). Prior to this date, approximately 35% of all failures affected evaporator tubing, 28% the superheater circuit, and 20% and 15% the reheater and economiser sections respectively. However, by the end of the 1990s, almost 50% of failure incidents occurred in the evaporator circuit, whilst those in the superheater circuit now accounted for approximately 20%, with reheater and economiser tube leaks maintaining their proportion of the total. Significantly, the latter three circuits had a greater contribution to EFOR relative to their failure incidence than those in the waterwalls.

Fatigue (Stress Cracking)

Already one of the dominant mechanisms on UK coal-fired plant, the post-1990 transition to more flexible operating regimes was always anticipated to intensify the propensity for fatigue related damage mechanisms. Although this was realised, a climb in such incidents above the background level was not evident until the mid-1990s, from whence a sustained 2 to 2.5 fold increase occurred in the final half of the decade (Figure 7).

External fatigue related failures have traditionally shown a distinct bias towards the steam generating circuit (Figure 7). Discrete peaks in failure rate, usually in the waterwalls, have arisen from emergence of failures at specific locations, for example header stub welds and attachments local to access doors, burner ports and sootblower apertures. Once recognised, these have generally proved amenable to control through routine NDE and proactive maintenance activity at statutory and opportune shut-downs. Whereas the frequency of fatigue failures has remained relatively constant in the other boiler circuits, the overall escalation in failures has arisen almost exclusively in the evaporator section where this mechanism is responsible for almost 50% of the leaks, as compared to 33% leading-up to privatisation (Figure 8). Tube-wall attachments have proved the most susceptible position, this being associated with the poor access for inspection and/or the non-specific nature of the problem which has often precluded effective elimination/mitigation of a known problem. However, as detailed earlier, relatively few incidents incur forced downtime, with the commercial impact being limited to the modest labour and materials charges.

Corrosion Fatigue

Corrosion fatigue failures were relatively infrequent prior to the mid-1990s, although how many events were incorrectly assigned to external fatigue cracking during this period will remain unknown. Subsequently, the incidence of failures climbed sharply such that, at the decade end, only external fatigue failures occurred more frequently. Whilst all boiler designs have experienced corrosion fatigue damage, with incidents arising local to economiser and primary superheater inlet headers, the failures have predominantly affected waterwall tubing, with a distinct bias to lower sections of natural circulation boilers (Figure 9).

Investigations have tentatively linked the damage to boiler starts, the period when control of water chemistry is most difficult and thermally induced stresses are most pronounced. Further studies have explored the greater susceptibility of the evaporator circuit in natural circulation boilers to this damage mechanism. Temperature monitoring has identified the development of pronounced thermal variations throughout the evaporator circuit during relatively short shut-downs, the exposed metal-work towards the bottom of the furnace cooling to ambient temperatures whilst the steam-drum, insulated in the

penthouse, retains its heat[4]. The release of this warm fluid into cold components during hot/warm start-ups brings about marked temperature stratification in feeder pipes and furnace inlet headers that causes the latter to bow or rotate. As a consequence, very high stresses can be induced at header stub positions and also at membranes or attachments between adjacent tubes that initially operate at different temperature, courtesy of their respective stub position around the header circumference. Although the damage is frequently associated with positions of restraint local to the bottom dead-air space, including flame-shield attachments, internal corrosion pitting on horizontal tube runs has also served to initiate cracking, as have attachment positions higher up the furnace wall, such as at windboxes and overly stiff furnace corners.

Opportunities for repeat failures have generally been minimised by inserting, rather than pad-welding the affected tube lengths. More extensive replacements have been undertaken at overhauls where a problem area has been identified, often incorporating design improvements, such as flexibility loops and the selective release of overly stiff attachments, to mitigate the future failure risk. However, the continued emergence of new problem areas in the evaporator circuit has continued to push the failure rate upwards, warranting the retrofit installation of off-load circulation systems on some boilers to temper the thermal stratification.

Furnace Wall Fireside Corrosion

Furnace wall fireside corrosion arises when strongly reducing conditions associated with close flame proximity (impingement) preclude the development of protective oxides. These environments also provide a stable medium for aggressive gaseous species such as H_2S and HCl to exist and exacerbate metal loss rates[5].

Many UK stations experienced worsening fireside corrosion during the early 1980s. This was attributed to progressive increases in mean Unit load during the preceding 4-5 years. The perception was that the greater throughput of fuel and air expanded the flame envelope to encourage wall impingement, although the operation at higher loads would also have exacerbated inherent faults/deficiencies in the combustion system, whether associated with design or component degradation, to the same end.

By the late 1980s, the impact of furnace wall corrosion had been much reduced through optimisation of combustion settings, improved monitoring at surveys and the selective installation in the problem areas of faceted tubing and/or employing more corrosion resistant materials in composite tube form[6]. Coincidentally, low NO_x burner systems were being retrofitted to comply with environmental legislation, an exercise that was not completed until the early 1990s. Whilst the implementation of low NO_x technology, usually SOFA (separated overfire air) systems, has intensified wastage rates in many US utilities where NO_x targets are more stringent, marked reductions in furnace wall fireside corrosion rates were observed on all UK boilers, particularly the tangentially-fired boilers. This was attributed to isolating the furnace wall tubes from the highly corrosive flame environment with a blanket of secondary air and promoting a more diffuse heat pick-up in the burner zone[6]. Such burner configurations are anticipated to render the furnace walls more tolerant both to burning the indigenous high chlorine coals and aggressive flame derived sulphur species associate with all except the very low sulphur fuels. However, the acquisition of furnace wall thickness data continues at overhauls, albeit less comprehensive than pre-privatisation, to realise any detrimental changes arising from changes in fuel or combustion parameters.

On-Load Waterside Corrosion

Successor companies have embraced and continued the operational practices established under the CEGB towards managing boiler water chemistry within tightly defined limits to mitigate the propensity for on-load corrosion. However, the shift towards greater cyclic operation increased the propensity for condenser leaks, the resultant contaminant ingress causing marked, transient deviations in water chemistry with the potential to initiate and develop on-load corrosion in those tubes displaying excessively thick waterside scales.

The bore scales developed on furnace wall tubes typically comprise both in-situ grown and deposited iron oxides[3]. Boiler start-ups disturb spalled and accumulated oxide debris resident in the larger vessels of the feedwater circuit, such as the deaerator storage tank. This debris is subsequently carried over into the boiler circuit where it subsequently deposits preferentially on the bore of tubes in high heat flux zones of the combustion chamber and at flow disturbances, such as the bends which form the furnace nose. The increased frequency of boiler starts has, therefore, greatly enhanced the rate of waterside scale build-up. To alleviate this threat, tube samples have been routinely taken from known high heat flux areas to monitor waterside scale development. A chemical clean is advised where the oxide thickness exceeds a nominal threshold of 2mils (50μm), which for most boilers has been required on a 4-yearly cycle. Significantly, the relatively few failure incidents have arisen on those boilers where this threshold has been relaxed. Despite the strong commercial pressures to reduce maintenance budgets, the expense of regular chemical cleans remains highly cost effective against the prohibitive expenditure associated with the recovery of a boiler damaged by on-load corrosion.

Overheating

Metallurgical analysis of strategically taken tube samples has traditionally provided the foundation for determining the residual creep-life of tubing in both the penthouse and gas pass to anticipate, and budget for, future maintenance activity. This approach proved effective in managing the threat and maintaining the failure incidence at relatively low levels until the mid-1990s, when pendant stages towards the front of the boiler at some stations experienced a series of premature creep failures.

A detailed study revealed that tubing in the outlet section of these stages was being subjected to transient temperatures in excess of 1200F (650°C) during start-up, thermal extremes linked to uneven gas flows and heat-flux across the boiler width, aggravated by pendant design features[7]. Whilst such transient extremes had limited impact on tube life under predominantly base-load operation, the transition to a flexible operating regime had reduced tube creep-life by approximately 25,000 hours from the anticipated figure. Subsequent plant trials explored the impact of initial firing rate, the pattern of oil and coal burners employed, the timing and duration of deploying various drains in the superheater circuit and reducing water-logging in the superheat stages on achieving balanced metal temperatures. The improvements achieved by progressively refining the hot start procedure were marked; tube metal temperatures remained below 1100F (600°C) for the duration whilst start-up times, from fans in service to unit synchronisation, were reduced from typically 85 minutes to 75 minutes. Procedural improvements from these trials were subsequently adopted by other plant to similar effect and extending tube life.

Since the mid-1990s, more comprehensive condition assessments of creep susceptible stages have been made possible through the development of ultrasonic NDE techniques for the measurement of steamside oxides. This procedure is described in more detail in a companion paper, with reference to the potential limitations of the technique[8].

Post-1990, T91 has been used almost exclusively where extensive penthouse replacements are warranted in the final stages of superheater and reheater circuits. The material was originally developed as a ferritic material with good, high-temperature mechanical properties for nuclear steam generators before being adopted by conventional plant designers. The steel's superior creep properties relative to the T22 grade it replaced has enabled thinner walled tubing to be employed, affording much greater flexibility under cyclic operation. However, the long-term integrity of what should have been 'fit-and-forget' solutions has been compromised on a few boilers by poor design and/or non-compliance with approved procedures for joining and manipulation of the tube, echoing problems with other novel materials.

Liquid Coal Ash Corrosion

The chemistry of indigenous fuels has meant that high-temperature stages have almost invariably been subject to excessive fireside corrosion rates (>8mils/year (>25nm/hr)) since the advent of plant achieving final steam temperatures approaching 1060F (570°C) in the mid-1950s. Stations have effectively managed this integrity threat through routine thickness surveys and the installation of

T316/T321/T347 stainless steel tubing in the final and penultimate stages of superheat and reheat. However, where wastage has precipitated failures after less than 35,000 hours service, the application of more corrosion resistant T310 alloy, in a composite tube form with an E1250 core, has been warranted[5]. Since the late 1990s, the favoured tubing material has been HR3C, an alloy that exploits the excellent high temperature corrosion performance of T310 but exhibits markedly superior creep properties, courtesy of controlled heat treatment and the addition of niobium and nitrogen, at only a modest cost premium relative to the 18%Cr11%Ni alloys.

Despite the potential to impact upon wastage rates, the pattern of coal ash corrosion failures has remained relatively independent of regime changes. This in part derives from the continued practice of policing the failure threat through selective insert work, guided by thickness surveys, before seeking an economic balance between failure incidence and deferred stage replacement. However, the effects of these changes have also tended to negate each other. Since the arrival of low NO_x burner technology in the late 1980s, metallurgical analysis of stainless steel tubing has invariably detected a uniform carburised layer over the radiant crown up to 4mils (100μm) deep[9]. This is believed to compromise the corrosion performance of the steel by 'tying-up' the free chromium normally available to endow protection. However, the actual wastage rates in the pendant stages have remained constant or decreased as the relative proportion of more benign imported coals burnt has increased.

Stress Corrosion Cracking

The rapid emergence of gas fired generation during the early/mid-1990s brought into doubt the economic viability of the large coal fired boilers; some were removed from service whilst others were temporarily retired, not always with consideration to chemical preservation of the boiler circuit.

Subsequent restructuring of the industry when gas prices increased brought about a programme of selective re-commissioning of the more commercially favourable units in the late 1990s. However, shortly after return to service, a series of tube leaks at the chevron bottom bend were reported in stainless steel pendant tubing on one boiler, subsequently diagnosed as stress corrosion cracking (SCC) – essentially an off-load, aqueous damage mechanism. During the period prior to retirement, operation at temperature had caused precipitation of chromium carbide at the austenite grain boundaries, causing chromium depletion of the adjacent microstructure structure. This 'sensitisation' of the steel rendered the tubing vulnerable to SCC by trace concentration of species present in residual condensate collected at the pendant bottom. With limited confidence in detecting the fine, internal cracking, wholesale replacement of the chevron bottoms was ultimately implemented to address the failure threat.

THE FUTURE

Gas-fired plant is anticipated to remain dominant into the second decade of the 21st century towards ensuring compliance with increasingly stringent environmental legislation, thereby driving the ageing coal-fired plant into obsolescence or more extreme operating practices by 2008, when the Large Combustion Plant Directive (LCPD) comes into force. However, should gas prices climb to prohibitive levels and/or issues arise related to security of supply, operation of the existing coal-fired plant may extend beyond current expectations, courtesy of FGD and other retrofit environmental technology to effect NO_x reduction and carbon sequestration, should it become viable.

In the interim, the merits of CO_2 neutral fuels are being explored. Particular emphasis has been given to biomass fuels, co-fired at concentrations up to 10%, the diverse range of potential fuels including milled palm nuts (PKE), wood pellets, shea nuts, maize corn cobs, olive cake, cereal co-product (straw). Whilst provisional studies employing the combustion test facility at Power Technology have found most of these fuels to be corrosion neutral, further work is required to confirm whether disturbing indications of greatly enhanced corrosion on austenitic stainless tubing extends to longer term usage. Site surveys after extended operation with these fuels have also suggested that the boilers are running cleaner, with potential implications for abrasion of upper and lower slopes in addition to sootblower erosion if cleaning

frequencies are not adjusted accordingly. The potential for a higher dust burden may also exacerbate the propensity for fly-ash erosion in the convective pass.

SUMMARY

Deregulation transformed the operational landscape for the large coal-fired boilers in the UK. Despite the potential for these regime changes to greatly impact upon commercial availability, Station engineers have been effective in managing the tube failure problem, addressing those mechanisms responsible for the greatest availability losses to realise the greatest returns on their maintenance budgets.

A transition to greater cyclic operation has enhanced the propensity for fatigue related failures, particularly corrosion fatigue damage in natural circulation boilers, with a distinct bias to the evaporator circuit. Whilst flexible operation has also had the potential to promote on-load corrosion damage, this has generally been effectively managed through routine condition monitoring at overhauls. Condition monitoring activity has also been effective in maintaining a low incidence of corrosion and erosion failures, whilst critical review of start-up procedures has moderated the impact of inherent thermal excursions affecting certain pendant stages on boiler start-up.

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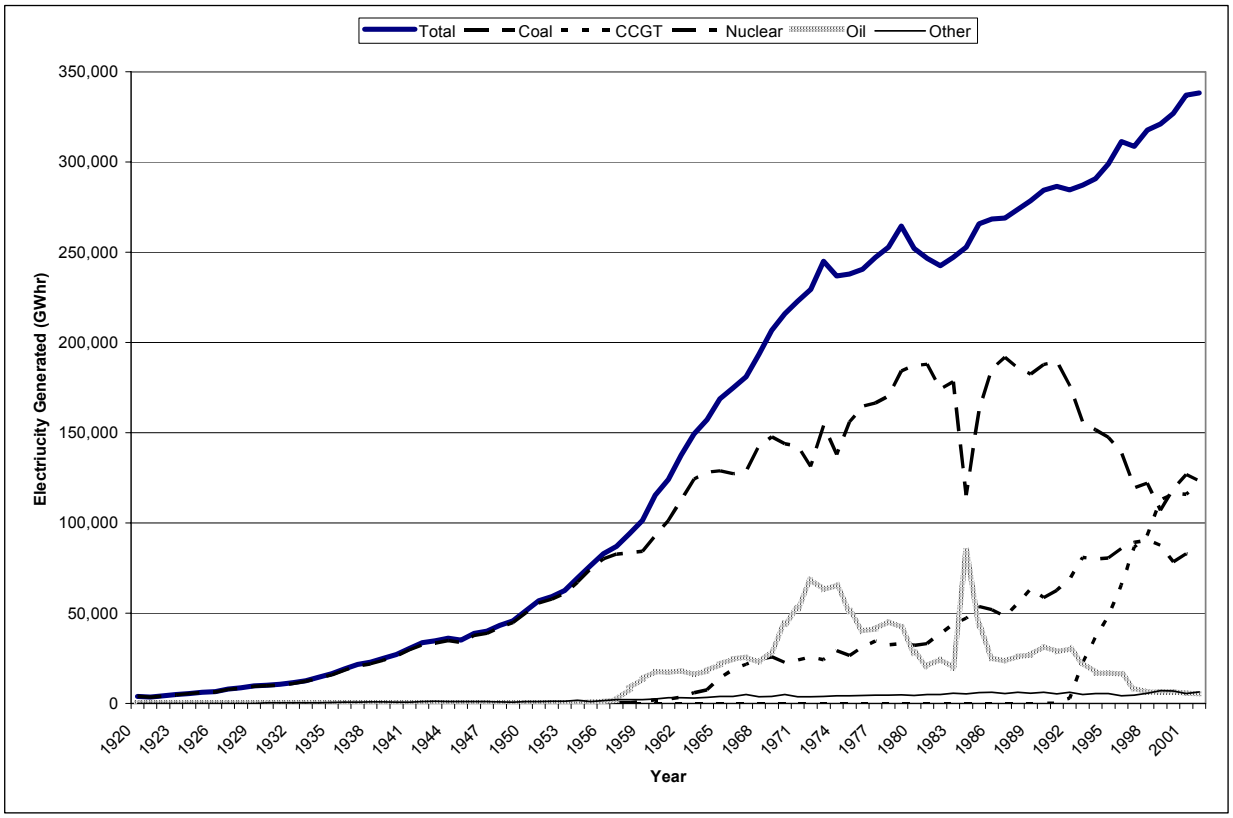

Figure 1; Historic Profile of UK Electricity Generation by Fuel Type

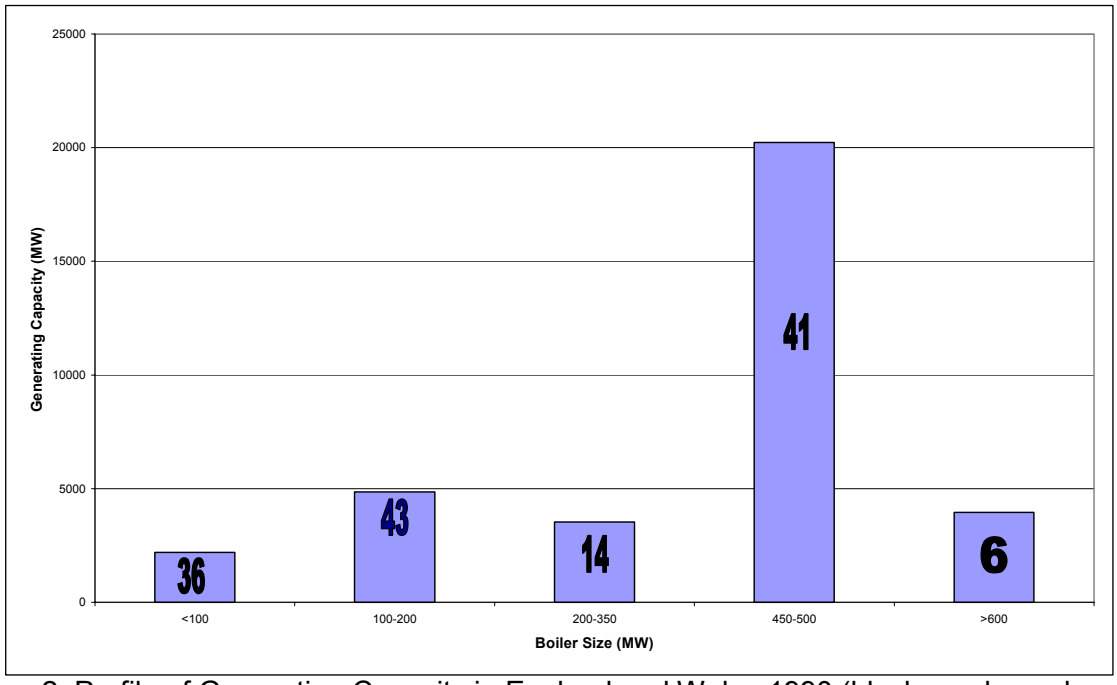

Figure 2; Profile of Generating Capacity in England and Wales 1990 (block numbers show number of boilers in group)

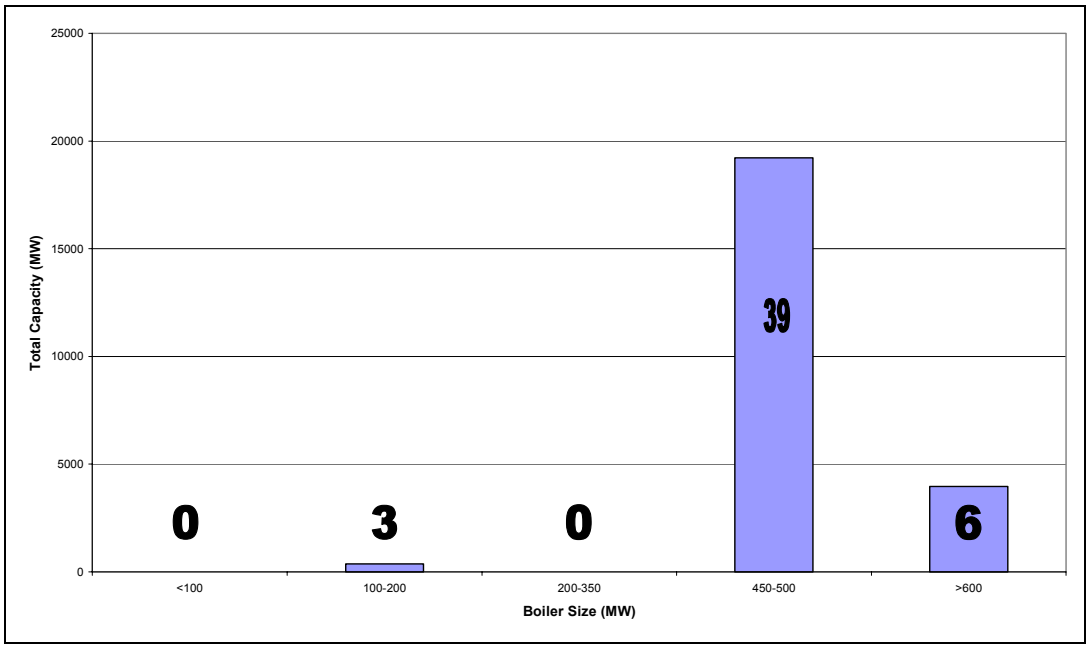

Figure 3; Profile of Generating Capacity in England and Wales in 2000 (block numbers show number of boilers in group)

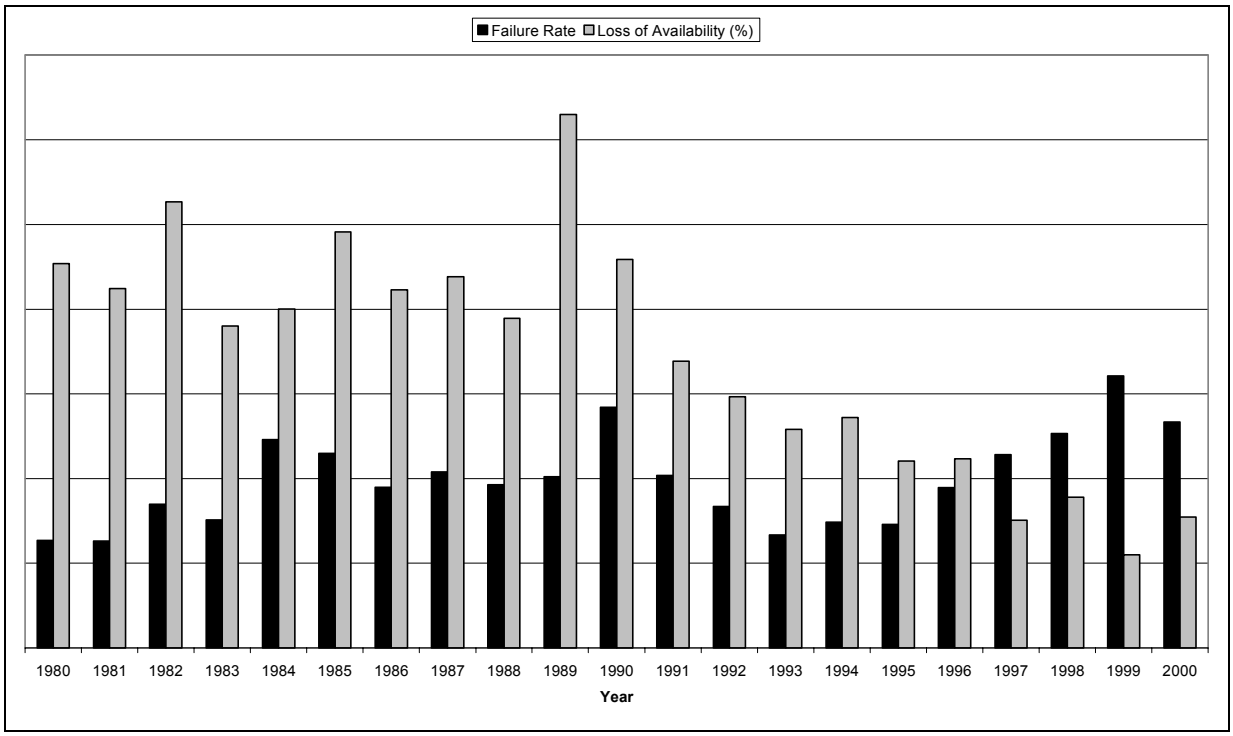

Figure 4; Pre and Post Privatisation Tube Failure Rates and Availability Loss Deriving from such Incidents

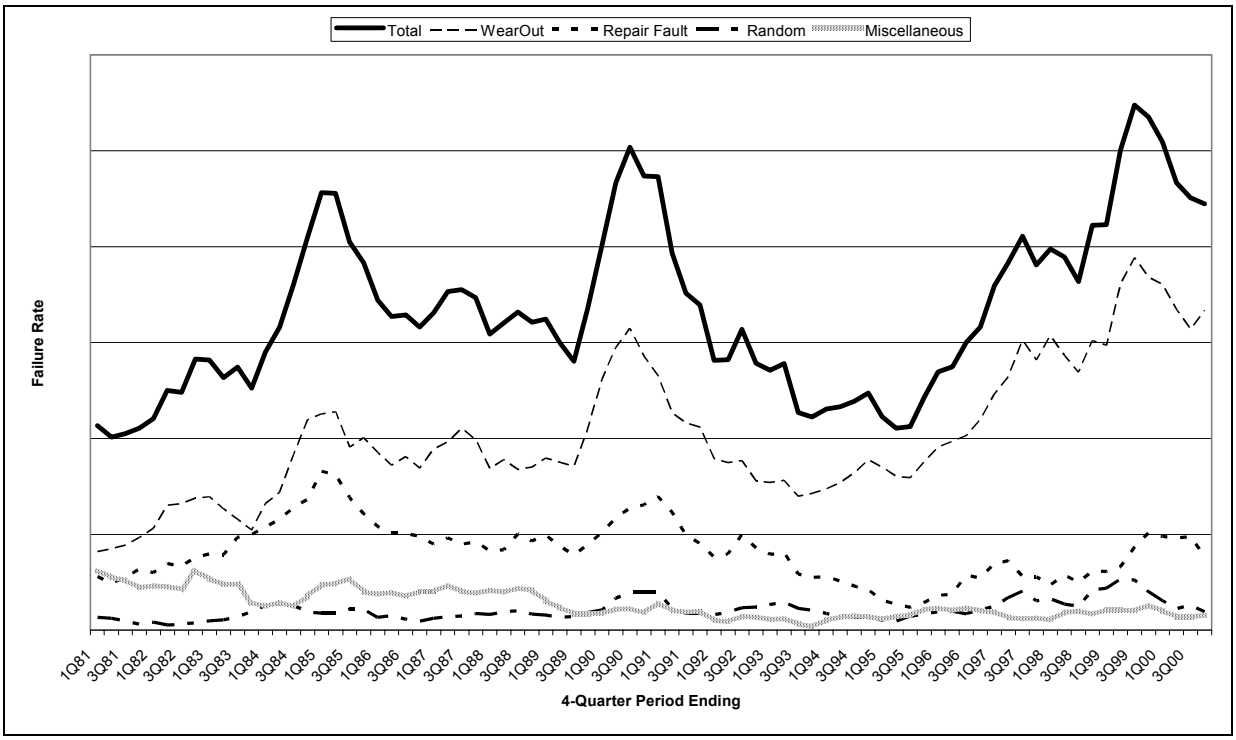

Figure 5; Pattern of Boiler Tube Failures by Statistical Grouping

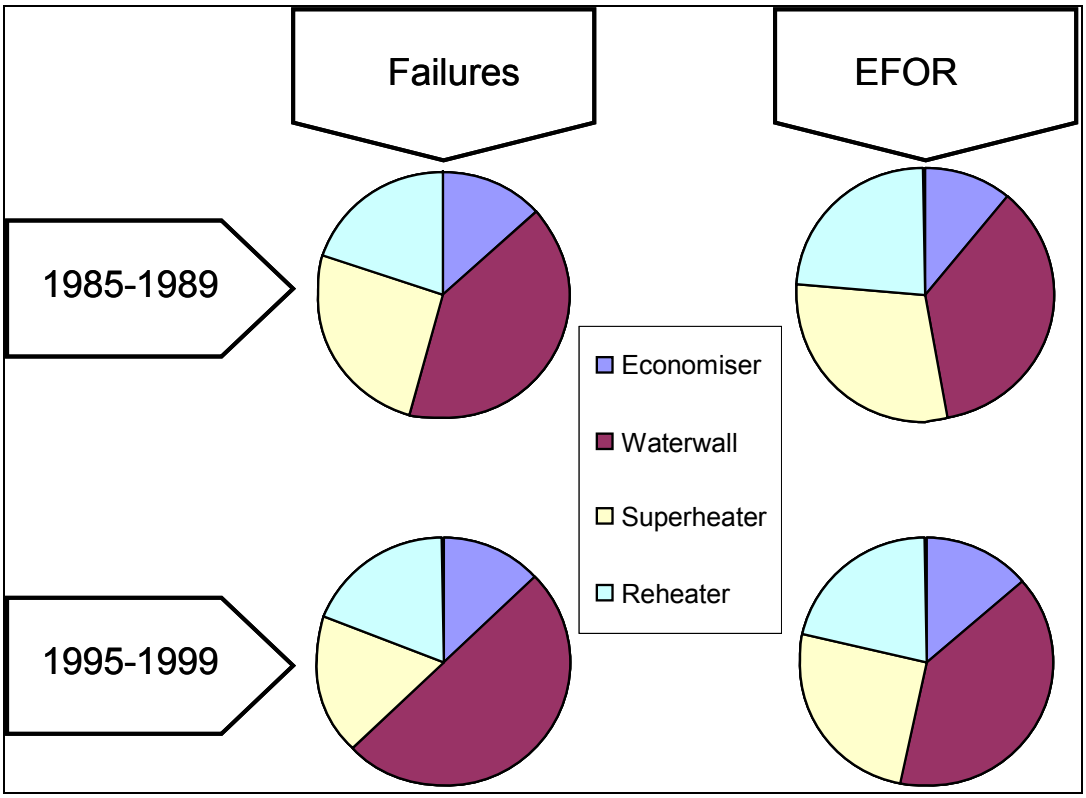

Figure 6; Pattern of Failures by Boiler Circuit and Relative Impact on total EFOR Pre and Post Privatisation

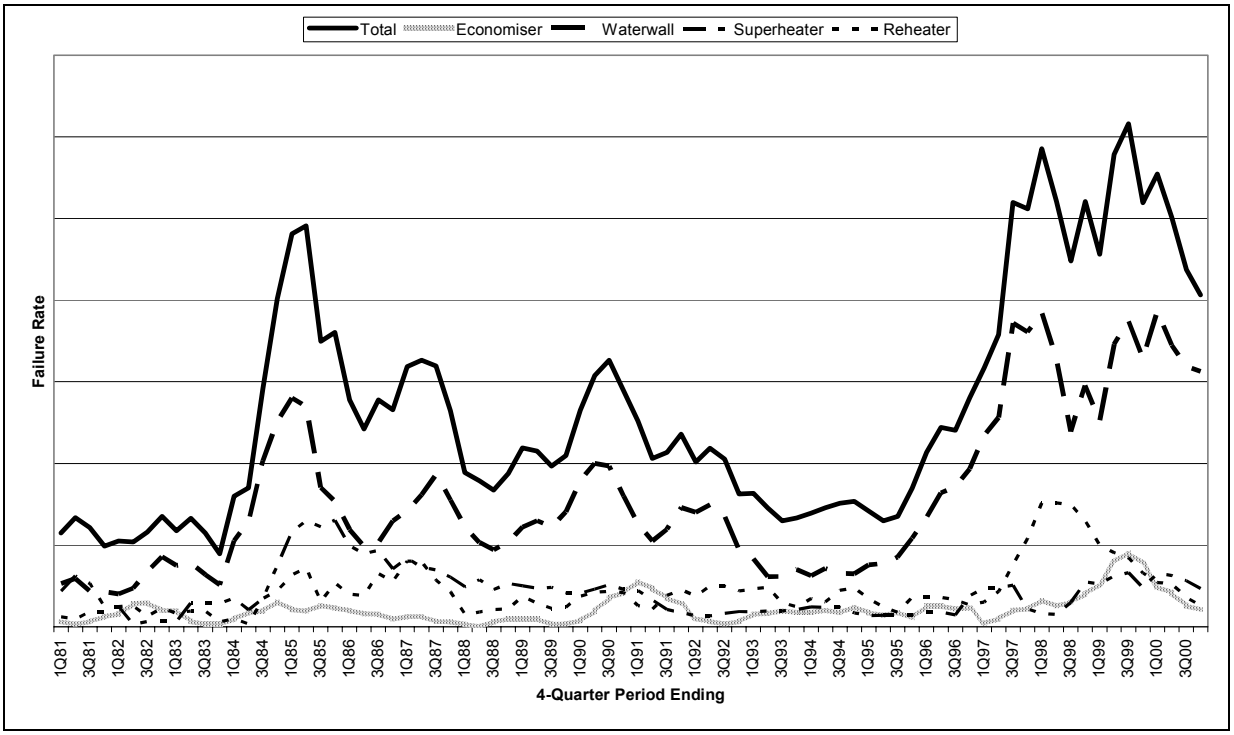

Figure 7; Pattern of Fatigue Failures by Boiler Circuit

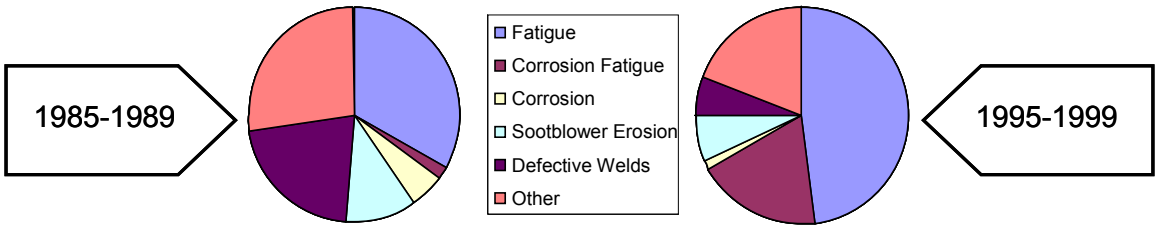

Figure 8; Cause of Failures in the Evaporator Circuit Pre and Post Privatisation

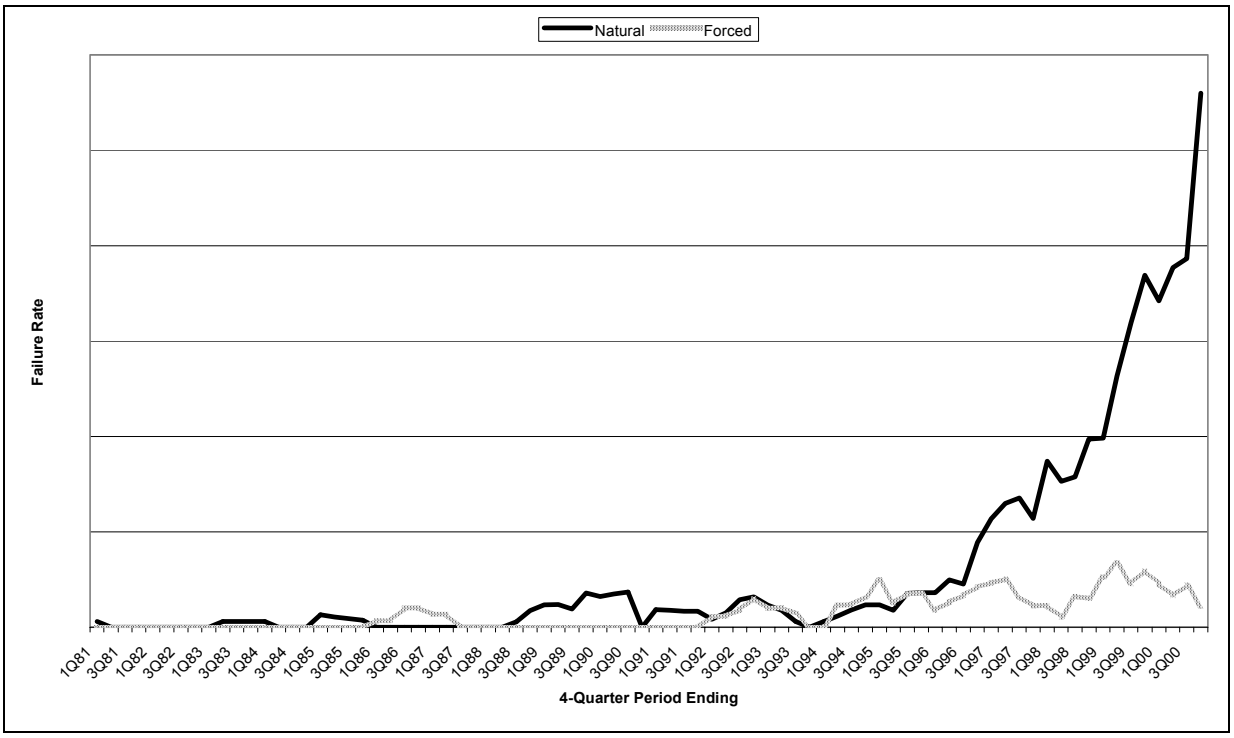

Figure 9; Pattern of Corrosion Fatigue Failures in the Evaporator Circuit for Natural and Forced/Assisted Circulation Boilers

THE BOILER LIFE MANAGEMENT (BLM) MODEL IN THE BELGIUM POWER INDUSTRY - USING RESIDUAL LIFE CALCULATIONS IN A FLEXIBLE WAY

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ABSTRACT

The life extension for boiler parts of power plants is the day of today in an open market a more strategically approach than the last decade. Better boiler assets can be achieved by applying a boiler life management model (BLM).

This model is built on 3 modules. The first module contains the boiler inspection plan philosophy where guidelines describe the inspection frequency and recommended inspection tools for different failure mechanisms in function of the present degradation & operating hours. In the second module you can find different mathematical calculation tools applied for the life consumption assessment. And finally we have the risk assessment module where business costs due to failure can be evaluated and compared to costs for risk reduction.

This paper illustrates the implementation of the BLM model applied by Laborelec for the Belgian Power generator Electrabel. The contents of each module will be explored with focussing on the module of the life consumption assessment. This module (mainly based on corrosion, creep and thermal fatigue principals) has a multi-level approach where the final scientific approach is a mix of design, operation & maintenance history in combination with quantified material characteristics.

The implementation of this BLM model results in an economical optimised boiler inspection and maintenance plan. The inspection plan describes the inspection frequency necessary to follow up the degradation for each component. The maintenance plan gives an investment overview where the cost for replacement of boiler parts is exactly identified in function of operating time.

INTRODUCTION

Industrial boilers have a thin line between gain and loss. On the one hand they can work nearly continuously, on the other hand, their investment cost is high and the loss of production because of an unpredicted failure can be extremely unpleasant. The calculation of the residual life is a handy instrument to work out an adequate inspection and maintenance plan for boilers. However, until now the necessary flexibility was missing. With the boiler life management of Laborelec, plant managers can adapt the parameters themselves to optimise the operating and the financial planning of the boilers. The result is a strong partnership, between Laborelec and the customer, that gets maximum gain out of the boilers in the way *the customer* wants it.

WHAT'S SO FLEXIBLE ABOUT BLM

A little story to begin with. As a regular user of the train, I am very pleased with the website of the Belgian National Railways. In the past, asking for information in a railroad station could spoil my entire day. Once I wanted to travel from Brussels to Nancy, France by train. The man behind the counter wanted to know when exactly I wished to leave, so I gave him the desired date and time of departure. He started looking in his books and a quarter of an hour later he wrote down the railroad lines and the hours of the trains.

- "And what if I want to leave earlier?"

- "How much earlier?"

- "I don't know, let's say one train earlier."

The man huddled over his books again, after which he filled in a new form.

- "And what if I want to leave later?"

- "But sir, do you want to leave earlier or later?"

He got irritated.

- "You've got to know what you want."

- "I don't know yet what I want."

- "So why are you here?"

Now I got irritated too.

- “How can I know what I want, when I don’t know the possibilities! Please give me the railroad lines in case I want to leave on a later train!”

And again he browsed through his books with timetables. Behind me, there was a row of people giving me angry looks. Each minute, I grew more agitated. I still had so many questions – what if I stay overnight in Luxemburg? What if I go via Paris instead of Luxemburg? – but to avoid an outburst from the people waiting behind me, the man behind the counter, and myself, I thanked the employee and disappeared.

With the residual life calculations of boilers, there was a similar problem. The plant managers wanted to know the residual life for working out a good inspection and maintenance plan. For those residual life calculations, they had to give the operational conditions. Those conditions, however, represent a function of the financial planning of the boiler, and to make an accurate financial planning, it was necessary to know the residual life!

Today, the user of the Belgian railways can look up all information he needs on a flexible and user friendly website. In essence that’s the kind of tool Laborelec is offering for residual life time calculations. The preparations, the measures with NDO techniques, the calculations and the analysis of the results, are all still done by Laborelec. But with these results, the customer can simulate different situations, depending on the operational conditions that he is choosing, without having to go back to Laborelec for starting the calculation process all over. Within the open European market, such a tool is very much welcome. It has become strategically important to minimize the cost and risk and at the same time to remain flexible in operating the boiler. So let us have a detailed look at this ‘boiler management system’.

BLM IN SHORT

The boiler life management model (BLM-model) of Laborelec has been developed for medium to large boilers - normal fossil boilers as well as Heat Recovery Steam Generators (HRSG). It results in an optimised inspection and maintenance plan for the boiler. The inspection plan describes the inspection frequencies necessary to follow up the degradation of each component. The maintenance plan gives an overview of the predicted investments in the replacement of boiler parts in the course of time.

This inspection and maintenance plan is based upon the plant’s actual status and how much of its service life has been expired. It requires a correct drawing of the correlation between the operational load and the actual status. This is done by a combination of analytical considerations, calculation methods and relevant non-destructive and destructive tests.

The first step in the BLM-system is the determination of the critical components. Next, those critical components are inspected with a specific testing technology. Out of the results of this first inspection, an inspection plan for the future is derived and the residual life of the components is calculated. With a special software module, the customer can simulate how changes in the operating conditions influence this inspection plan and residual life calculation. In this way he can optimise the operation conditions taking into account other than technical arguments as well, for instance the financial planning. After each following inspection, the inspection plan is fine-tuned, the residual life calculations are redone, and the customer can make a new simulation.

Soon Laborelec will also release a financial module. This software will compare the gain of the boiler with the investment and maintenance cost in the course of time, in order to calculate the optimal time for changing the component.

DETERMINATION OF THE CRITICAL COMPONENTS

The first question that rises is 'what kind of damage or material failures have a significant chance to occur, and in which components?'. In general, three possible degradation mechanisms are taken into account: corrosion, creep and thermal fatigue. Only when the boiler is operating under extreme conditions, other failure mechanisms might be added to this list. With the design data and a first quick scan of the boiler, the Laborelec experts can tell in which components there is a risk for one of these three failure mechanisms. They use guidelines based on 30 years of field experience with similar equipment. The main criteria used are the following:

- Components critical for creep: based on design temperature
- Components critical for thermal fatigue: based on wall thickness
- Components critical for corrosion: based on experience, and, for older boilers, on the loss of wall thickness in function of the time

This first list of critical components with their most critical failure mechanism will be reduced later on.

In the next step, the operating and maintenance history is taken into account, as well as the inspection history (if available). This means:

- The operating history
  - Pressure and temperature during operation
  - Incidents, events of failure and repair statistics
  - Number of starts and stops and the total amount of service hours

- The maintenance history
- Component replacements and repairs
- A review of the component geometry
- The results of former inspections

With this information, a first rough theoretical calculation of the residual life of the critical components is made.

NON-DESTRUCTIVE AND DESTRUCTIVE TESTING

The preceding information makes clear which examinations have to follow to refine this calculation. Following decisions will have to be made:

- Where these extra tests have to be done
- Which techniques will be used

Most of the time, non-destructive inspection techniques will be used. The choice of the specific technique depends on the component, the location on the component, the damage modes that are looked for, and the material that is used. Some of these techniques provide quantified data that can be used in residual life calculations, others only indicate whether there's a defect or not. Examples of techniques are

- taking a replica of the surface to discover cracks
- using ultrasonic sound to measure wall thickness
- using X-rays to look for irregularities

After non-destructive testing, some material properties like creep strength can still be an important source of uncertainty for the calculation of the life expenditure. According to Neubauer and Webel, the creep life consumption is correlated to cavitation. To determine the number and the characteristics of the cavitations, it may be necessary to take specimens of material from the actual components. If so, the sampling has to be done without degrading the component in any way. Various sampling methods are used: boot samples, trepanned, core samples, through wall trepanning, … After the use of some of them, weld repair may be required.

THE RESIDUAL LIFE TIME CALCULATIONS

Based on all the former inspection, design and maintenance data, Laborelec calculates the residual life of the component. This can be done by two different approaches:

- theoretical life time consumption calculations mainly based on the TRD 508 recommendations
- qualitative life time assessment based on the examined metallographic investigations

For both approaches, we use several homemade software tools like:

- software to calculate creep damage out of metallographic examination, and the repercussions on the remaining life
- The software LILCA, for high temperature tube life prediction
- The software THERMSTRESS, for fatigue calculations
- …

The 'trending' failure mechanisms, like uniform corrosion, erosion, creep and fatigue, have changing indicators over time, so their influence on the residual life time calculations and the inspection plan has to be recalculated after each inspection.

THE INSPECTION AND MAINTENANCE PLAN

The residual life and the critical failure mechanisms of all the critical components are the basis for working out an efficient inspection and maintenance plan. The inspection plan gives the necessary inspection intervals of all the critical components, which techniques will be necessary for the inspection, and its cost. The maintenance plan gives the optimal moments and the cost for repairing or replacing components.

For the trending degradation mechanisms, the modelling of the inspection intervals is redone after each inspection. For those degradation mechanisms, the inspection interval is defined as the remaining life time divided by a security factor. Laborelec uses a statistical approach for the erosion and corrosion degradation mechanisms. For creep evaluation we prefer a deterministic approach such as the sudden death risk analysis method. For those calculations of the inspection intervals, we use our homemade software INTERVAL.

SIMULATIONS WITH VARIATION IN THE OPERATING CONDITIONS

Since the operational parameters influence the boiler life time calculations, they consequently have an influence on the inspection and maintenance plan. Laborelec provides their customers with simulation software that calculates this influence. After Laborelec has done the inspection, has calculated the residual life of the components, and has worked out a first inspection plan, the

customer can use the software to look up how changing the operational parameters will change the maintenance and inspection plan. He can input several different sets of parameters without going back to Laborelec for doing the whole inspection and calculation all over. Those simulations, however, are only accurate during a certain period after the complete residual life time calculations. So they don't replace the recalculation of the residual life after each inspection. Nevertheless, this software tool makes the operation of the plant manager a lot more flexible. It allows the plant manager to search for an optimal equilibrium between the operational cost, the operational gain and the maintenance cost.

THE FINANCIAL MODULE

To make the calculation of this financial equilibrium easier, Laborelec will soon release a financial software module. The input of this module is:

- the produced MW at selling price
- the production cost (employees and fuel)

Those are compared throughout time with the maintenance cost, consisting out of:

- the investment of the original boiler
- the investments in repairing or replacing components
- the inspection costs
- the production loss during a stop

The first points (produced MW and production cost) as well as the last (maintenance cost, a function of the residual life) are influenced by the operational parameters. Thus with this software it becomes easier to search for the optimal operational parameters. This software can also lead to the decision to take certain boiler components or the whole boiler out of production before the residual life time is over, because the maintenance cost in the last part would grow to high.

MAINTENANCE IS A FLEXIBLE PARAMETER

The basis of the technology of boilers may be rather old; this doesn't mean that there is no optimisation possible anymore. The Boiler Life Management proves that the maintenance of a boiler should be regarded as a flexible instrument. Punctual calculations of the residual life might be enough for a secure operation during a certain period, it is certainly not enough to optimize the total maintenance of the boiler. To make a real optimization, it is

necessary to plan the inspections in an intelligent way and to refine the calculations regularly. At the same time, the maintenance should be integrated in the operational and financial planning of the boiler and the whole production process. So a close relationship and a constant dialogue between the residual life experts and the operational managers is necessary. At a few customers of Laborelec, the positive results of this way of looking at boiler maintenance are already clearly visible.

LILCA, FOR HIGH TEMPERATURE TUBE LIFE PREDICTION

To perform assessment and determine the remaining life of high temperature boiler tubing, it is necessary to accurately measure the critical tube dimensions and predict the time dependent response of the tube material.

Laborelec measures wall and internal oxide scale thickness to predict the remaining tube life with LILCA (Laborelec Incremental Lifetime Calculation Algorithm) software. Thickness measurements are made using focused UT transducers. Steamside oxide layer thickness measurements allow the evaluation of the average metal temperature of components by using the material oxidation kinetics.

LILCA has the possibility to input external wall loss due to erosion or high temperature corrosion. It contains algorithms that allow the user to make deterministic estimates of tube remaining life.

THERMSTRESS, FOR FATIGUE CALCULATIONS

Fatigue only takes place if the load is alternating. During this load alternation, three types of alternating stresses can be registered:

- mechanical stresses due to change in pressure or to changing system stresses.
- Thermal stresses due to temperature differences through the component wall thickness. These stresses become only significant when the wall thickness is larger than 45 mm.
- Stratification due to temperature differences on two opposite spots on the component.

With the input of the characteristics of the component and the operational history, THERMSTRESS calculates the fatigue and the probability of failure due to fatigue.

ROOT CAUSE ANALYSIS METHODOLOGY APPLIED TO REDUCE BTF AFFECTING A POWER STATION

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Abstract:

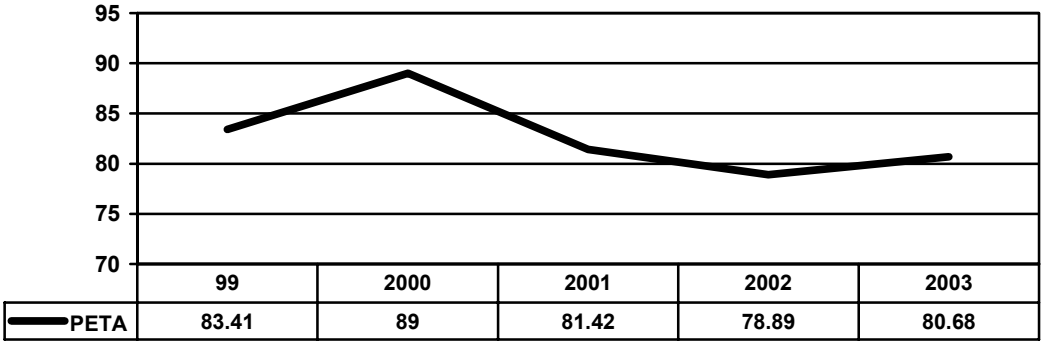
In this work the methodology of Root Cause Analysis (RCA) is presented and applied to analyze the boiler tube failures (BTF) of six units of a thermal power station. The main objective is to identify and prioritize the dominant failure mechanisms, as well as the establishment of the causes that produce them. Arriving at the level of root cause is sought, to finally establish definitive proactive solutions in order to decrease the availability loss. In addition, the methodology is used to clarify some questions on the performance of units, the possible existence of a similar failure pattern in the same ones, as well as the influence that the operation has had with different fuels. Finally, an easily and accessible format is proposed for all the relevant decision making information.

Introduction:

The power station is the property of CFE (42,000 MW) and has six 350 MW units. Design allows burning coal or heavy oil indistinctly, boilers were put in service between 1993 and 1994, they have the same capacity, design and original manufacturer. In recent dates, the high frequency of failures motivated a study to determine their causes. The methodology that was proposed was that of RCA.

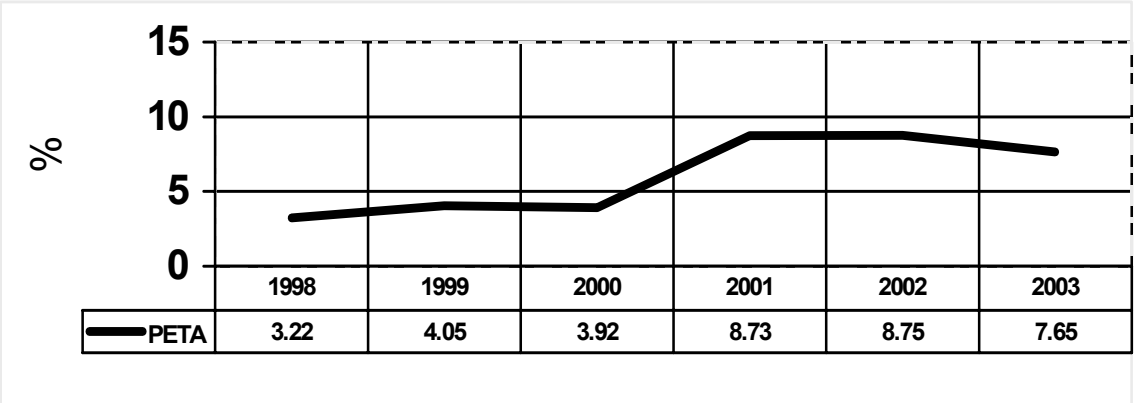
Regarding the Availability Factor of the power station, in 2000 they reached a maximum of 89.0 % and then fell gradually to 78.89% in 2002; finally they showed a slight improvement tendency to 80.68 in 2003 (figure 1).

AVAILABILITY FACTOR %



On the other hand, Equivalent Failure Unavailability Factor of the Station shows the same trend, but this time the striking decrease starting on 2001 is more evident (figure 2). Numbers in figure 2 include all failures and not only those related to BTF.

UNAVAILABILITY FACTOR %



The Root Cause Analysis Methodology.

There are several methods in the market place to conduct root cause analysis (RCA), essentially they are quite similar with slight differences in the way in which they graphically represent the cause and effect relationships. The one used in this work is the one proposed by Robert J. Latino and Kenneth C. Latino and the following is brief description of it.

Modify Failure Modes and Effects Analysis (FMEA): This stage is aimed at identifying the most significant or costly events, in this case in terms of unavailability losses, although the final idea would be to express them in terms of monetary losses. In essence, this is a focusing technique used in order to identify the most important issues. It allows us to have a global look at

the situation, estimate the individual impact of every event on performance and the establishment of priorities of attention or solution. The approach used differs from the traditional FMEA in that the last one incorporates probabilistic calculations to estimate the possible derivations and consequences, requiring of a lot of time, while the modified method only includes historical data.

Information Preservation: This stage is very familiar to the failure analysts. The 5- P´s concept is incorporated in order to preserve and collect the pertinent information related to: Parts (something physical or tangible); Position (Physical position and point in time); People (physical observers or witness that possess the relevant information); Paper (relevant information like specifications, procedures, chemical, metallurgical, NDE, training and financial reports among others); Paradigms (set of rules and patterns that represent the beliefs influencing the decision making process).

Ordering the Analysis Team: In order to review all the information and carry out the RCA process, a team of analysts must be formed. This is particularly important when analyzing the whole performance or failure trends of equipment. It is very important to maintain diversity and synergism, in such a way that experts with complementary skills are included, like metallurgical, mechanical, chemical, maintenance and process engineers. Team member roles and responsibilities and critical success factors have to be defined.

Analysis and Identification of Root Causes: This stage is where all the information is put in order and analyzed with the aim of identifying the three root levels: Physical Roots Causes (to the level of components or tangible elements); Human Root Causes (decision errors of omission or commission) and Latent Root Causes (organizational systems that people use to make decisions like policies, operating and maintenance procedures and purchasing, storage and inventory practices, etc). The Logic Tree is used to organize the information collected and to put it into an understandable and logical format so as to be able to evaluate the diverse hypothesis and the cause and effect relationships.

Communicating Findings and Recommendations: Before writing the final report, recommendations have to be established and discussed and validated by team members. In order to be successful, they have to be directed to eliminate or greatly reduce the impact of the cause through eliminating the recurrence risk. Report including recommendations should be clear, concise, and understandable, attributes of great importance for the acceptance and implementation of the recommendations. Finally, the report is distributed inside the organization to such stations that may have similar equipment and operations and therefore similar problems.

Results Evaluation: The final effort for RCA success is represented by the implementation of recommendations. Unless recommendations are implemented we cannot expect the intended results to be obtained. Next, a measuring system should be put in place, which could be the same as that which identified the deficiency in the first place (mean time between failures, energy loss by BTF, equivalent unavailability factor due to BTF, etc.). Finally it is considered a good practice to make all the people in the organization aware of results and benefits of the RCA and to start the cycle again with the aim to become more proactive and less reactive each time.

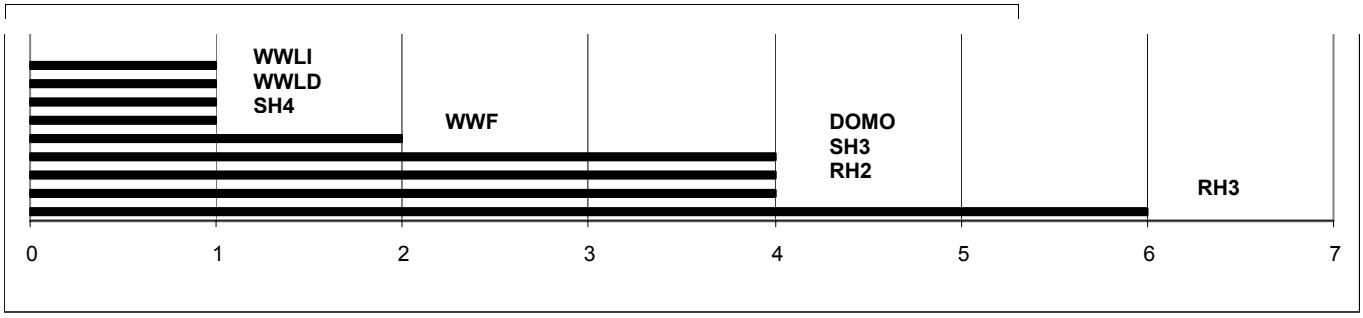
Failure Modes and Effects Analysis: Petacalco Station

By applying the FMEA methodology to each of the six units of the power station, figures 3 to 9 are obtained. Some columns have no information because some of the historical data was not

readily available; nevertheless in this case BTF statistics were sufficient to obtain the whole failure picture.

UNIT 1: Figure 3. EXTENDED

Subsystem	Event	Failure Modes	Frequency	Lost Energy	Materials & Labor	Total Impact	%
Boiler	Drum	BTF	4				
Boiler	WWFRONT	welding Flaw	2				
Boiler	WWPOST						
Boiler	WWLEFT	Welding Flaw	1				
Boiler	WWRIGHT	Welding flaw	1				
Boiler	SH1						
Boiler	SH2						
Boiler	SH3	BTF	4				
Boiler	SH4	Welding Flaw	1				
Boiler	RH1						
Boiler	RH2	BTF	4				
Boiler	RH3	BTF	6				
Boiler	ECO SUP						
Boiler	ECO INF						
Boiler	Burner Crner	welding Flaw	1				
TOTAL			24				



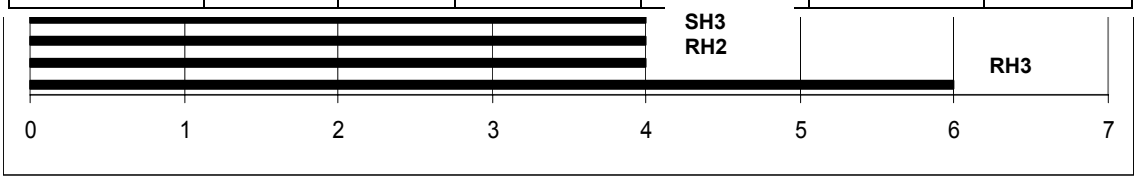
As can be noticed, this table is already focused toward BTF. In the Event column, it presents the sections in the boiler where the failure could be located and the Mode column specifies the failed component itself, subsequently the frequency, the lost energy and the associated costs are registered. Finally, a graph is built in order to have a global look at the whole situation and at the same time to allow the identification of the most significant events.

Next figure presents the same information for boiler 1, but this time only the most significant events are reported.

UNIT 1: Figure 4.

U 1

Subsystem	Event	Failure Mode	Frequency	Lost Energy	Materials & Labor	Total Impact
Boiler	SH3	BTF	4			
Boiler	RH2	BTF	4			
Boiler	RH3	BTF	6			
TOTAL						

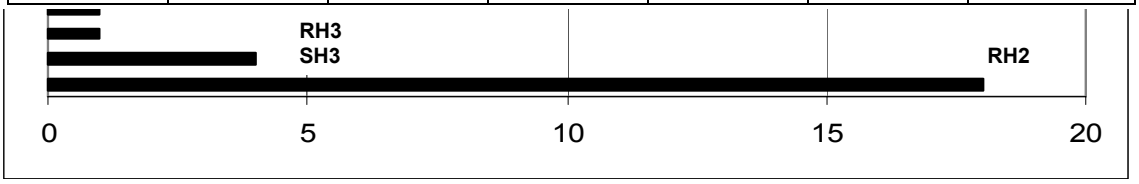


As it was already shown in the figure 3, boiler 1 has had a slightly higher failure incidence in RH3, followed by SH3 and RH2, but there is not a well-defined pattern.

UNIT 2: Figure 5.

U 2

Subsystem	Event	Failure Mode	Frequency	Lost Energy	Materials & Labor	Total Impact
Boiler	SH3	BTF	4			
Boiler	RH2	BTF	18			
Boiler	RH3	BTF	1			
TOTAL						

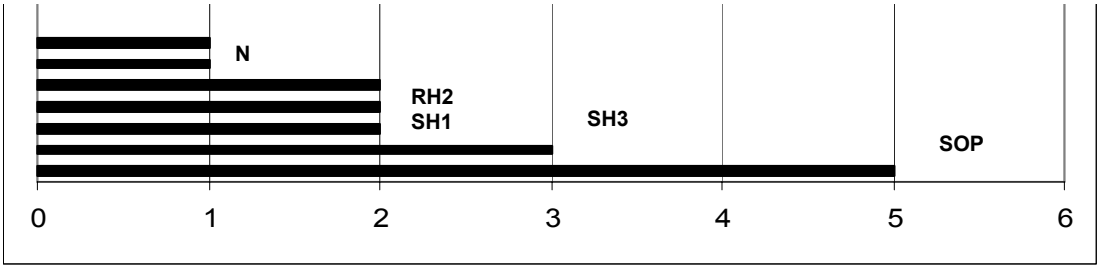


For Boiler 2, it comes off clearly that most of the failure events are located in RH2 and this location is where attention must be focused on.

UNIT 3: Figure 6.

U 3

Subsystem	Event	Failure Mode	Frequency	Lost Energy	Materials & Labor	Total Impact
Boiler	SH1	BTF	2			
Boiler	SH3	BTF	3			
Boiler	RH2	BTF	2			
Boiler	Nose	BTF	1			
Boiler	SOP/PA	Soot Blower	5			
TOTAL						

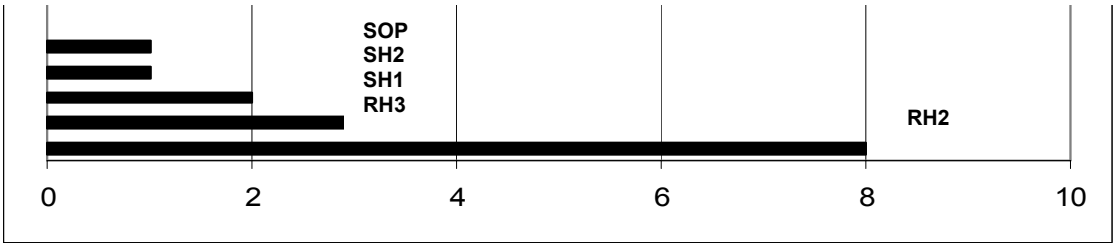


For Boiler 3 most failures reported were located at the soot blowers, apart from this, few failures were distributed in SH1, SH3 and RH2.

UNIT 4: Figure 7.

U 4

Subsystem	Event	Failure Mode	Frequency	Lost Energy	Materials & Labor	Total Impact
Boiler	SH1	BTF	2			
Boiler	SH2	BTF	1			
Boiler	RH2	BTF	8			
Boiler	RH3	BTF	3			
Boiler	SOP/PA	Soot Blower	1			
TOTAL						

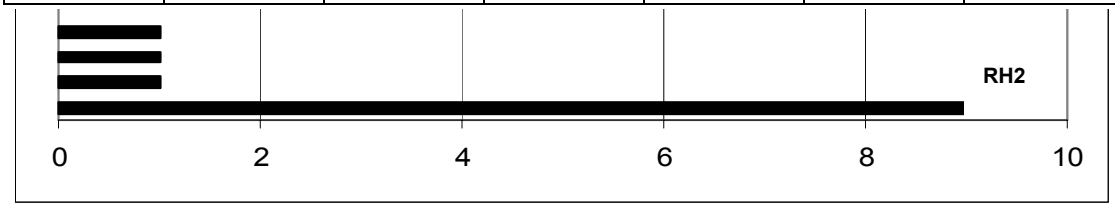


In the case of the Boiler 4, most failures were located at RH2, a smaller incidence was observed in SH1 and RH3. Apparently, this boiler shows discretely the same failure pattern as boiler 2.

UNIT 5: Figure 8.

U 5

Subsystem	Event	Failure Mode	Frequency	Lost Energy	Materials & Labor	Total Impact
Boiler	RH2	BTF	9			
TOTAL						

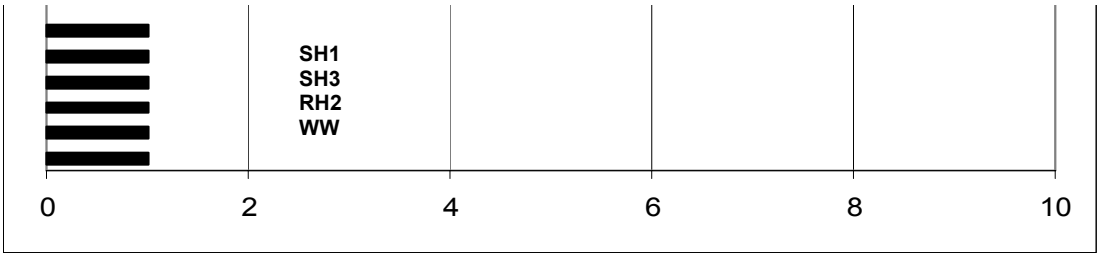


In Boiler 5 is clearly evident that failure events have been impacting on RH2.

UNIT 6: Figure 9.

U 6

Subsystem	Event	Failure Mode	Frequency	Lost Energy	Materials & Labor	Total Impact
Boiler	SH1	BTF	1			
Boiler	SH3	BTF	1			
Boiler	RH2	BTF	1			
Boiler	SOP/PA	Soot Blower	1			
Boiler	WW	BTF	1			
TOTAL						

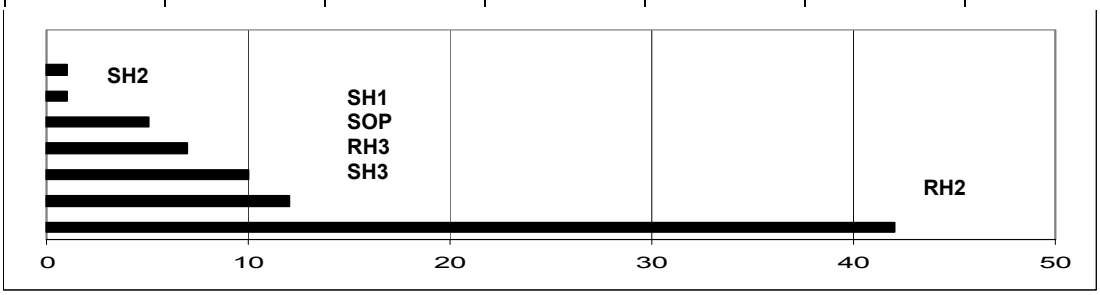


Regarding Boiler 6, there is no failure trend because this unit has remained in reserve during some periods since it was commissioned.

STATION TOTAL: Figure 10 (U1 A U6).

ALL UNITS

Subsistem	Event	Failure Mode	Frecuency	Lost Energy	Materials & Labor	Total Impact
Boiler	SH1	BTF	5			
Boiler	SH2	BTF	1			
Boiler	SH3	BTF	12			
Boiler	RH2	BTF	42			
Boiler	RH3	BTF	10			
Boiler	Nose	Attachment	1			
Boiler	SOP/PA	Soot blower	7			
TOTAL						



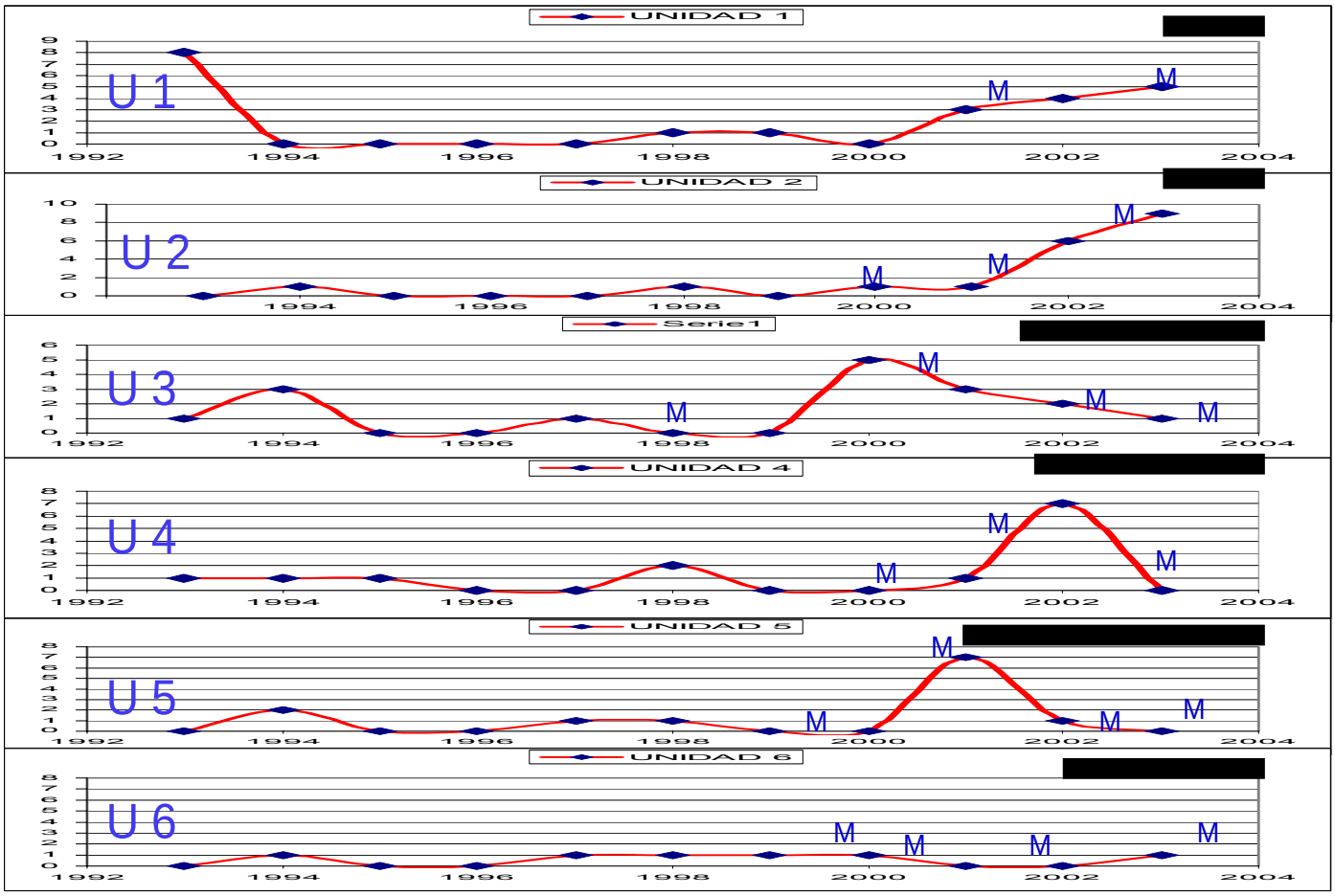
A global analysis of the 6 Boilers together, shows overwhelmingly that the most significant problem of the station is represented by RH2 failures, following a smaller proportion SH3 and RH3, and a still smaller proportion in SH1.

From this analysis it is evident that the main priority is represented by the identification of RH2 failure root causes and in second place SH1 and RH3 root causes. The possible interrelations should be investigated as well.

Failure Performance as a Function of the Incidence, the Maintenance and the Fuel:

AMEF results were used to try to answer the question regarding a possible similar performance of the boilers according to their failure incidence, so failure distribution through the years was calculated and the figure 11 was obtained. As it was mentioned early, boilers 2 and 4 apparently had shown a similar pattern, but this complementary figure clarifies that this is not the case.

FIGURE 11



As can be appreciated, unit 1 has shown similar behavior to the one denominated "bathtub" type, with a high index of failures right after commissioning (that was corrected for the following units) and with a growing deterioration after a certain period, in this case eight years. On the other hand, unit 2 presents similar behavior only without the initial early failures. In both cases the scope of maintenance activities (M) was not able to reduce the failure incidence.

The second group is formed by units 3, 4 and 5, which showed moderated deterioration in the first years, later on this condition was corrected by the maintenance activities. Finally, they show the beginning of a deterioration curve between the eighth and the ninth years, which was also reverted with a more intensive maintenance activity.

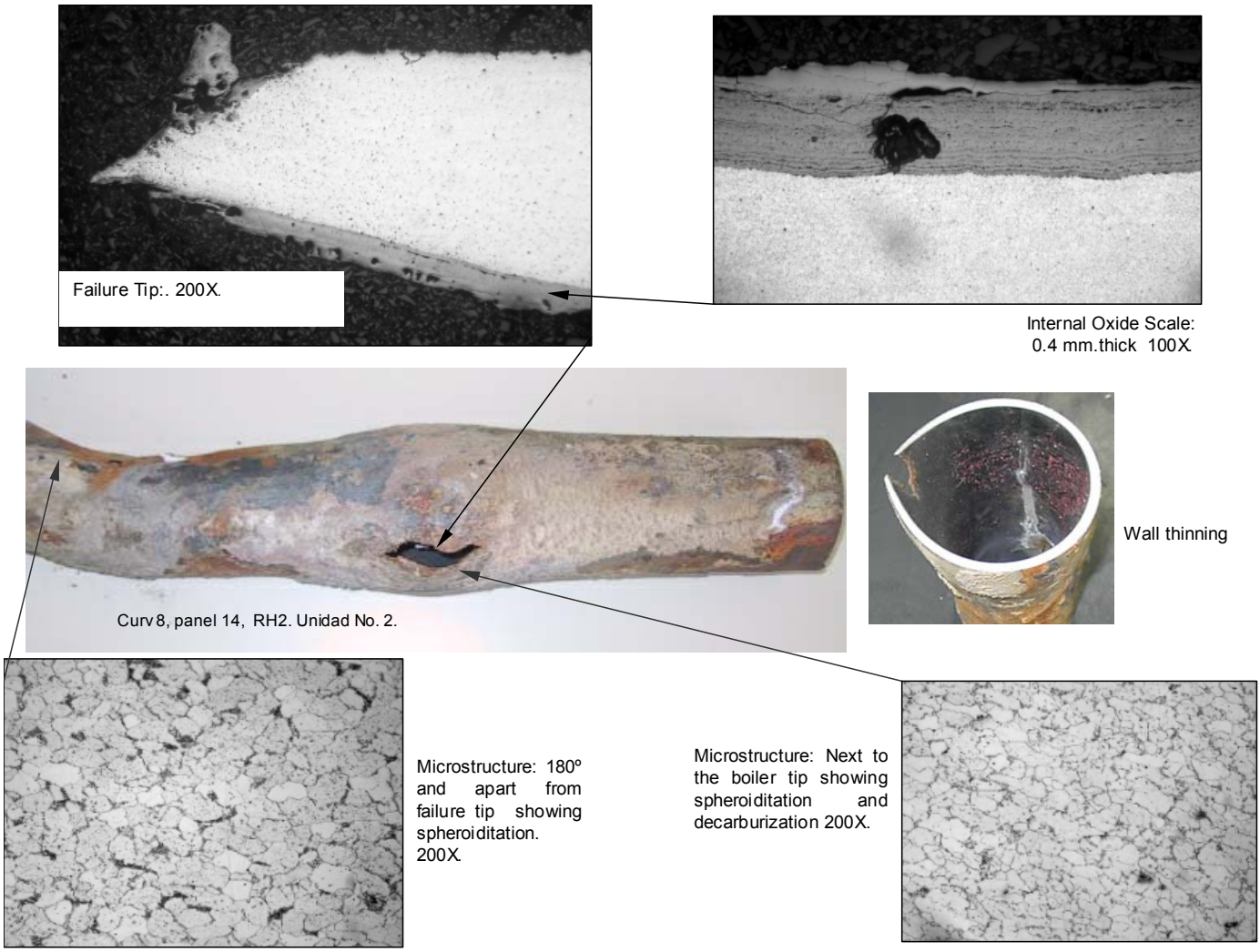
Finally, it is unit 6, which does not show any deterioration due to failure incidence and that is because it has remained in reserve during lingering periods.

The same figure allows us to answer the other great question regarding the influence of fuel on the failure rate. The black fringe, up to the right of each boiler curve indicates the beginning of operation with coal. As it is evident, the failure incidence drastically diminished when the operation with coal began, which demonstrates that the most of the deterioration happened during the operation with heavy oil and seemingly failure diminished notably during the operation with coal.

Studies Results:

Failure Analysis and Metallography. - Different tubes from the failed elements were analyzed, including samples from SH3, RH2 and RH3, the failure mechanism was always associated to high temperature exposition, final result was long term overheating and hot corrosion due to complex compounds, such as sodium vanadyl vanadate formed from heavy oil ash.

The dominant appearance of the failed tubes is presented in figure 12. Macroscopic and metallographic features confirm what was stated in the previous paragraph.



On the other hand, In-Situ metallography was carried out. The areas exposed to higher temperature were determined in order to establish future tube substitutions and the degradation process rate. The latter by means of future inspection events and taking into account that if not validated with tube samples, replica technique would be mainly representative of surface conditions. Figure 13 reflects the current conditions, after some tube substitutions in diverse

sections and periods. (White corresponds to incipient affectation, gray to moderate and black to advanced affectation). As can be noticed, the areas with higher affectation correspond to SH4, RH2 and RH3 in general, and more specifically to RH2 and RH3 for the Unit 1; SH4 and RH3 for the Unit 2; SH4 for the U3; RH2 and RH3 for the Unit 5 and the SH4 for the Unit 6. RH3 deterioration was in part attributed steam flow disturbances caused by RH2 failures.

	SH1	SH2	SH3	SH4	RH1	RH2	RH3	ECO.S	ECO.E
U 1	N	N	N	M	M	A	A	N	N
U 2	N	M	M	A	M	N*	A	N	N
U 3	N	N	N	A	M	M	M	M	M
U 4									
U 5	N	N	N	M	M	A	A	N	N
U 6	N	N	N	A	M	M	M	N	N

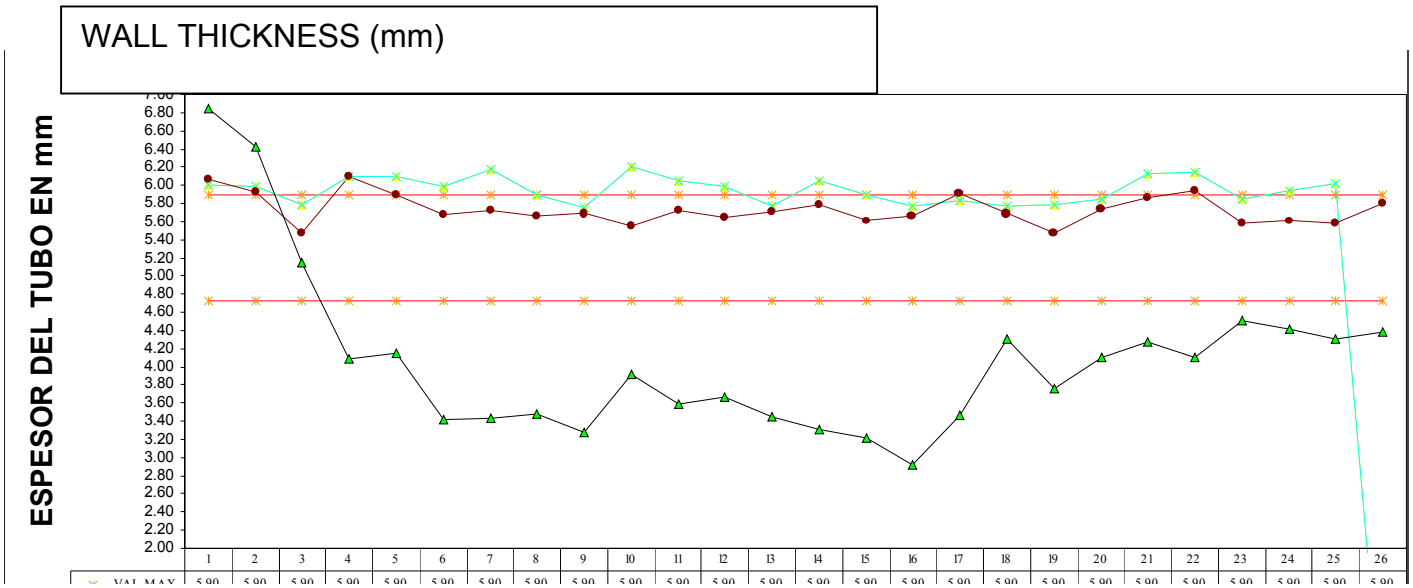
- New Bank

Internal Oxide Scale Evaluation. – Historical data and tube samples were collected in order to establish the density (mg/cm2) or thickness (mm) of the internal oxide scales. This made it possible to assess the metal operation temperature, to be correlated later with metallographic features and the need for chemical cleaning. Results are shown on figure14, for blanc spaces there is no information, for those with numbers on white bottom chemical cleaning is not required, for those on gray bottom chemical cleaning scheduling is recommended and for those of black bottom chemical cleaning is required. As can be noticed, RH2 from unit 1 and mainly RH3 from unit 6 are in this last category.

	SH1	SH2	SH3	SH4	RH1	RH2	RH3	ECO.S	ECO.E	WL	WR	WF	WP
U 1/03						15.54	0.20*					31.01	9.46
U 1/04						62.09	0.35*						
U 2													
U 3/03		4.88	4.81			44.37						13.08	10.99
U 4						0.50*							
U 5/02												14.85	15.57
U 5/04							0.24*						
U 6/03		3.62	9.56			15.13	173.29					30.46	

* In millimeters and the rest in mg/cm2.

Wall Thickness Measurement. - Profile of wall thickness of SH and RH tube banks was obtained by means of the ultrasonic testing. Areas with lower wall thickness were detected, corresponding to the same ones that were more affected by higher temperatures, measurements on SH3 from unit 1 is presented as an example in figure 15, reflecting as well the temperature distribution through the bank.



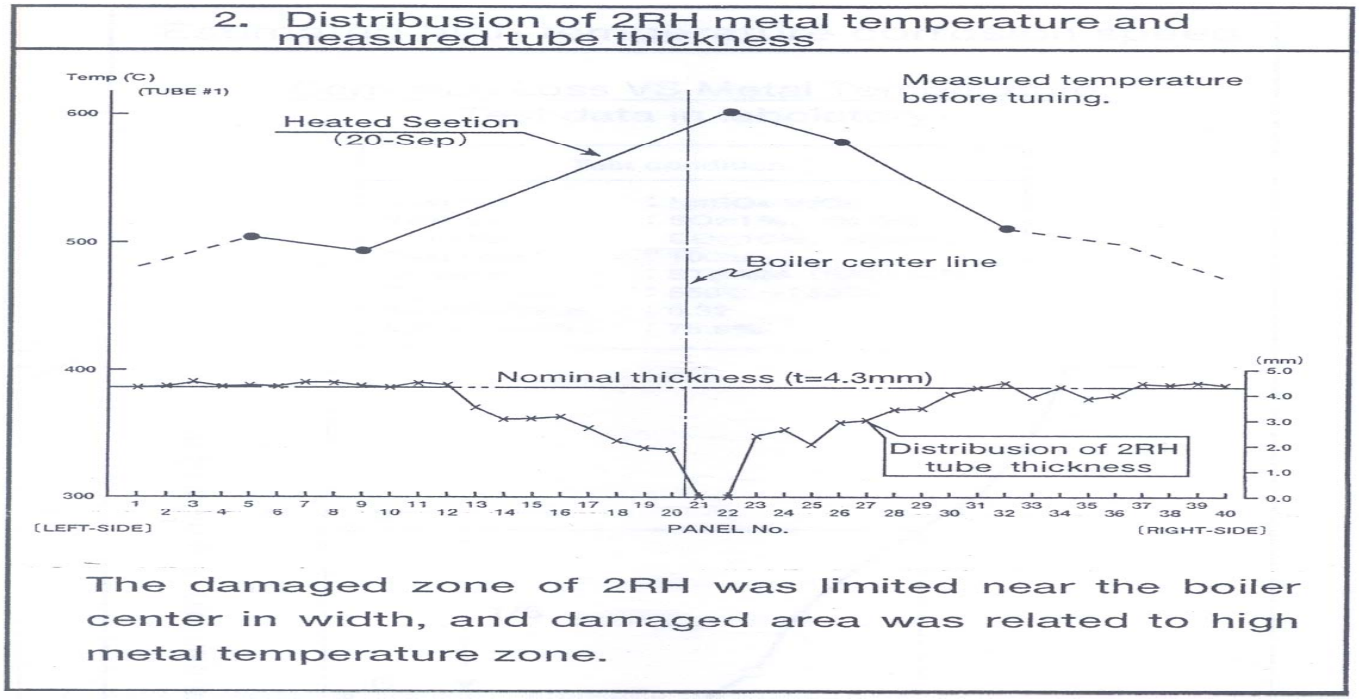
	SH1	SH2	SH3	SH4	RH1	RH2	RH3
U 1						OK	OK
U 2						OK	OK
U 3				OK			OK
U 4							
U 5							OK
U 6							OK

In this case gray is closed and black is under the lower permissible limit according to ASME.

Remaining Life Assessment. – There was only one residual life assessment, which was carried out on unit 5, several areas of the SH3 were judged to have between 6,875 and 21,018 Hrs of remaining life.

Historical Studies. - An exhaustive search of previous studies was made during the RCA process, operational records were also reviewed. It was found that in 1995 some overheating failures took place located on RH2 of unit 4, only after 12,740 hours of operation. CFE carried out some testing an the original equipment manufacturer conducted an investigation in order to clarify the equipment performance, as a result, growth of the internal oxide and overheating features were observed in metallographic samples, on the other hand, reduction of wall thickness was evident by ultrasonic examination, which was indicative of higher temperature incidence on the central area of RH2. Conclusion was that failures were as a result of heterogeneous distribution of temperature inside this bank and that the highest metal temperature reached was 665°C, according to the internal oxide scale growth. Countermeasures included the modification of some operational parameters, specifically related with adjustment of

burners, a reduction of metal temperature in the range of 582°C was attained. Figure 16 illustrate what was reported at that time.



Logical Failure Tree:

The logical failure tree is shown in annex 1 (figure 17). Following the road from the start to the finish, it begins by defining the problem as Recurring BTF. In the following level, Steam Touch Tubes branch is selected. The following lower level is represented by the different failure mechanisms according to the nomenclature proposed by EPRI. Long term overheating is chosen and next lower level includes all its possible failure mechanisms. From this stage, three branches from all possible ones are explored: Build-up of Internal Oxide scale, Increases in Stress Due to Wall Thinning and Operating Conditions. In next lower level Initial Design is considered and Operating Conditions are evaluated again, this time associated with Erosion / Corrosion. All this represents the Physical Root Causes as were defined at the beginning. Increases in Stress Due to Wall Thinning belong to another branch where Tube Manufacturing Defects and quality control practices are considered

In next descending level, some of the possible human root causes are explored such as the Inappropriate Combustion System Adjustment, the Lack of Awareness of Design Limitations and the Inappropriate Quality Control Practice of the original or replacement tubing.

Finally the lower level is focused toward latent root causes; in fact these are organizational systems deficiencies that allowed the failure risk to become present, such as the Lack of Training, the Lack of Supervision, the Lack of Appropriate Information for Decision Making, the

Existence of Inadequate Procedures, either of operation, quality control, training or maintenance among others. At this final point, is where the Root Causes are encountered. Organizational systems are put in place to help people make appropriate decisions, if they are inadequate or obsolete a risk situation could arise. These are the true root causes of undesirable events.

Conclusions:

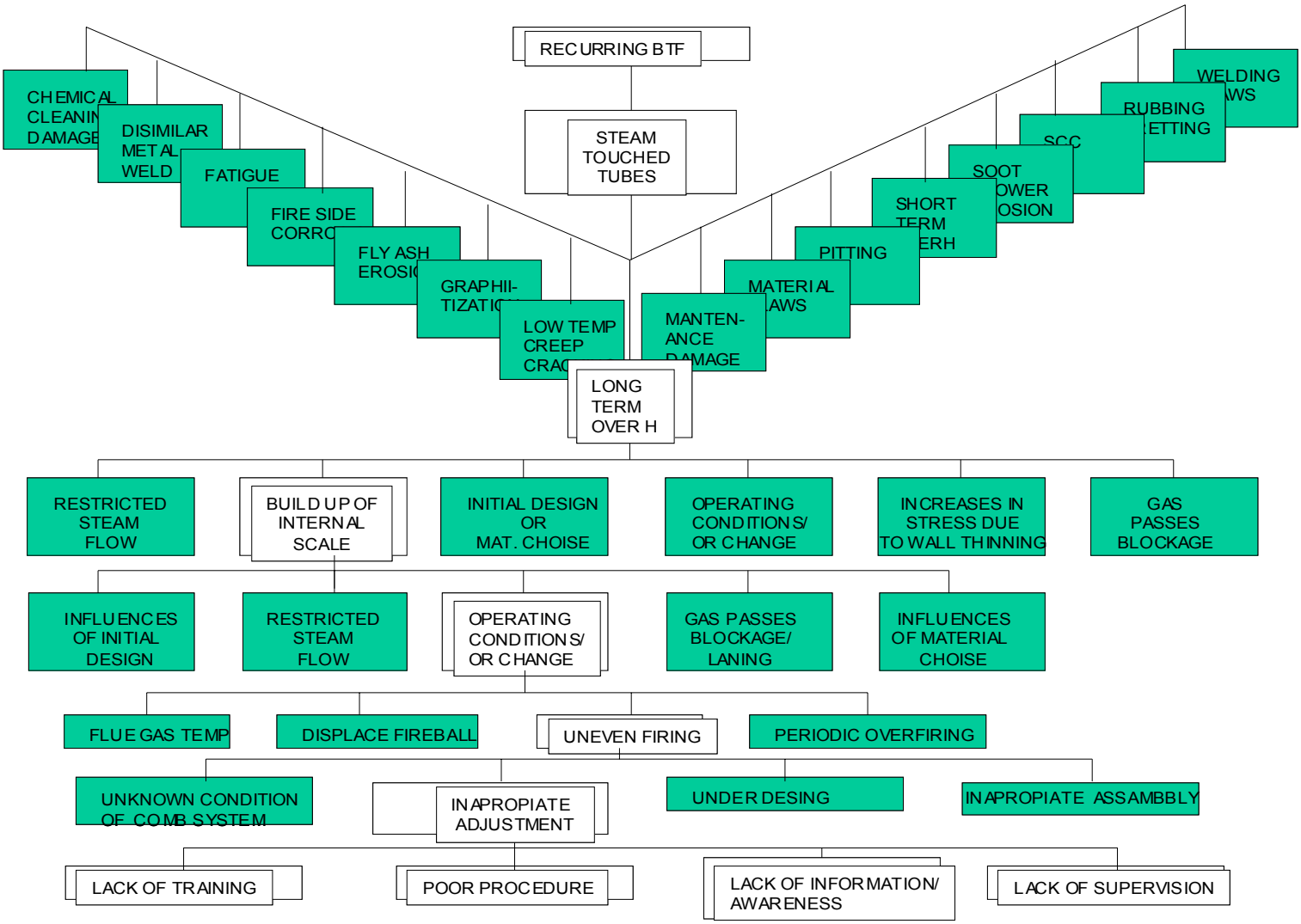
When the RCA methodology is applied to BTF, it is possible to visualize all failure events in an accessible and objective way, cause and effect relationships can be put in place and evaluated. True root causes are encountered and corrective measures can be tailored. Considerable decrease or elimination of the recurrence risk is attainable and continuous improvement can be monitored as well. Lastly, when RCA methodology is implemented and used repeatedly, it becomes a proactive tool.

As conclusions for the case presented, the most significant tube failure locations and mechanisms were identified as a function of failure frequency, last root causes were encountered and recommendations were implemented. In the near future, accordingly with the whole implantation of the methodology, an improvement of availability factors is expected. On the other hand, questions regarding similar failure patterns and the influence of the burned fuel were clarified. As a result, recommendations including the establishment or revision of procedures for burners adjustment and monitoring, training and quality control of replacement tubing were established in order to decrease the risk of unforced outages due to BTF.

References:

1. **-** Barry Dooley and Warren McNaughton, *Boiler Tube Failures: Theory and Practice, Volume 1 and 3, Palo Alto, CA: EPRI 1995. TR-105261- V1 and V3.*
2. – Robert J. Latino and Kenneth C. Latino, *Root Cause Analysis: Improving Performance for Bottom- Line Results, CRC Press, second edition.*
3. – Alejandro Ruiz Rodriguez, Petacalco Station Failure Analysis Reports 2001- 2003, CFE/ LAPEM, Mexico.

Annex 1: LOGICAL TREE



Note: inccreases in Stress Due to Wall Thinning branch is not showed because of space, as a result quality control procedures and practices for replacement tubes are analysed in that branch.

SESSION 6: Welding and Repair Aspects

Chairman: T. Kirwan, ESB

WELD JOINT FAILURE AND SUCCESS IN REHEAT REPLACEMENT PROJECTS

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1.0) ABSTRACT

There are a variety of challenges facing owner / operators of coal fired, steam generating boilers when major mechanical component replacements are required. Items such as budget, schedule, and manpower availability are typical constraints for a large scale project.

This paper reviews two partial reheat section replacements at Hoosier Energy's Merom Generating Station. The initial replacement was planned with the utilization of a proven automated welding technique to aid with known manpower availability concerns at the time of the replacement. The initial project was pushed passed its original schedule when unexpected weld rejects surfaced during the initial quality control checks. The paper also reviews the engineering and planning efforts used to solve the initial weld joint issue and follows through with the success of the second replacement project utilizing a similar automated welding technique.

2.0) INTRODUCTION

Hoosier Energy R.E.C., Inc. is a generation and transmission utility system owned by 17 member system cooperatives. Hoosier Energy owns and operates the Merom Generating Station located in Sullivan, Indiana. The Merom Station is a steam-cycle electric generating plant with two 490 net megawatt coal-fired units. The boilers were manufactured by Riley Stoker Corporation and have been in operation since about 1981. Each boiler supplies steam to two Westinghouse boiler feed pump turbines along with a Westinghouse turbine generator set. The Riley Stoker boilers were built for maximum drum design pressure of 2,900 psig and is capable of producing 3.9 million lbs/hr of steam at 2,630 psig and 1005 degrees F.

3.0) MEROM STATION REHEAT SECTION HISTORY

During the late 1990's and into the year 2000, the Merom Station began experiencing an increased number of tube leaks in the reheat sections of its boilers along with other sections. With major outages scheduled on both units in 2001 and in 2002, Hoosier Energy planned to perform full assessments on both of the boilers for use in future repair and replacement strategies.

Results of the Unit #2 assessment in 2001 indicated the middle third of the reheat section had reached the end of its useful life. Ultrasonic thickness testing in the lower portion of the bundle indicated severe thinning throughout the section due to sootblower erosion. In the upper portion of the bundle, metallurgical evaluation indicated the bundle was suffering from long term overheating. The estimated life expectancy for this bundle was reported as less than two to three years. To aid in maintaining the reliability of the unit, temporary repairs were implemented until plans could be made for replacement.

Given the major outage scheduled on Unit #1 in the spring of 2002, Hoosier Energy utilized the year 2001 summer preparation outage to perform a similar analysis in the Unit #1 boiler. As expected, the findings for Unit #1 were similar to those found on Unit #2. Again, the upper portion of the bundle was determined to have the long term overheat condition. The lower portion of the bundle also showed the severe thinning due to sootblower erosion. Less than two to three years of life expectancy was reported for the Unit #1 bundle as well.

4.0) UNIT #1 PROJECT DEVELOPMENT

With continued tube failures expected in these sections of the Merom Station boilers, Hoosier Energy began developing the plans for replacing the middle third of the Unit #1 reheat section during the major outage in 2002. The original bundle was designed with an upper and lower set of weld lines and had been manufactured from SA 178 grade A material. The tubing dimension at the lower weld line was 2.5" O.D. by .135" wall thickness. The tubing dimension at the upper weld line was 2.25" O.D. by .134" wall thickness. In addition to the dimension change at the upper weld line, the tubing also changed from the SA 178 grade A material to a SA 213 T11 material. The bundle consisted of one hundred ninety-two elements across the width of the boiler.

Replacement of this portion of the reheat section would require a total of 1,928 welds. Since one of the mechanisms contributing to the failure of the bundle was overheating during normal operation, Hoosier Energy chose to upgrade the replacement bundle from SA 178 grade A to SA 213 T11 material. With the upgraded bundle, 768 welds would be SA 213 T11 to SA 213 T11. An additional 768 welds would consist of SA 178 grade A to SA 213 T11 material and the remaining 392 welds were to be SA 178 grade A to SA 178 grade A.

The large number of welds required to complete this project also raised a question of manpower availability. All demolition, installation of the new bundle and weld out would have to be completed in the scheduled seven week outage duration. Issues with manpower during the outage would have posed possibilities of startup delays and additional costs to the company. During this time frame, SCR construction was in progress at Merom along with other local facilities and finding certified welders for even small projects had become increasingly difficult. Discussion with the Boilermaker Union further indicated that manpower for this large scale project would not be available through the national labor force. Knowing the project had to be completed for the reliability of the station, Hoosier Energy was forced to look at alternate methods.

The automated welding process was introduced to Hoosier Energy through attendance at a conference in the fall of 2001. WSI was in attendance and was asked to present their capabilities to the Merom Station project personnel. After the initial presentation, a tour of their facility was arranged to further investigate the automated welding process and to witness actual welds being made. Sample tubing from the reheat bundle was shipped to the WSI facility for the initial tour weld mock up. Personnel from the Merom Station also traveled to a job site to watch the automated process in a field setting and to see how the local labor force worked with WSI's crews. Cooperative union labor interaction with WSI's crews was identified as a key element for successful project execution.

Hoosier Energy's initial investigation of the automated welding process revealed that though more costly, the process was faster than traditional labor and produced few if any rejects. Furthermore, WSI's policy of repairing any weld failure at no cost to the customer aided in determining the viability of the automated process. Again, faced with maintaining the reliability of the Station, completion of the project during the 2002 scheduled outage was a priority. Knowing that traditional labor would not be available for the project, WSI was chosen to perform the weld out of the new bundle. The estimated additional costs for utilizing the automated welding systems along with the local labor force to complete the replacement were between thirteen and fifteen percent of the total project cost.

5.0) UNIT #1 PROJECT PLANNING

The planning of this work began in early January 2002. Hoosier had decided to work together with WSI and Sterling Boiler and Mechanical Inc. to execute this critical scope of work. Throughout the process there were various conference calls, and planning sessions including a trip to WSI's shop facilities in Norcross, Georgia. The purpose of this trip was to witness mock-ups of the equipment, and review the project in person with Hoosier Energy, SBMI and WSI all present. The final plan was developed in a meeting at the Merom Station where the Superintendents, Foreman, QC and Project management were present.

Based on the strategic plan for this project, WSI's role was to perform the welding scope of work. Specifically, WSI was responsible for the fit, tack and welding of 1928 tube joints. The demolition, installation and aid in fit up of the new bundle was to be completed utilizing Hoosier Energy's maintenance alliance partner SBMI. SBMI has a long standing relationship with Hoosier Energy and was supplying the majority of the manpower for remaining planned maintenance activities during the outage. To make the welds, WSI had chosen to use their patented "Single Pass" insert. As the name indicates, the insert was to become the root, fill and cap passes of each weld joint without the need for any additional weld wire feed. This method was chosen to improve production over multi pass inserts, and manual welding. This method had also been proven by WSI in several prior projects.

As mentioned previously, a concern about the execution of this project for Hoosier Energy was the integration and coordination between WSI and Sterling Boiler and Mechanical. To minimize any issues with responsibility between the contractors, separate contracts were written for the work. Each contract detailed the specific requirements of each party during the project.

The labor portion of the planning was also critical to the project. WSI's procedure is to contact the local BA in the area where the work is to be performed; to inform the local BA what work WSI will be performing, how many personnel will be working for WSI, and determine how many local personnel will be needed to support their work. This process allows for smooth communication and planning at the local level, as well as for WSI. WSI's approach also helps develop positive working relationships with the local Boilermakers and the BA, this is very important to the flow of the work, and to the attitude of the work force on a project.

6.0) UNIT #1 PROJECT EXECUTION

The execution of the Unit #1 project did not progress as had been expected from the initial planning. SBMI was able to complete the demolition of the old bundle and begin the installation of the new bundle per the original schedule and WSI was on site with their associated equipment as planned. However, equipment problems slowed WSI's start of the bundle welding process. All groups were anxious to begin welding and to verify the low rejection rates that WSI had proven in prior projects. As a precaution, a local RT company had been asked to shoot the very first set of welds made by WSI for verification.

The first set of RT results indicated serious porosity problems in the welds and that the single pass insert was not forming a completed weld. Finished welds were flush with the original tube material and in some cases undercut from the original tube wall. Continued RT as additional machines were placed in service revealed the problem was widespread and not a single machine or manpower issue. WSI continued placing machines in service and also began making the required repairs from the previous RT results. However, the number of rejected welds was increasing and the ability for WSI to make the planned daily weld count per the original schedule was impacted.

In an attempt to get the project back on course, a meeting was scheduled with Hoosier Energy, WSI, and SBMI. To make up the weld counts required to meet the schedule, all groups agreed to refrain from RT for a few days and to concentrate on getting welds completed. The intention was to allow WSI to get caught up on the weld count and provide uninterrupted access so the schedule could be regained. This plan also proved unsuccessful as the RT process continued to compile rejected welds. It was evident that further changes and cooperation by all parties would be required to complete the project.

The situation was also adding significant stress to the project, and the relationship between contractors and Hoosier. WSI was determined to understand the reasons for the failures.

On the job-site there are many variables that can affect the success of the welding. At this point with the rejection rate increasing, WSI began to evaluate all of the possible variables. The first item evaluated was the labor resources on the project; did the welders have the appropriate certifications, and qualifications. Second WSI began to evaluate the conditions in which the welders were being asked to work and the type of welds that they were being asked to make. New to old, and new to new as well as the position of the weld, and the area (physical) in which they are being made. Unfortunately, after completing the evaluation, it was

determined the majority of the necessary plans were already in place. The only exceptions were the condition of the equipment itself; upon arrival at Hoosier Energy the equipment was in need of repair, and it required three days worth of work to get all of the systems in working order.

The other area WSI began to evaluate at this point was weld procedures; including gas mixture, weld wire, pre heat requirements and procedures, etc. With all of these possibilities accounted for, WSI turned to the consumable inserts. First evaluated was the manufacturing process of the single pass inserts. The process used at that time included applying a 360 degree overlay on a tube, cutting out the base material and leaving the actual weld material to be machined for the joint configuration.

Hoosier Energy sent inserts out for X-Ray, and the film showed clearly that the inserts themselves had porosity. The reason for the weld failures was porosity as well. In addition, there were a substantial number of New to Old welds that needed to be made. These were also causing a problem.

The higher reject rate on new to old joints suggested that standard cleaning and machining techniques might not be removing all the contaminants. Chemical cleaning of boiler tubes or hydrogen build up was suspected as a cause for the porosity. With this in mind, WSI decided to change the work procedure. WSI started performing a bake out of the tube prior to welding; this was to ensure that they were removing any potential contaminants from the old tube. Also they began to fit and tack on days only, and weld on nights only to gain a better measure of the welding and welder quality. WSI completed the project in this fashion as the failure rate improved, and the project began to make progress. However, WSI ended up repairing some welds multiple times due to the inconsistency of the inserts, and the failures associated with them.

7.0) UNIT #1 LESSONS LEARNED

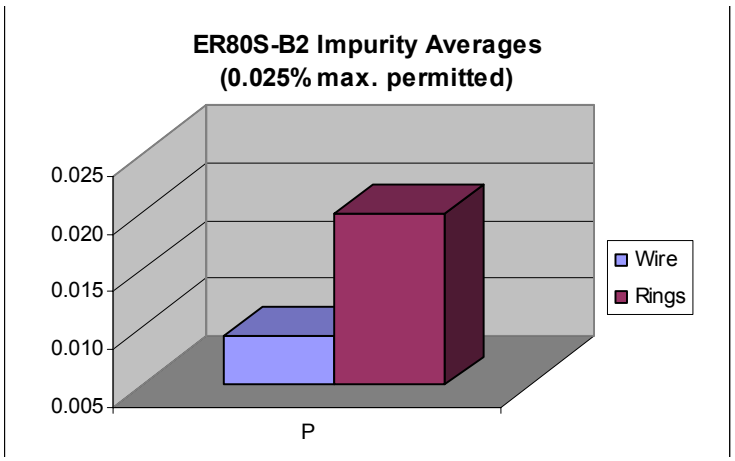
After the project was completed, Hoosier Energy and WSI began to evaluate the lessons learned from the first project. Each company had shared interests in solving these issues, since the sister unit would have the same scope of work in the coming year. Hoosier still faced the same labor issues and WSI wanted to prove to Hoosier that WSI could do the job well and without failures.

The first area of concern was the single pass inserts designed by WSI; how they were manufactured and how they performed under specific conditions. Since weld porosity was the primary reason for rejection, this area became the focus. WSI evaluated their manufacturing process which

included creating a weld deposit with the desired filler metal, and then machining the inserts from the weld deposit. This process was used due to the unique shapes and sizes of the inserts; purchasing these commercially was not cost effective. This is why WSI began manufacturing their own inserts. Since the inserts were manufactured in the shop, they began to evaluate all of the variables that would lead to porosity. When evaluating the chemistry results of the shop manufactured inserts WSI learned:

- Chemistry results proved the insert chemistry was within the code acceptable chemistry ranges
- Crucial elements related to porosity prevention were depleted
- Specifically Silicon and manganese
- Additionally Phosphorous was seen to be at higher levels than expected (phosphorous acts as an impurity).

This chemical analysis demonstrated that while within specification, these inserts were less resistant to porosity due to the depletion in Silicon and Manganese, and the presence of greater amounts of phosphorous. This analysis indicated that while WSI was within full compliance with specification, the insert technology was less resistant to porosity formation than new bare wire. Using ER80S-B2 as the base material for the study from which the inserts were manufactured, the results are listed below:



With this in mind WSI conducted a series of tests. Testing included a side by side comparison of old and new inserts (old being those manufactured by welding, new being those manufactured by bar stock).

Several terms used in the following test descriptions warrant definition:

- Old Insert: Insert manufactured by weld deposition
- New Insert: Insert manufactured from bar stock or another wrought product form
- Purge: Inert gas (argon) internal purge, accomplished by inserting physical blockages (purge dams) in the tube and introducing an inert gas to displace atmospheric air with the inert gas. Purge reduces contamination of the molten weld pool and thereby reduces susceptibility to porosity and other defects.
- Preheat: Heating of the weld area and immediately adjacent base material with a torch or other heating device to the specified minimum preheat temperature. Preheat is accomplished immediately prior to welding, so that the weld area is at or above the minimum specified temperature when welding is initiated.
- Bake out: Heating of the weld area and immediately adjacent base material with a torch or other heating device to a temperature in the 600°F to 800°F range, and maintaining this temperature for a time period of approximately 30 minutes.

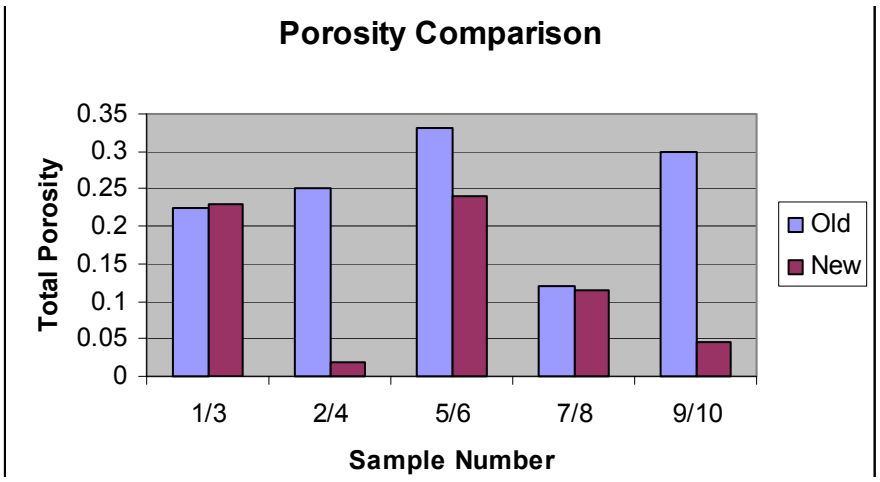
- ER80S-B2 Insert Materials: This specification was chosen based on the material utilized for the fabrication of the new reheat bundles. Hoosier Energy chose an SA 213 T-11 material, therefore by code WSI was required to use an 80S weld material. WSI chose 80S B-2 material for the manufacturing of both the old and new inserts.

Test Phase 1:

Ten welds were installed on new SA-213 Grade T11 tubes. ER80S-B2 inserts were used. None of these test weldments used elevated preheat (no heat was applied prior to welding) or bake out, and none used an internal purge. The following table summarizes the welding conditions for each coupon and the radiographic test results:

Coupon Number	Old or New Insert	Base Metal Condition	Radiography Results
1	Old	Fully cleaned to bright metal	Accept
2	Old		Accept
3	New		Accept
4	New		Accept
5	Old	Tube cleaned, then tube ends dipped in contaminant (water-soluble cutting fluid)	Accept
6	New		Accept
7	Old	Tube cleaned, then tube ends contaminated with WD-40 oil	Accept
8	New		Accept
9	Old	Tube ends cleaned, then placed in water to form rust. Rust then contaminated with WD-40 oil	Reject
10	New		Accept

The approximate number and size of porosity pores were measured to determine the relative porosity level in each coupon. The following chart summarizes the results.



A reasonable correlation between porosity and insert manufacture was established, particularly in coupons 5/6, 7/8, and 9/10, where contamination levels were most severe. In samples 9 and 10, which represented the worst contamination conditions, new insert materials showed a marked increase in porosity resistance. Test Phase 1 results confirmed that, when contaminant levels are high, inserts fabricated by welding are more susceptible to porosity than inserts fabricated from bar stock. With these results in hand, WSI initiated Test Phase 2.

Test Phase 2:

This test phase served as an evaluation of new consumable insert rings under conditions simulating actual field butt welds. Several sections of SA213 Type T11 tubing were used, each of which had been in service in operating boilers. Test conditions were as follows:

- Test weld configuration was typical of that in which field butt welds are installed; with each test sample consisting of a full-penetration butt weld joining a section of service-exposed tubing to new tubing. New tubing material was SA-213 Grade T11.
- Two tube sizes of service-exposed were used, with each size removed from different areas of the boiler. These service-exposed tube materials were:
    - SA-213 Grade T11 (2.25” diameter by 0.135” wall)
    - SA-178 Grade A (2.50” diameter by 0.135” wall)
        - See table “Test Phase 2 conditions and results”
- Welding was performed in the horizontal (2G) position.
- Coupons were fully cleaned, and no external contaminants were intentionally introduced.
- A 250°F preheat was used for all welding.
- Bake out was used prior to welding of some tubes; however, for these tests WSI intentionally used a lower temperature than typically used for field bake out (400-450°F for these tests vs. 600-800°F in the field). Test coupon bake out temperatures were reduced because shop conditions enable more effective bake-out than field conditions. A temperature reduction was imposed to provide a more accurate (i.e., less conservative) shop simulation of field bake out conditions.
- Bake out duration was 15 minutes for test coupons B2b and B4b. Duration was 30 minutes for coupons B2a and B4a. This variation in bake out duration served to evaluate the effect of varied bake out times on RT results.

The following table summarizes Test Phase 2 conditions and results:

Coupon Number	Coupon Diameter and Thickness	Argon Purge	Bake out Conditions	Radiography Results
1	2.25” x 0.135”	None	None	Accept (No relevant porosity indications)
2	2.25” x 0.135”	None	None	Accept (No relevant porosity indications)
3	2.25” x 0.135”	Yes	None	Accept (No relevant porosity indications)
A1	2.25” x 0.135”	None	None	Rejectable Porosity
B1	2.25” x 0.135”	None	None	Accept (No relevant porosity indications)
B2a	2.25” x 0.135”	None	30 Minutes	Rejectable Porosity
B2b	2.25” x 0.135”	None	15 Minutes	Accept (No relevant porosity indications)
B3	2.25” x 0.135”	Yes	None	Accept (No relevant porosity indications)
B4a	2.25” x 0.135”	Yes	30 Minutes	Accept (No relevant porosity indications)
B4b	2.25” x 0.135”	Yes	15 Minutes	Accept (No relevant porosity indications)
D1-1	2.5” x 0.135”	None	None	Accept (No relevant porosity indications)
D1-2	2.5” x 0.135”	None	None	Accept (No relevant porosity indications)

The following are the conclusions from the testing that was performed by WSI.

- An internal argon purge is a crucial component in porosity control. The only Test Phase 2 rejections that occurred were in coupons where an argon purge was not used. Of the eight welds installed without purge, two were rejected (a 25% rejection rate). WSI strongly recommended routine use of an internal argon purge for boiler tube butt welds in T11 base materials.

- Benefits afforded by tube bake out are limited – no measurable benefit was provided in the test samples described herein. While bake out has been proven a viable tool in applications where unusually severe service exposure/contamination exists, it is not recommended as a routine activity. Bake out is, instead, recommended as a welding option only when severely contaminated base materials are encountered.

    - As an alternative to bake out, WSI recommended use of an initial preheat as part of the weld cleaning operation. This additional preheat step consists of heating the prepared weld ends to a temperature of 300 – 400°F immediately prior to the final cleaning/polishing operation that precedes weld fit-up. This additional preheat has been shown to bring some embedded contaminants (such as petroleum residue and other compounds) to the surface of the weld prep, so that the mechanical cleaning operations associated with fit-up can effectively remove them. Initial preheating serves as an additional measure of contaminant control, particularly in locations where contamination levels are known to be significant. After this initial preheating step, the weld ends are cleaned and prepped, the joint is fit-up, purge is established, preheat is applied, and welding is initiated. Note that this additional preheating step does not mitigate or otherwise affect the preheat required immediately prior to welding.

- Inserts fabricated from bar stock provide superior weldability, particularly in applications where weld contaminants are high. The switch from inserts manufactured using weld metal to inserts machined from bar stock provides a chemistry improvement that effectively mitigates welding porosity. All WSI-supplied ER80S-B2 inserts will, therefore, be machined directly from materials with optimum chemistry values. Inserts manufactured by welding will not be used.

8.0) PROJECT #2 PLANNING

In addition to all of the testing and attention given to the insert design and manufacturing, WSI and Hoosier Energy also focused on being better prepared for the project. Multiple project approaches were evaluated to ensure that this pre-job planning step had the appropriate participants, and focused on the areas of the project that would improve the overall schedule and/or workflow.

Multiple project planning discussions were executed and there were specific discussions relative to the rigging strategy and to the final fit and tack welding of the inserts. Between WSI, SBMI and Hoosier Energy the efforts paid off in a project plan that offered an improved rigging strategy to support a schedule that was tighter than the first project. The duration of the outage for the second project had been reduced to four weeks instead of the seven weeks that was available for the Unit #1 project. Hoosier Energy's existing maintenance schedule placed Unit #2 with a four week outage in the spring of 2003. Given the condition of the bundle, this outage was the best opportunity for replacement of the bundle over the next several years.

In addition, due to the short outage duration, Hoosier Energy elected to minimize the number of field welds and have additional work performed in the shop prior to shipping. These approaches lead to a reduced weld count for the field work.

WSI also performed an independent readiness check. The equipment was sent directly from their shop, as opposed to being sent from another job site. Next, they performed their standard pre job calibration and equipment review under the direction of Project management, and corporate management. WSI agreed that the site management team would come to the job site three days earlier for a site evaluation, walk down and equipment review. The combined effort by the vendors and Hoosier Energy provided confidence for a successful project.

9.0) UNIT #2 PROJECT EXECUTION

After extensive planning and testing by SBMI, WSI and Hoosier Energy, the Unit #2 project was completed on schedule and within budget constraints. Although a significant number of welds had been reduced from the Unit #1 project, the outage duration had also been reduced. Upon completion of the Unit #2 project, 1,544 welds had been made and

out of nearly four hundred that had been tested, only five had been rejected and needed repaired.

10.0) CONCLUSION

To summarize, WSI's automated welding process for completing boiler tube replacements has been proven as a viable alternative to the traditional manual welding process. Although the initial project did not progress as had been expected, the second project was very successful through all phases. To complete the second project, a significant amount of dedication was put forth by all groups involved. Tube sample analysis, testing, and extensive pre-planning of the project were all necessary for its success. Through each of these steps, new developments and ideas were generated and eventually led to changes in insert manufacturing, how the elements were manufactured and even how the cabling was run into the boiler. The end result was a successful project that was completed within both schedule and budget constraints.

ALTERNATIVE FILLER MATERIALS FOR DMWs INVOLVING P91 MATERIALS

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Abstract

In the late 1980's the domestic utility industry suffered from dissimilar weld (DMW) failures between low alloy ferritic tubing and austenitic tubing in superheaters and reheaters. EPRI performed extensive research into the problem and found that nickel based filler metals provided significant service life improvements over 309 SS filler metals. Improved joint geometries and additional weld metal reinforcement were determined to provide added service life. A new nickel-based filler metal was also developed that provided similar thermal expansion properties to the low alloy base metal. The new filler metal exhibited low chromium content that would result in a smaller carbon denued zone than currently available fillers. This new filler metal was never commercialized because of a tendency to microfissure, which resulted in less than desired service life. This paper discusses a further investigation of the filler metal microfissuring and looks at long term testing to determine suitability of the filler for high temperature applications.

Introduction

Weld transitions between ferritic and austenitic tubing in superheater and re-heater sections have a history of failing before design lives have been reached (1). There are several reasons for these premature failures including:

1. Thermal stresses caused by differenced in coefficient of thermal expansion
2. Carbon denuded zones caused by carbon migration from low alloy base metals to higher alloyed filler metals

A new filler metal (HFS6) was developed in earlier EPRI work that would solve these problems (2). It contained low chromium content that would result in a smaller carbon

denued zone than available nickel-based and austenitic fillers (3). The high nickel content of the alloy resulted in thermal expansion similar to low alloy ferritic tube materials. However, the new filler metal was never commercialized because of a tendency to microfissure, which resulted in less than desired service life. The chemical composition from the filler material specification and from actual electrode and deposited weld pads is listed in Table 1.

Table 1: Chemical composition of HFS6 electrode from reference 1.

Heat	C	Si	Mn	P	S	Cr	Mo	Fe	Al	Nb	Ti	Ni
Specification	0.04	0.75	0.9-1.5	0.015	0.015	7.5-9.5	1.5-2.5	Bal	0.1	0.1	0.1	43-50
DI2956	0.09	0.13	0.82	0.0015	-	8.05	1.79	Bal	-	-	-	42.0
9561-014	0.04	0.47	1.25	0.001	0.005	8.80	1.98	Bal	-	-	-	44.32
6568-P1950 [a]	0.03	0.54	1.26	0.005	0.003	8.26	1.87	Bal	0.01	-	0.03	43.36
6568-P1950 [b]	0.04	0.60	1.45	0.014	0.003	9.25	2.28	Bal	0.04	-	0.011	47.65

a Analysis from a weld pad.
b This was a check analysis on the same heat as (a) but from a weld plate.

With the development and use of higher strength alloys in new power installations, specifically Grade 91, EPRI's Materials and Repair Program saw a need for further research into this filler metal. If the microfissuring could be eliminated, the filler metal would offer substantial benefits in weld joints between Grade 91 pipes and tubes, as well as joints between Grade 91 and low alloy ferritic or austenitic pipes and tubes.

The objective of the present project targets the design and manufacture of an experimental creep-resisting nickel-based SMAW electrode to be used to produce microfissure-free weld metal deposits. The criteria established for the weld metal includes:

- Exhibit chromium content less than 10 percent
- Demonstrate thermal expansion properties similar to ferritic steels
- Develop good toughness in the as welded condition (>20 ft-lbs)
- Provide acceptable stress rupture/creep properties

In the earlier investigation, the project focus was primarily to find a weld metal suitable for dissimilar welding applications involving 300H series stainless steels (304H, 316H, 321H, 347H) and P11, P22 or P9 CrMo materials. The scope of the potential applications has now increased to not only include P91, but also the possibility of using the new filler metal for producing stub pieces that could be used in the field to make as-welded joints in P91. This type of application would require the weld metal to demonstrate sufficient strength and toughness in the as welded condition and retain sufficient

strength to match the P91 base material following a subcritical or full normalize and temper heat treatment (N+T). As a result, preliminary investigation of tensile properties following N+T was carried out as part of the current work

The current project is separated into three tasks to be performed over a three-year period. The tasks are as follows:

1. Development of microfissure-free electrode
2. Preparation of sample coupons
3. Metallurgical, physical and long term rupture testing

This paper describes the results of Task 1, along with some of the early development in Task 2.

Task 1: DEVELOPMENT OF MICROFISSURE-FREE ELECRODE

Alloy Development

Owing to the promising nature of the results on the original electrodes, the original composition was used as the starting point for work in this project. It was considered important to reproduce compositions of good technical purity close to the original so that its susceptibility to microfissuring could be confirmed, and against which improvements could be calibrated. The experimental plan involved producing numerous heats of electrodes in which the variations were primarily carbon, manganese and niobium. The effect of carbon was investigated up to ~0.12%, the effect of manganese up to ~2.3% and the effect of niobium up to ~2.0%. Over fifty-five experimental heats were produced and evaluated, however specific chemistries will not be presented in this paper because evaluation is on going (4).

All of the experimental heats were used to deposit all-weld metal pads, which were then analyzed for microfissuring tendencies. The analysis pads were deposited onto carbon steel blocks using stringer beads essentially in accordance with AWS A5.11. Sufficient layers were deposited to produce an undiluted all-weld metal composition for testing.

Microfissuring

An effective test method for assessing and ranking the microfissuring susceptibility of each experimental heat of electrodes was deemed necessary to evaluate microfissuring tendency. Microfissuring occurs in the heat affected zones (HAZs) of weld beads reheated by subsequent beads. Typical microfissures can be seen in Figure 1. The technique used in the present work rearranges the beads to form a stack of single beads

in a vertical build-up similar to that used as a reference method for ferrite measurements in AWS A5.4 (Figure 2)(5).

Figure 1:Example Micrograph of Microfissuring

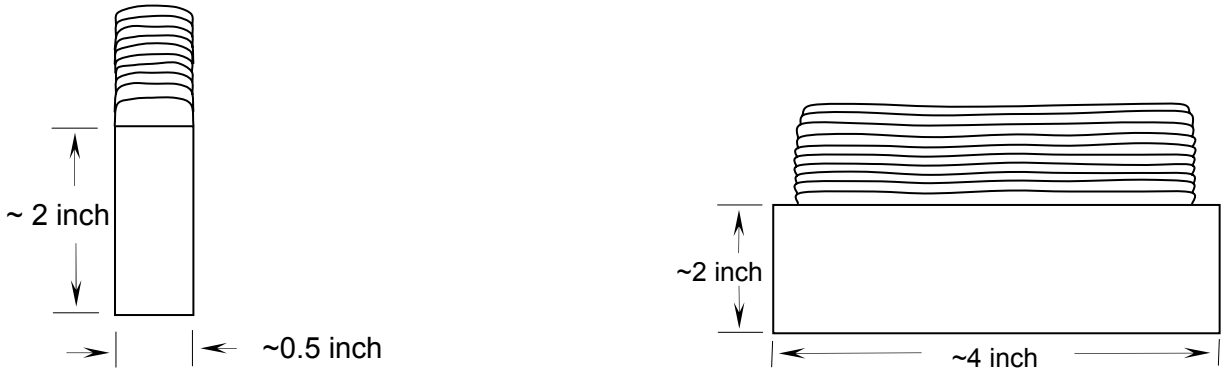


Figure 2: Microfissuring assessment build-ups.

The HAZ were therefore in underlying beads, and any microfissures were free to propagate through layers if inclined to do so. The sides of the blocks were then ground flat and any microfissures that may have been present were detected using dye

penetrant. The specimens were not preheated and were kept to a nominal interpass temperature of 300°F (150°C) maximum. All welding was performed using DC+ polarity at ~110A.

Over fifty-five different chemical compositions of filler metals were manufactured and evaluated for microfissuring tendencies. The filler metals were grouped into four major groups, A through D, and given unique identifying numbers that are used throughout this paper (for example D724). The filler metals were produced through controlled additions of sixteen different elements including carbon, silicon, manganese, phosphorus, sulfur, chromium, moly, iron, vanadium, tungsten, copper, aluminium, cobalt, niobium, tin, and nickel.

A wide range of microfissuring susceptibility was observed. For the purposes of evaluation, a microfissuring index (MI) was allocated which allowed the experimental heats to be divided into five groups. The coupons were ranked from 1 to 5, where a number one ranking indicates a very low incidence of microfissuring and a ranking of 5 demonstrates extensive microfissuring. In some cases fissures propagated almost through the full depth of the build-up (Figure 3). The allocation of a heat into a particular MI level was judged by visual examination, based on the general extent and amount of microfissuring seen in the dye penetrant test.

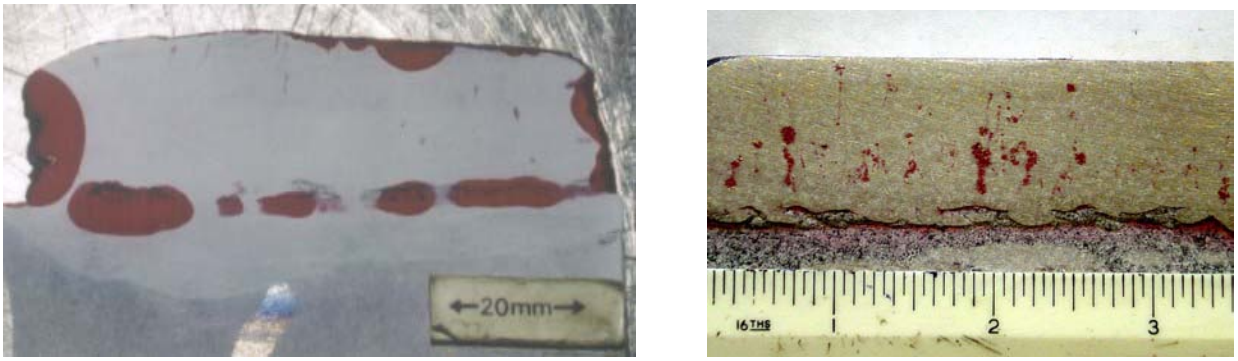


Figure 3: Extent of microfissuring found on the longitudinal face of test build-ups when ground and dye penetrant tested.

Ignoring at this stage any interaction between the various alloying additions investigated, graphs illustrating the microfissuring index (MI) versus alloying additions were plotted for each element. An example for manganese can be seen in Figure 4. Although this graph does not show a strong effect of manganese by itself, some of the graphs of other elements in combination with manganese indicated an optimum level.

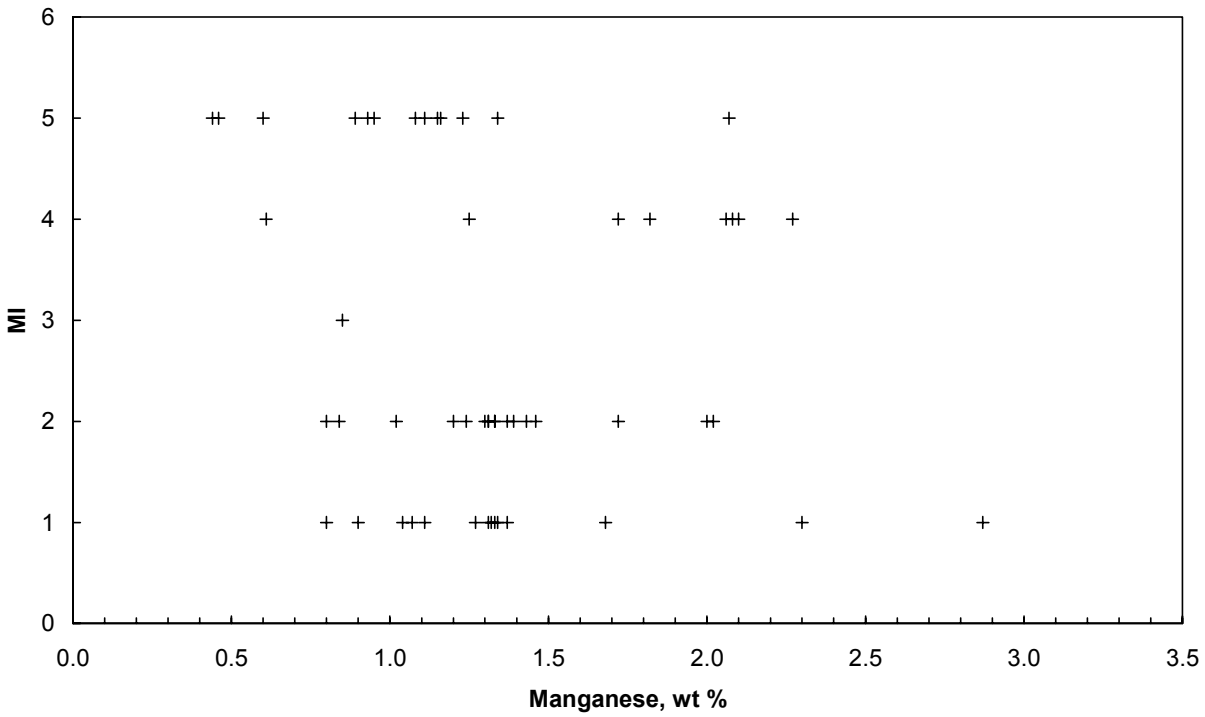


Figure 4: Microfissuring index plotted against alloy content.

After comparing the effect of each chemical on the microfissuring tendencies of the filler metal, a microfissuring factor (MF) was developed. An empirical MF formula was conceived that accounts for compositional effects of each element and provides a quick calculation to the microfissuring tendencies of each filler metal.

Evaluation of As Welded Condition

It was assumed that the filler metal would be used in one of three different heat treatment conditions. These include: 1) as welded, 2) heat treated to the base metal subcritical heat treatment (PWHT) temperature, and 3) heat-treated to the base metal normalized and tempered temperatures (N&T).[1] Most of the early testing was performed without any heat treatment, except for a few select tests where in normalization procedure for Grade 91 base metals was used.

The following provides the results of testing performed on as-welded coupons.

Tensile Testing. The room temperature tensile properties of heat D724 are given in Table 2. Heat D724, was selected because it was represented a filler metal heat with a chemical analysis within the optimum range that yielded a low microfissuring index.

[1] Note, these heat treatments are based on the normal heat treatment temperatures for the base metal.

Table 2: Room Temperature Strength for heat D724.

Temperature °F (°C)	0.2% proof ksi (MPa)	UTS ksi (MPa)	4d elongation %	Reduction of area %
68 (20)	52 (359)	81.5 (562)	34	49

The strength was comparable to what would be expected from a high nickel alloy austenitic weld metal and it exceeds the tensile requirements for P11/P22 base material given in ASME SA-335. It does not meet the tensile requirements for P91 at room temperature (Table 3). Additional discussion of this issue is provided in the next section.

Table 3: Comparison of room temperature tensile strength new alloy to various alloys (Based on ASME minimums)(6)

Alloy	UTS Ksi (MPa)	Yield Strength Ksi (MPa)
Heat D724	81.5 (562)	52 (359)
IN 182	80.0 (550)	NA
SA 335-P91	85.0 (586)	60.0 (414)
SA 376 TP304H	75.0 (517)	30.0 (207)
SA 335-P22	60.0 (414)	30.0 (207)

To evaluate the strength of the filler material at operating temperatures, two types of high temperature tests were carried out, hot tensile tests (ASTM E21 (7)) and short-term stress rupture tests (aiming for failure in 100 hours). All of the high temperature testing was carried out at 1100°F (593°C). This is the same temperature at which previous stress-rupture tests were carried out (1), and it is within the potential service temperature range for P91.

Stress rupture tests were carried out according to ASTM E139 (8) on longitudinal all-weld metal samples. All of the stress rupture tests were carried out at 593°C (1100°F) and the load for the first set of tests, 43ksi (297MPa) was selected to be about 90-95% of the hot tensile proof stress, aiming for failure to occur in a relatively short time. Based on the hot tensile properties and the result of the first set of stress rupture tests a second series of tests will be carried out for longer duration in Task 3.

Hot Tensile Testing. Hot tensile tests were carried out at 593°C (1100°F). The experimental heats tested showed quite a variation in hot strength ranging from 35.5ksi (245MPa) to 50.3ksi (347MPa) 0.2% proof stress; and 52.7ksi (363MPa) to 76.9ksi (530MPa) ultimate tensile strength.

The tensile strength and proof stress achieved with the heats containing niobium and carbon all exceed the requirements of P91 base material at 1100°F (593°C). Even though the weld metal does not meet the room temperature strength requirement of P91, it will exceed the P91 base material strength at typical operating temperatures. Table 4 and Figures 5 and 6 provide comparisons of the room temperature and elevated temperature (1100°F/593°C) tensile and yield strength of heat D724 (note the room temperature properties from Table 2 have been repeated here). The primary area of interest is above 900F as noted by the circles. These results show that over this temperature range there is only about a 20-25% drop in strength compared to the 30-50% drop seen for ferritic steels. This comparatively low drop in strength means that although the weld metal does not match the room temperature strength of P91 it exceeds its strength at 1100°F (593°C).

Table 4: Comparison of room and elevated temperature strength for heat D724 and P91 base metal at 1100F.

Temperature °F (°C)	Yield Strength Ksi (MPa)	UTS Ksi (MPa)	4d elongation %	Reduction of area %
68 (20) D724	52 (359)	81.5 (562)	34	49
1100 (593) D724	42 (290)	61 (420)	13.5	26
1100 (593) P91	32.7(226)	41.3(285)	--	--

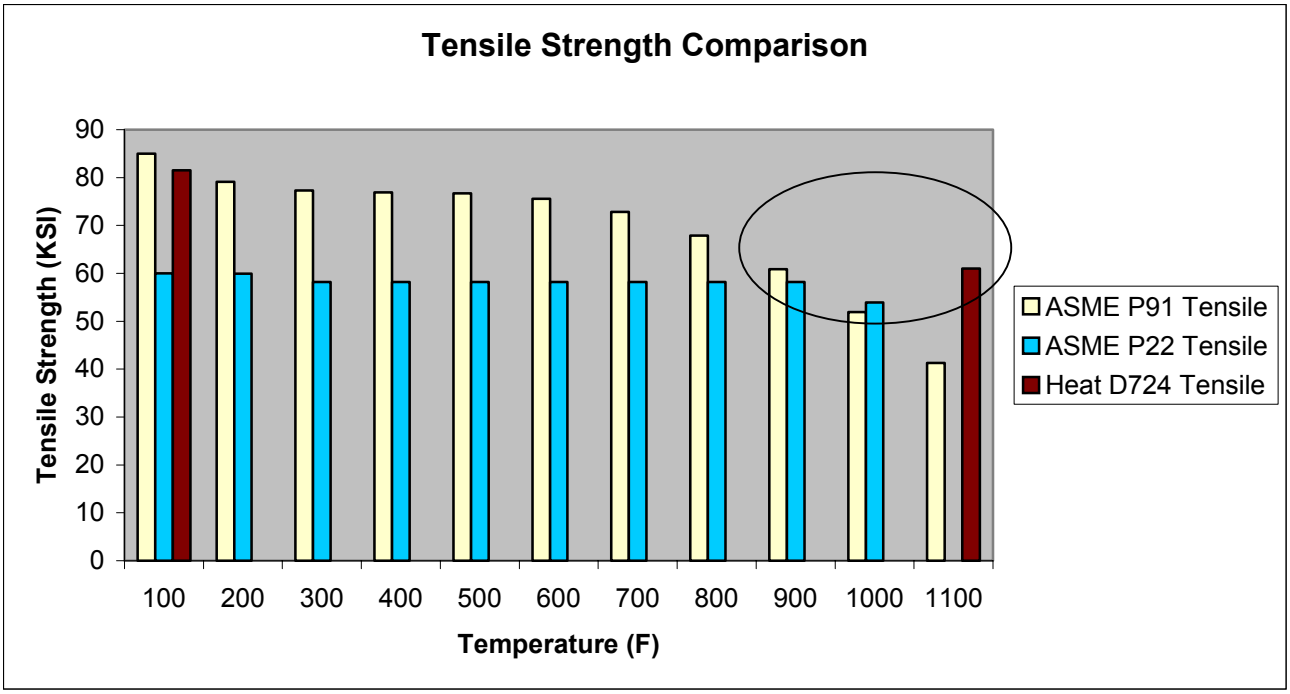


Figure 5: Tensile strength versus temperature for heat D724 compared to P91 and P22 ASME data. Note: the 1100F tensile strength for heat D724 exceeds that of both P91 and P22.

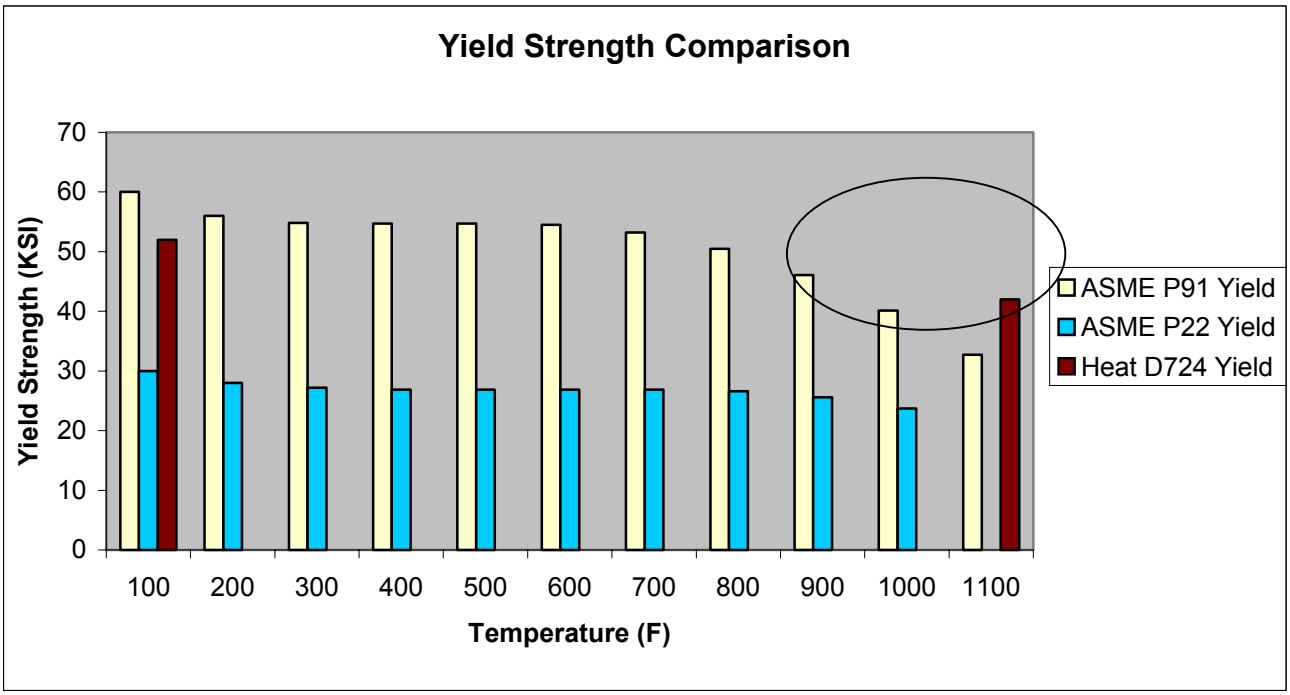


Figure 6: Yield Strength versus temperature for heat D724compared to P91 and P22 ASME data. Note: the 1100F yield strength for heat D724 exceeds that of both P91 and P22.

Toughness Testing. One of the goals for the program was to develop a filler metal that would demonstrate toughness of at least 20 ft-lbs in the as welded condition. To evaluate this, Charpy tests were carried out on heat D724. At 68°F (20°C) an average of 60 ft-lb (82J) in the as-welded condition was considered to be more than adequate for any of the intended applications. See Table 5 for the individual Charpy values and lateral expansion.

Table 5: Room temperature impact properties of heat D724

Test temperature °F (°C)	Charpy energy ft-lb (J)	Lateral expansion mils (mm)
68 (20)	67, 58, 57 (91, 78, 77)	56, 49, 48 (1.41, 1.23, 1.22)

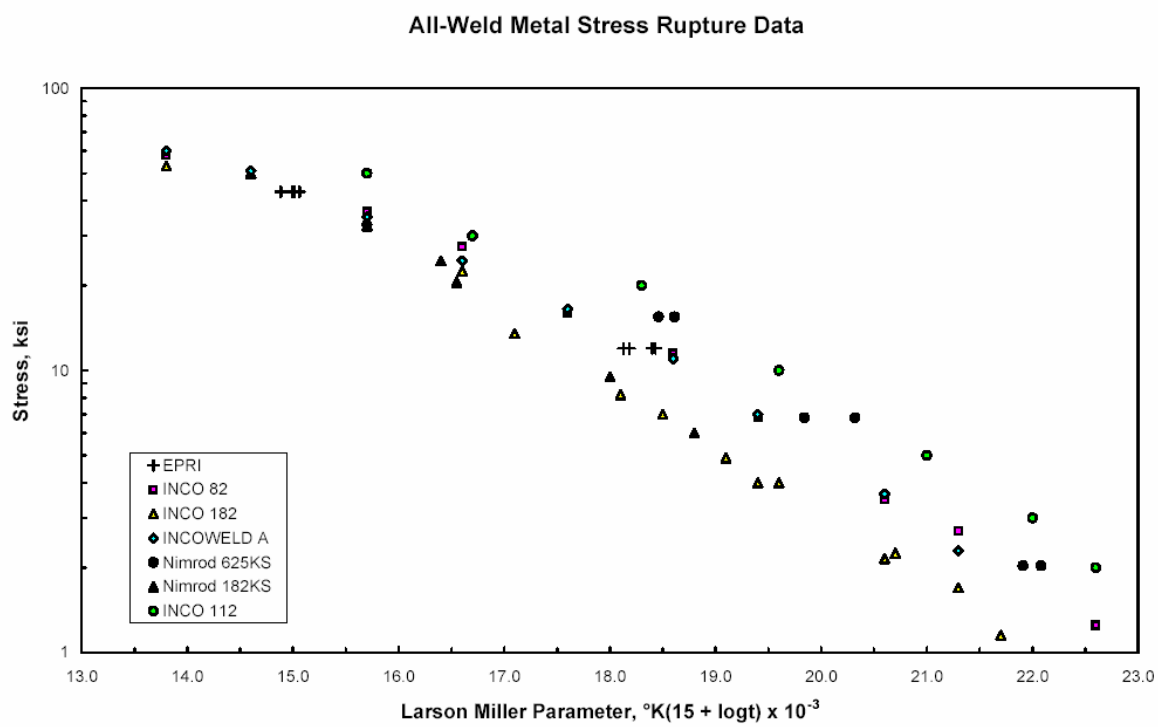
Short Term Stress Rupture Tests. Four heats (D927, D923, C269 and C273) were selected for initial stress rupture tests, including one heat containing boron (C273). The load for the first series of tests, 43ksi (297MPa), was about 90-95% of the proof stress of the weld metal at 1100°F (593°C) and was selected with the intention of achieving a rupture life of around 100 hours. Table 6 shows the results of the stress rupture tests. The original development work on the HSF6 filler metal was tested at a much lower stress (35ksi) and failed in a substantially shorter time (15 hours). **These results show a significant improvement over the original HSF6 filler metal**.

Table 6: Stress rupture test results

Heat	Test temperature °F (°C)	Load ksi (MPa)	4d rupture elongation %	Rupture reduction of area %	Time to rupture hours
D923	1100 (593)	43 (297)	8.8	33.2	155
	1400 (760)	12 (83)	6.0	25.8	354
D927	1100 (593)	43 (297)	9.0	27.2	247
	1400 (760)	12 (83)	1.8	6.2	692
C269	1100 (593)	43 (297)	11.7	39.0	204
	1400 (760)	12 (83)	2.3	10.9	401
C273	1100 (593)	43 (297)	8.5	28.9	216
	1400 (760)	12 (83)	6.1	38.3	694

Figure 7 shows a Larson Miller Plot for this alloy compared to other nickel based alloys.

Figure 7: Larson Miller Plot of Short Term Rupture Tests



Evaluation of Normalize and Temper Weldment

A proposed application for the dissimilar weld metal was to allow for buttering of weld preparations in P91 components in a shop location. These components could then be

normalised and tempered (N+T) prior to leaving the shop to eliminate the Type IV damage location and offer greater service lives than joints made with conventional B9 filler metal. An added benefit is that the components could be joined in the field without field PWHT.

As a preliminary check to establish whether there may be any loss of weld metal strength in this application, a hot tensile test was carried out on a representative heat of electrodes following a N+T heat treatment of 1940°F (1060°C) for one hour which was air cooled followed by 1400°F (760°C) temper for two hours and air cooled. This N+T heat treatment was selected as being typical of that applied to P91 base material.

Hot tensile. Heat D925 which had previously been subject to a hot tensile test and produced 49.5ksi (341MPa) 0.2%proof stress was subject to another all-weld metal hot tensile test but following a normalize and temper (N+T) heat treatment. Following a N+T heat treatment the 0.2% proof stress at 1100°F (593°C) was reduced to 33ksi (226MPa); details of results are given in Table 7. This equates to a reduction in proof stress of about a third following N+T and a reduction in UTS of about one sixth. The N+T heat treatment was selected because it was typical of that applied to P91 base material (normalize: 1940°F/1060°C one hour air cool + temper: 1400°F/760°C two hours air cool).

Table 7: Comparison of as-welded and N+T hot strength (1100°F/593°C) of heat D925

Condition	0.2% proof ksi (MPa)	UTS ksi (MPa)	4d elongation %	Reduction of area %
As-welded	49.5 (341)	76.5 (528)	21	24
N+T	33 (226)	63 (435)	24.5	33

N+T: 1940°F (1060°C) / 1 hour AC + 1400°F (760°C) / 2 hours AC

These properties were just in excess of the minimum 0.2% proof stress requirement of 211MPa (30.6ksi) at 593°C (1100°F) for P91 base material according to BS EN 10222-2:2000. These properties may require further evaluation but they were considered satisfactory for initial strength validation as a buttering layer subject to N+T.

Task 2: PREPARATION OF COUPONS FOR LONG TERM STRESS RUPTURE TESTS

Following the short-term stress rupture test, the most promising alloy composition was used to prepare 220 lb (100KG) of SMAW filler metal. To evaluate how well the new filler metal will perform in service a series of stress rupture test was proposed. The tests were originally proposed to be cross weld tests but this joint geometry would introduce two fusion zones and HAZ which would make comparison of results

difficult. Instead tests were composite rupture samples containing one half base metal and one half weld metal with the fusion line centered in the gage length (Figure 8).

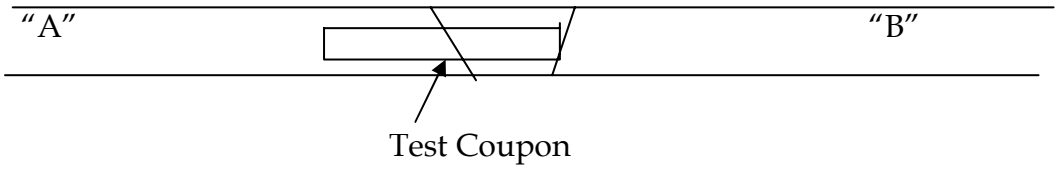


Figure 8: Coupon Location to Weld Joint

The first set of coupons was prepared to evaluate the new filler metal in the standard PWHT condition. All coupons will utilize Gr 91 on the "B" side of the weldment. "A" side will vary between three materials; Gr 22, Gr 91, and SS with coupon #1 using Gr 91, coupon #2 using Gr 22, and coupon #3 using 304 SS. Coupons were prepared using 1 ½" thick plate. The coupons on side "A" are detailed below.

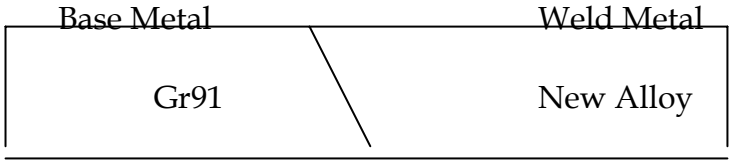


Figure 9: Coupon #1 using Gr 91 base metal

The first coupon (Figure 9) investigates a standard Gr 91 to Gr 91 weldment to determine if the newly developed filler metal shows any improvement over standard 9081-B9 filler usually utilized in these joints. Of particular concern is if the filler metal will demonstrate at least as good life in high stress short-term tests as B9 and to see if long term/low stress tests result in a type IV failure. The coupon was welded with a 400F preheat, cooled to room temperature and then subjected to a PWHT at 1400F. A picture of the completed block and a cross section are shown in Figure 10.

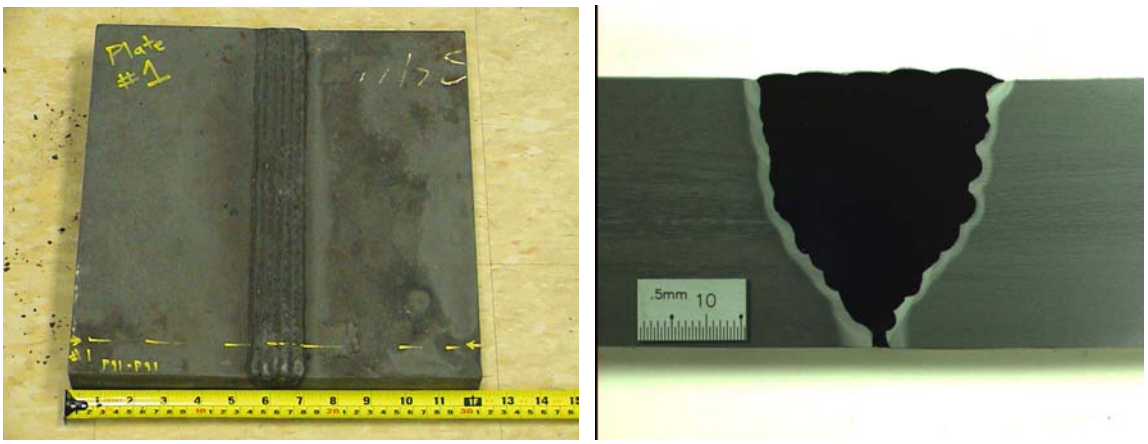


Figure 10: Completed Coupon #1 and cross section of weld.

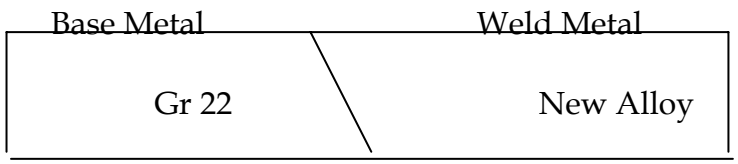


Figure 11: Coupon #2 using Gr 22 base metal

The second coupon (Figure 11) was the same as coupon number 1 except was prepared using SA 387 Gr22 base metal and was subjected to 1350F PWHT. The purpose of this coupon is to determine if any problems would develop with the filler when welding to lower alloy base metals. Carbon migration tests will also be performed on this coupon as the project continues.

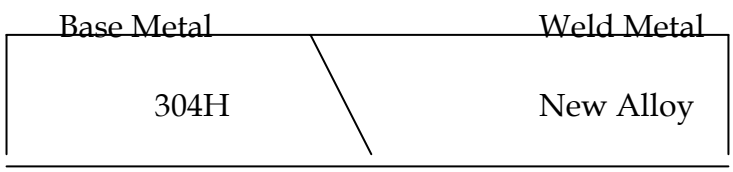


Figure 12: Coupon #3 using 304H base metal

Stainless steel (Type 304H) was used for coupon #3 (Figure 12). No PWHT was utilized. This coupon demonstrates the suitability of the filler metal being used with austenitic base metals in the as welded condition.

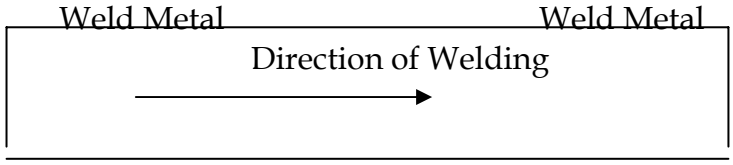


Figure 13: All weld metal Coupon #4

The previous derivative of this filler metal indicated a potential for hot cracking transverse to the weld. This test (Figure 13) was performed using a weld metal coupon with the sample removed parallel to the direction of welding. The samples received a 1400F PWHT because this is the condition that would be used on P91 joints, which are the major concern of this development.

Effect of Buttering

One of the goals of this filler metal was to eliminate field PWHT by allowing for buttering of the component followed by a standard sub-critical heat treatment in the factory. The components would then be shipped to the construction site for erection. To evaluate if a buttering followed by heat treatment would provide good service two coupons were prepared and tested.

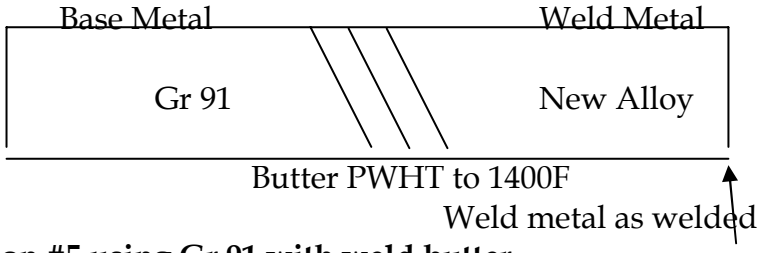


Figure 14: Coupon #5 using Gr 91 with weld butter

Coupon #5 (figure 14) has a two layer butter welded to SA387-Gr91 with a 400F preheat, allowed to cool and then PWHT to 1400F. The coupon was machined and then the weld was completed without PWHT. Testing will be performed with most of the weld in the "as welded" condition (except for the butter area).

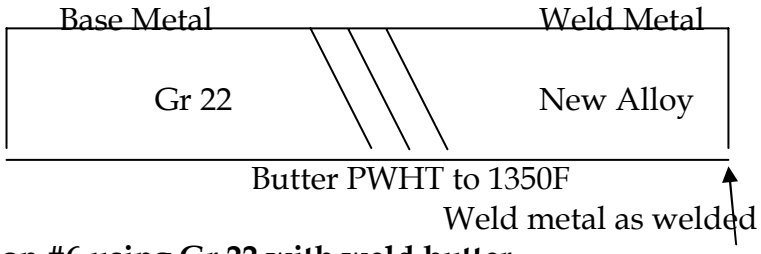


Figure 15: Coupon #6 using Gr 22 with weld butter

Coupon #6 (Figure 15) was made like coupon #5 above except the base material used was SA387-Gr22 and a 1350 PWHT was utilized on the butter. Figure 16 shows the buttered side after welding and heat treatment prior to completing the joint.

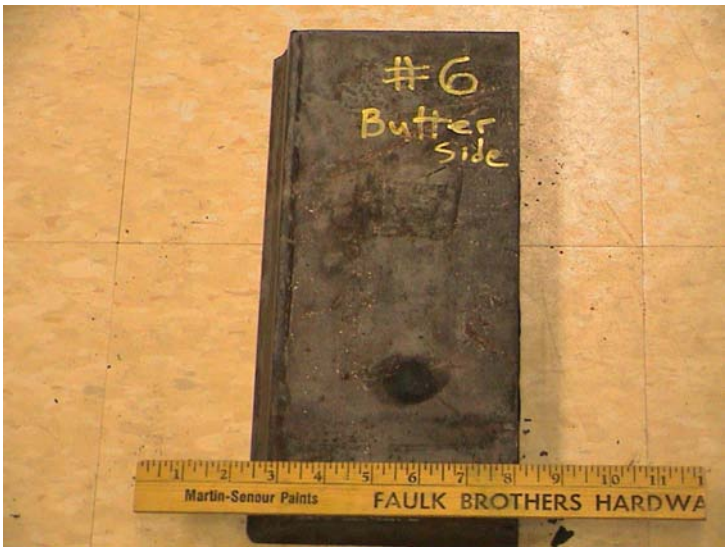


Figure 16: Coupon #6 after buttering and heat treatment prior to completion of welding.

Elimination of Type IV Failure Location

One of the problems associated with the manufacture of components is that the weldments fail in the Type IV location (fine grain heat affected zone) sooner than ruptures would occur in the weld metal or base metal (9, 10, 11). The heat from the welding process heats the metal in this zone above the lower critical temperature of the metal. P91 has been shown to loose its long-term rupture properties when heated to this level and hence the premature failures.

These failures are generally called weld failures because they are associated with welds but they are not associated with the filler metal. Developing a new filler metal will not by itself solve this problem. One goal of the current research program was to develop a welded joint what would have rupture strength equal to or better than the base metal. This would result in longer service lives of welded components.

The only way to restore properties to the HAZ is through a normalization heat treatment. Unfortunately this requires being able to join the components together without creating a HAZ. The proposed development involves buttering the P91 base metal with the newly developed alloy sufficiently thick to insulate the base metal from the heat of subsequent welding. Then a normalization and temper heat treatment would be performed to eliminate the HAZ. This requires a filler metal that does not require PWHT to develop adequate properties for service. The filler metal developed during this project should be able to offer this improvement in performance.

To evaluate the filler metal in this type of joint, coupon #7 was produced (Figure 17).

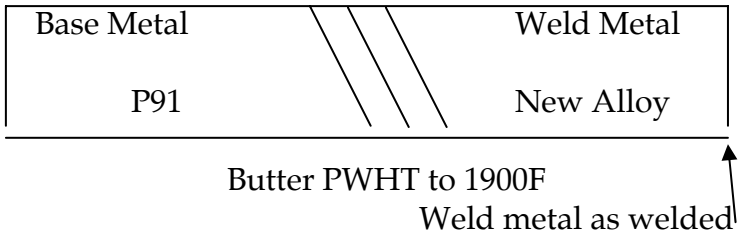


Figure 17: Coupon #7 using a butter that was normalized.

To simulate buttering in the shop followed by normalization and field erection w/o PWHT, halves of the coupon were preheated to 400F, buttered, and allowed to cool. They were then normalized at 1900F and allowed to cool prior to machining. The blocks were also tempered at 1400F prior to machining. The coupons were then joined using room temperature preheat and allowed to cool before machining and rupture testing.

Stress Rupture Testing

The seven coupons above will be subjected to stress rupture testing at 250, 500, 750, 1000, 2500, and 5000 hours resulting in 48 tests. Currently, the coupons are being tested. Some early results will be presented at the conference.

CONCLUSIONS

- A novel microfissuring test was used which was proved to be a simple and effective method for discriminating microfissuring susceptibility. This test was used successfully to rank the behavior of different variants to a baseline composition (HFS6) in a large matrix of experimental SMAW electrodes.

- A baseline composition similar to the HFS6 composition established in the earlier EPRI work was produced. This composition developed microfissuring in much the same manner as the HFS6 alloy.

- Modifications to the baseline alloy composition were completed yielding an alloy that was virtually microfissure free in the deposited condition.

- Ambient temperature tensile properties will not match P91 base material but will match lower alloyed CrMo base material e.g. P11/P22. However, properties at operating temperature will surpass the P91 base metal strength.

- The elevated temperature yield and tensile strength of the new alloy comfortably exceeds P11, P22 and P91 base material requirements at 1100°F (593°C). Hot ductility of the modified composition was determined to be satisfactory.

ACKNOWLEDGEMENTS

The authors of this paper would like to thank G B Holloway, A W Marshall, and J A Sanderson of Metrode Products Ltd and W F Newell of Euroweld Ltd. for conducting the evaluation of the new filler metal this report is based upon.

We would also like to thank the R. Viswanathan for his vision and the Metal Properties Council, Inc and GA Technologies for their support in the earlier EPRI work to develop the HSF6 filler metal that was used as a starting point for the current research.

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Consequences of Poorly Controlled Electric Resistance Welding of Boiler Tubes.

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ABSTRACT

In 1995 and 1997 two boiler tube failures occurred at Edison Mission Energy's Loy Yang B Power Station in the 4th stage superheater outlet tubing, both as a result of overheating during service. Contributing to the very premature failures were restrictions at electrical resistance (flash butt) welds joining 1Cr-0.5Mo steel stubs from the superheater inlet header to 2.25Cr-1Mo steel expansion sections. These restrictions were the result of excessive upset metal, caused by the fabrication process, within the bore of the tube. The effect of the excessive upset was to significantly reduce the steam flow within the tube and thus increase tube metal temperatures. By the use of steam side oxide surveys and further destructive sampling it was determined that excess internal upset was present in the majority of the superheater tubes.

However, the increase in tube metal temperatures resulting from the flash butt restriction was not sufficient to cause the failures observed. The root cause was subsequently determined to be pieces of nickel-rich hardfacing material which were becoming trapped in the internal upset at the flash butt welds and causing significant tube blockages. The hardfacing material was found to be originating from thermal liners located in steam temperature attemperators and was delaminating due to a combination of poor fusion between the hardfacing and liner and thermal stress.

Following these discoveries all flash butt welds were replaced and the decision taken to remove all nickel hardfacing. In order to gain access to the thermal liners in-situ for removal of the hardfacing, a process was developed whereby segments of the attemperator barrels were removed and reinstated.

1. INTRODUCTION

Loy Yang B Power Station is a fossil fired generating facility (2 x 500MW) located in the Latrobe Valley region of Victoria, Australia. The boilers are of a "tower type" construction employing 4 stages of superheat and 2 stages of reheat, and have a steaming capacity of 1562 t/hr @ 170bar and 540°C (3,444,498 lb/hr @ 2465psi, 1004°F). The first unit commenced commercial operation in 1993 with the second in 1996 and both operate as base load plant.

In December 1997, following approximately 35,000 hours operation, a steam leak was detected in the outlet header box of the Unit 1 final stage superheater. The unit was subsequently shut down for inspections and repairs.

Initial examination revealed that a tube failure had occurred at the outlet bend of a 9Cr-1Mo tube just prior to the outlet header stub (Figure 1). The tube rupture had a "fish mouth" appearance, indicative of the tube having failed as a result of creep damage. Another nearby tube was also observed to be significantly swollen at the same location (Figure 2). This same tube had failed previously (July 1995) in the same manner, however, an investigation carried out at that time did not determine the root cause.

The following description of the failures, analysis and subsequent repairs incorporates information obtained over a number of boiler shutdowns from 1997, when the cause of the failures became apparent, through to 2001 when repairs to the Unit 1 boiler were completed.

2. INSPECTIONS AND TESTING

To enable a thorough examination, both of the damaged tube circuits were removed from the boiler. In addition to a full visual inspection the tube elements were sectioned and a microstructural examination undertaken at various locations along the tube length.

Of most interest was a transition piece at the inlet end of the tube element. This piece provided a dimensional transition and also a material transition from 1Cr-0.5 Mo to 2.25Cr-1Mo (Figure 3). The transition piece itself is welded to the inlet tubing using a flash butt weld technique performed in the tubing factory. On both of the tube elements inspected it was observed that excessive internal weld upset was present at this weld (Figure 4). This excess upset resulted in a reduction of the effective internal diameters from 23mm (0.9”) to 12mm (0.47”).

An examination of the microstructure of the removed sections of tubing showed an increasing degree of microstructural damage along the tube from the inlet to outlet headers [2]. The worst degradation was observed at the 9Cr1Mo outlet tube stubs where the failure had occurred. A limited steam side oxide thickness survey of outlet header stub tubes was also undertaken at this time with the results from this survey indicating that a significant number of tubes had been operating at elevated temperatures.

It was also noted that on removal of the failed tube a piece of “foreign material” was found to be lodged in the stub opening of the inlet header. This would have further reduced the steam flow in this tube and contributed to the failure.

Given the above findings it was determined that more thorough inspections would be required and a further inspection outage was therefore undertaken in January 1998.

2.1 Oxide Thickness Survey

A steam side oxide thickness survey was undertaken on final stage superheater elements in order to determine the magnitude and extent of any overheating damage. Measurements were taken at two locations on each tube; one on the 9Cr material at the outlet header stub bend (at the failure location) and also on 9Cr material within the convection pass just prior to a material transition to Gr 347 stainless steel.

The initial oxide thickness survey, taken at the stubs on the outlet header, indicated that the thickest oxide was on the failed and swollen upper bends with measurements of ~420 and ~380 µm (16.5 and 14.9 mil) respectively. These were the stubs with. There were, however, many other tubes with oxide thicknesses in the order of ~300 µm (11.8 mil). This suggested that the problem was not isolated to the two removed circuits alone. The oxide thickness results are summarised in Figure 5 as a function of both row number and element number.

2.2 Flash Butt Welds

Using the results of the oxide thickness survey, those tubes that had been operating at temperatures above design were identified and their respective flash butt welds removed. A total of seventeen flash butt welds, in addition to the original two, were removed and inspected. Without exception, all of these welds displayed excessive internal upset as seen in the failed and swollen tube. The internal projected area of the tubes at the flash butt welds varied from 118 to 201 mm^2 (0.183 – 0.312 $inch^2$) compared to the 360 mm^2 (0.558 $inch^2$) internal area of the 1Cr-0.5Mo steel stubs. The projected areas are plotted as a function of element number in Figure 6.

A metallographic section was prepared through the flash butt weld from the failed circuit. The section appeared to comprise the main weld in the middle, but had additional protrusions at the top and bottom which penetrated further into the tube bore. Analysis using the scanning electron microscope confirmed that the parent tubes on either side of the flash butt weld were 1Cr-0.5Mo and 2.25Cr-1Mo

as specified. The weld metal and protrusions had composition between 1Cr-0.5Mo and 2.25Cr-1Mo steel [2], as would be expected if they had been produced from the molten metal during the flash butt welding process.

2.3 Foreign Material

During inspection of the header and removal of the selected flash butt welds, further foreign objects were found in three circuits. One of the objects was lodged firmly in the flash butt weld and the others were loose in the tube upstream of the weld. A photograph of the foreign object lodged in one of the tubes is shown in shown in Figure 7.

The appearance of the objects was consistent with them having been weld deposits as there was a clear indication of weld chevrons on one side of the material. An additional object was removed from one of the inlet headers. This piece was not analysed, but was consistent in appearance with the others found. Sections taken through the objects were mounted metallographically and examined in the SEM to enable EDXS analysis of the composition of the objects. The EDXS analysis indicated that all of the objects were nickel-rich (~73 wt % Ni, ~12% Cr, ~10% Fe and ~5% Si) [2].

Typical pieces of “foreign material” located in steam inlet headers during further inspections are shown in Figure 8.

3. DISCUSSION

3.1 Flash Butt Welds

Flash butt welding was used for the construction of the final stage superheater inlet tubing as it is a relatively cheap, quick method of undertaking repetitive tube welds. At the time of boiler construction the applicable codes (Australian Standard AS CB15, Part V) were somewhat limited in relation to the requirements for flash butt welds when compared to the requirements for other types of weld. This code simply required that the amount of weld upset (both internal and external) should not exceed that determined during weld qualification or the requirements of the purchaser. From the observations detailed above it is clear that weld variables were not adequately controlled, nor were post weld inspections adequate. It is worth noting that the welds in the same location on the second Loy Yang B boiler were also inspected and found to be more satisfactory.

The excessive internal upset observed effectively formed an orifice plate within the inlet tubes. The pressure drop subsequently created by this “orifice” was estimated to reduce the steam flow in the tubes by up to 25% with a resultant increase in tube metal temperatures of up to 22°C (71.6^{o}F)[3]. While this increase was insufficient to cause the failures seen, it was sufficient to cause concern that the life of header stub tubes could be reduced below their design intent.

3.2 Remaining Life

The steam side oxide thickness data collected was used to assess the effective operating temperature of the tubing over its operating life and subsequently, its remaining life. Algorithms contained in EPRI Tubelife III [4] were used for this purpose. However, preliminary attempts to estimate the effective operating temperatures of the 9Cr-1Mo stubs at the outlet header, and the 9Cr-1Mo steel tubes just before the transition to 347 stainless steel, produced temperatures that were much too high.

Using oxide data collected from points with a known operating temperature history (some tube metal thermocouples are permanently installed) an attempt was made to correlate the measured data to the Tubelife III algorithms. Figure 9 shows the expected oxide thickness as a function of temperature, based on the these algorithms, together with the measured data. As can be seen, there is reasonable correlation between the algorithm (with an oxidation potential of 85%) and the measured data up until a temperature of approximately 540°C (1004°F) and an oxide thickness of approximately 140μm

(5.51 mil). At temperatures above this there is a rapid increase in the thickness of oxide observed.

Metallographic examinations of the failed and swollen tubes indicated that there is a change in the nature of the steam-side oxide scale along the 9Cr-1Mo steel tube circuits. At the higher temperature locations, it appears that an oxide spinel layer forms and becomes a significant proportion of the total oxide thickness observed [1,2]. It is likely that this change in mechanism of the dominant oxide formation is responsible for the “dog leg” observed in Figure 9. Based on the data in this figure a linear relationship was approximated that provided an upper bound estimate of temperature as a function of oxide thickness. The line was defined as $T = 528 + 0.103\ tox$ [1,2], where temperature and oxide thickness are in °C and µm respectively (Note: this in an empirical relation that can only be used for this particular circumstance).

The Tubelife III algortihms were therefore used to determine the effective operating temperatures for oxide thicknesses < 140µm and the function defined above used to determine the effective operating temperatures for oxide thicknesses > 140µm.

Using this data, together with creep properties for 9Cr1Mo steel from PD 6525 [5], a lower bound creep life estimate of 260,000 hours was determined. Accelerated creep rupture testing of the “as installed” 9Cr tube material found that the creep properties were actually far superior to those specified in PD 6525. It can therefore be concluded that the remaining creep life of the final stage superheater tubing has not been significantly affected by the excessive internal upset of the flash butt welds.

3.3 Foreign Material

Although the excessive upset metal at the flash butt welds appears to have affected the steam flow distribution within the final stage superheater circuits, this alone did not account for the failures experienced which would have required significantly higher temperatures. The root cause of the failures was determined to be the pieces of foreign material becoming lodged in the weld upset creating an additional and significant flow restriction. Further inspections also found similar foreign material in superheater inlet headers and also in main steam strainers located on the turbine inlet, with analysis confirming the material to be of the same Nickel rich composition.

A search of system drawings revealed that the only location from which this material could be originating was the steam temperature attemperators. These attemperators include a thermal liner to protect the main pipe wall from high thermal gradients, potentially created when attemperating spray water is applied. The liners are held concentrically within the pipe by a series of bearing screws which locate against patches (50mm x 50mm) of Nickel hardfacing (Figure 10). Nickel hardfacing was also applied to the tip of the bearing screws. In both cases the hardfacing material was applied using a MMAW process and hand ground to the required profile. For the pads on the liner a buttering layer of 1Cr-0.5 Mo material was first applied.

Each attemperator had eight such patches and there are sixteen attemperators within the superheat/reheat circuit (ie: a total of 128 pads). Boroscopic inspections of the attemperator liner on the inlet to the final stage superheater confirmed that hardfacing material was being lost from these locations. As can be seen in Figure 11a and 11b, the hardfacing was literally breaking away. Future metallurgical inspections of these pads found that there was little evidence of fusion between the hardfacing and the buttering layer and that delamination was most likely occurring due to thermal stresses created in the layer during operation of the attemperator.

The relationship between the delamination of this material and thermal stress was further observed while analysing temperature data. During a boiler shut down in early 1998, thermocouples were installed on a large number of stub tubes at the outlet of the final stage superheater. Assessment of data collected from these thermocouples during subsequent operations showed that step increases in some stub temperatures were occurring during boiler run-ups (Figure 12).

These increases correlated with the initial opening of attemperator spray-water valves. It is believed that during the initial stages of a boiler run-up low steam flows do not enable effective atomisation and mixing of spray-water with the steam. As such there is a greater propensity for liquid/vapour to impact on the thermal liner with associated rapid cooling. The subsequent thermal stresses resulted in delamination of the hardfacing material which was then carried by the steam flow through the circuit until it either settled in the inlet header, travelled in to the main steam line and was captured in the main steam strainer or, in some instances, became lodged in the internal weld upset of the flash butt welds. When this occurred the rapid increase in tube metal temperatures were observed.

4. REPAIRS

4.1 Flash Butt Welds

There were 396 flash butt welds on the final stage superheater inlet tubing on each boiler. During initial investigation and repairs these were replaced by simply cutting out a short section of tube incorporating the flash butt weld and installing a new spool piece. However, it was found that there was sufficient flexibility within the tube loops to enable a single cut to be made through the flash butt weld and the existing weld metal removed as part of preparation for a single V-butt weld.

All unit 1 welds were replaced by the end of 2001. While the Unit 2 flash butt weld internal upset was not as severe as Unit 1, the decision was also taken to remove the unit 2 welds. This was undertaken in 2003. Removal of the flash butt welds resulted in a noticeable downward shift in operating temperatures as can be seen in Figure 13.

4.2 Attemperator Thermal Liners

Due to the amount of nickel hardfacing within the system and the failure mechanism present, there was a high likelihood that delamination would continue, resulting in further tube failures. Even with the flash butt welds removed there were still other locations where it was considered this material could become lodged. In addition, as the pads disintegrated the liners themselves would become loose, increasing the probability of fatigue failure at the liner anchor points. The decision was therefore taken to remove the bearing pads from all attemperator liners and replace all the bearing screws. Discussion with Engineering personnel, including OEM representatives, indicated that this should not adversely affect the integrity of the liners.

The initial preference was for each complete attemperator assembly to be removed from its respective steam pipeline. This would have enabled the attemperator to be disassembled in a workshop environment and the hardfacing removed. However, it was found that this was only practical for two of the 16 locations on each boiler. An alternative means of accessing the liners therefore had to be developed. The attemperator barrels ranged in size from 306mm OD (12”) to 521mm OD (20.5”) and 32-42mm (1.26” – 1.65”)wall thickness. Barrel materials were 1Cr-0.5Mo and 0.5Cr-0.5Mo-0.25V.

Following discussions with maintenance contractors and design and welding engineers, it was decided to remove a section of the attemperator barrel adjacent to each set of hardfaced pads (two rows per attemperator) while leaving the liner itself in place. This was achieved by performing two circumferential and two longitudinal cuts at each location, with the barrel section then being removed in two half segments (Figure 14a). The circumferential cuts were undertaken using a pneumatically driven “clam shell” lathe while the longitudinal cuts were completed with a cutting disc. Once the segments were removed, the liner together with the nickel pads were exposed (Figure 14b) with the hardfacing subsequently being removed by the use of hand grinding tools. A chemical etch was used to verify that complete removal of hardfacing had been achieved.

Once each of the segments were removed they were sent to the workshop for machining of weld preparations. Due to material loss during cutting, each of the longitudinal faces required material build

up by MMAW prior to machining in order to obtain the required root gap. Matching segments were then set up in a jig for dimensional checks and final machining.

Reinstatement of the segments was undertaken utilising strict quality control. The segment set-up was verified prior to commencement of welding and all GTAW root runs were independently inspected, including a hot magnetic particle inspection. Fill and capping runs were performed using MMAW. All welds were fully inspected using ultrasonic techniques.

All nickel hardfacing material has now been successfully removed from the steam attemperators with Unit 1 being completed in 2001 and Unit 2 in 2003.

5. CONCLUSIONS

Following tube failures in the final stage superheater it was found that excessive internal upset was present at flash butt welds located in the superheater inlet tubing. Metallurgical assessment of tubing removed from the boiler, together with information obtained from steam side oxide thickness surveys, found that in general this excessive upset had resulted in reduced steam flow and increased tube metal temperatures. While oxide growth kinetics differed from that predicted by algorithms a relationship was able to be defined by correlating oxide thickness at locations of known temperature. Using this relationship an estimation of effective operating temperatures was able to be made and a remaining life assessment performed. This showed that there had been no significant impact on the life of the superheater elements.

Of greater impact however, and the root cause of the failures experienced, was the fact that the internal upset at the flash butt welds was “trapping” pieces of foreign material and causing severe tube blockages. The foreign material was subsequently determined to be nickel hardfacing originating from the thermal liners in steam temperature attemperators. The hardfacing material was delaminating due to a combination of poor weld fusion and thermal stresses created during operation of attemperators, particularly during boiler start-ups.

Subsequently all flash butt welds on final stage superheater inlet tubing were removed with a resultant reduction in effective tube metal temperatures. All nickel hardfacing was successfully removed following the development of a process, whereby segments of attemperator barrel were removed to provide in-situ access to the thermal liners on which the hardfacing was located.

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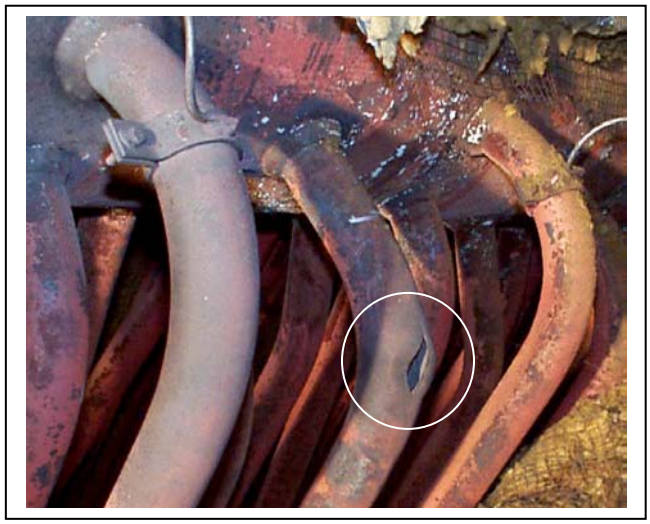

Figure 1 : Tube rupture at 9Cr-0.5Mo outlet bend.

Figure 2 : Swollen outlet bend on tube adjacent to failure.

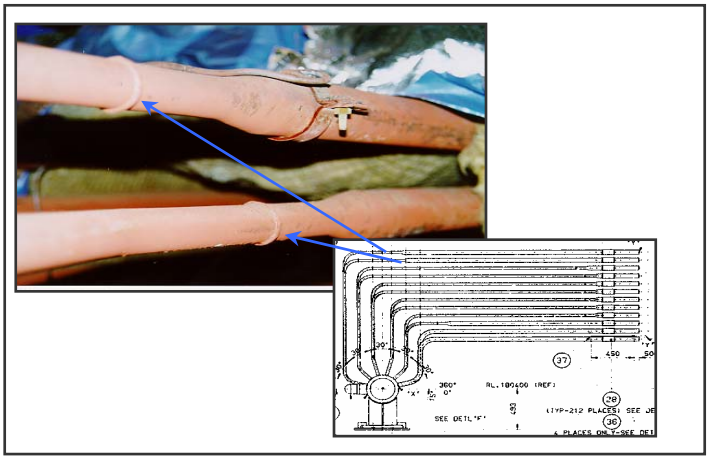

Figure 3 : Diagram showing location of flash butt welds in superheater 4 inlet tubing.

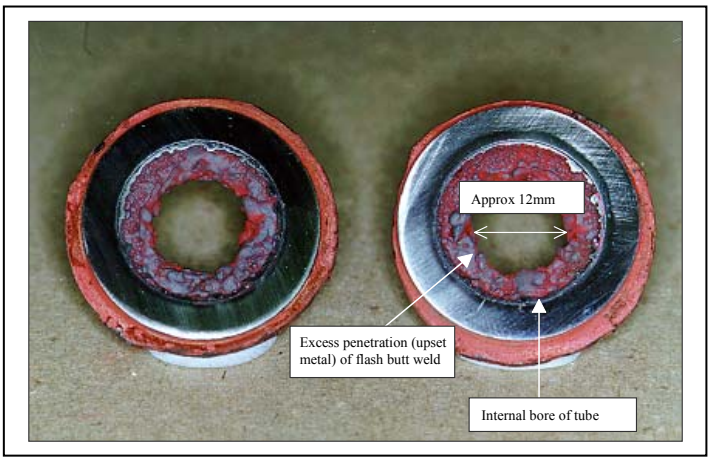

Figure 4 : Cross section of inlet tube flash butt welds removed from Superheater 4 inlet tubing showing excessive internal weld upset.

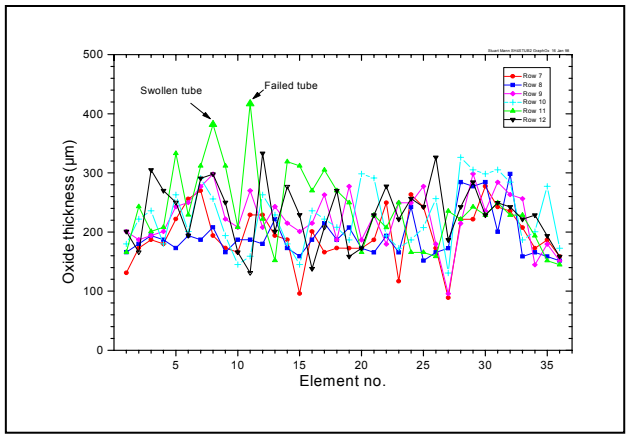

Figure 5 : Plots of steam side oxide thickness as a function of element number.

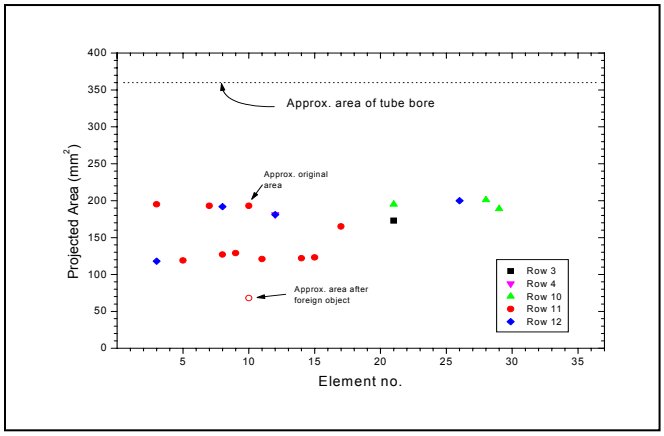

Figure 6 : Plot of the projected area of the 'orifice' at the flash butt welds examined, as a function of element number

Figure 7 : Piece of "foreign material" lodged in the internal upset of the flash butt weld.

Figure 8 : Pieces of foreign material removed from Superheater 4 Inlet header.
(Note: Ruler units are inches)

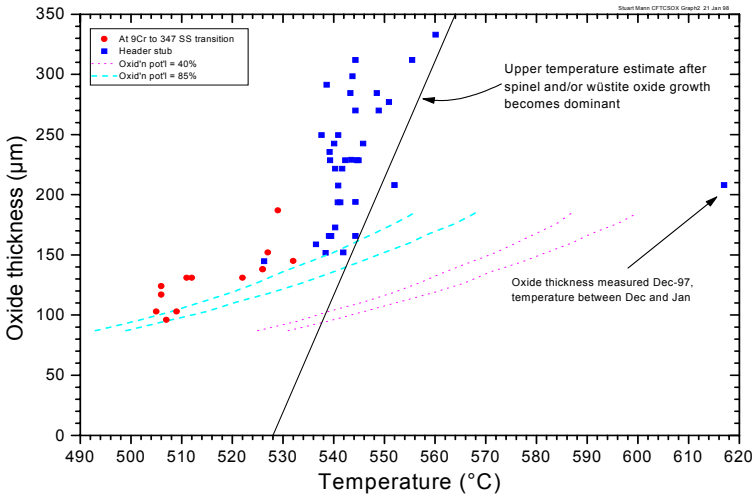

Figure 9 : Relationship between oxide thickness and effective temperature.

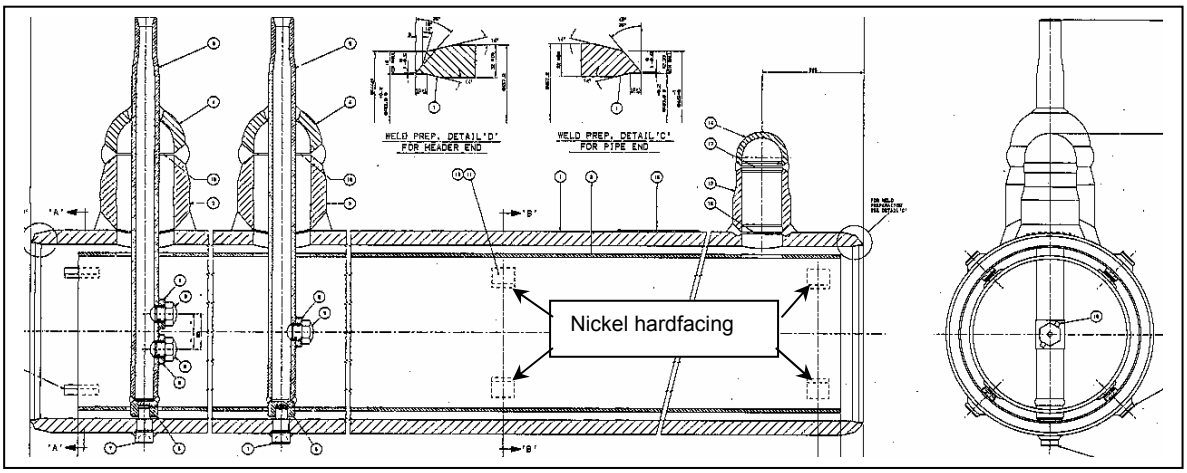

Figure 10 : Arrangement of steam temperature attemperator showing location of Nickel hardfaced bearing pads.

Figure 11(a) : Nickel hardfaced pad showing area breaking away (left hand corner).

Figure 11(b) : Plan view of Nickel hardfaced pad showing area breaking away.

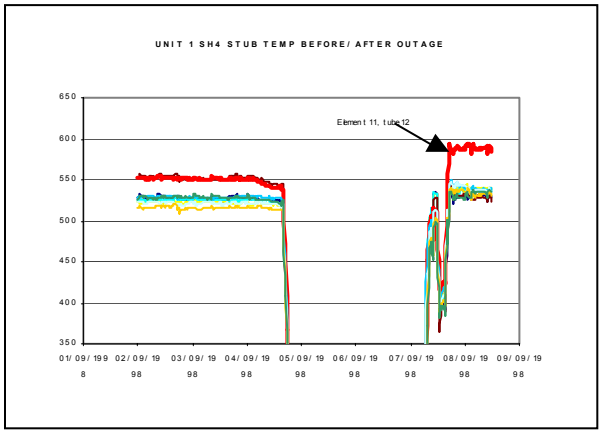

Figure 12 : Increase in tube metal temperature during boiler start up as hardfacing breaks off and lodges in flash butt weld.

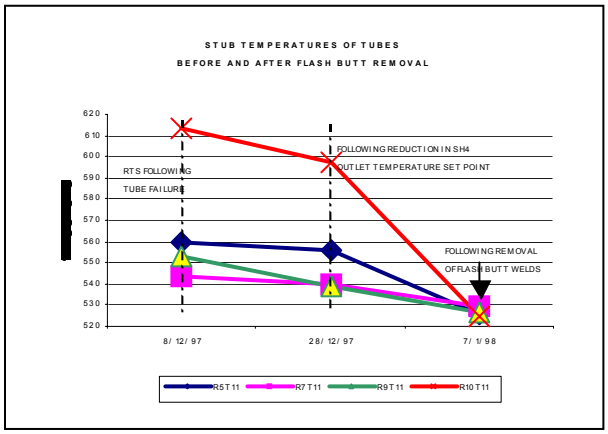

Figure 13 : Typical reduction in operating temperatures following removal of flash butt welds.

Figure 14 (a) : View of attemperator barrel showing circumferential and axial cuts for removal of barrel segments.

Figure 14 (b) : View of attemperator with barrel segments removed for access to nickel hardfacing on liner.

SESSION 7: HRSG Tube Failures (HTFs)

Chairman: B. Dooley, EPRI

Quantifying Thermal Transients in Heat Recovery Steam Generators

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1 Introduction

Many papers and reports have been published by the authors of this paper and by others during the past several years to draw attention to some undesirable features commonly used by Heat Recovery Steam Generator (HRSG) and balance of plant designers for HRSG pressure parts and critical auxiliaries, respectively. This includes certain aspects of widely used operating practices for combined cycle unit starts and shutdowns that are particularly damaging to the HRSG. Although some progress has been made to address some of the concerns previously raised, there remains skepticism by some who choose to take the position that the concerns have been overstated.

The more recent papers and reports referenced in this paper included quantitative data to support the previously expressed concerns. This paper provides further evidence, selected from extensive tube temperature measurements made on the final reheater of an “F-class” HRSG, of the severity of the temperature differences and associated thermal-mechanical forces and stresses that transiently occur during combustion turbine (CT)/HRSG starts and shutdowns, and also during certain on-load operating conditions.

2 Reheater 2 Arrangement

The final reheater (RH2) is located at the inlet of the HRSG heat transfer section and exposed directly to the exhaust gas from a 7FA CT, Figure 1. In direction of gas flow, the final heating section of the high pressure superheater (HPSH) is immediately behind RH2, followed then by the primary reheater section (RH1).

RH2 comprises two rows of parallel-pass tubes, both rows connected to the same lower inlet and upper outlet headers; Figure 2 is the view from the gas inlet side of RH2 looking towards the HRSG stack. The gas inlet, or front, row 1 tubes are straight tubes connected at 12:00 and 6:00 o'clock, respectively, to the bottom inlet and top outlet headers. The rear, row 2 tubes, which are arranged directly in line with those of the preceding front row tubes in the direction of gas flow, each incorporate a bend at each tube end to connect the tube to the same top and bottom headers.

The headers and tubes of RH2 are top supported by fixed supports attached to the upper headers. Thermal expansion of the tubes when heated during operation is accommodated by downward expansion of the RH2 tubes and lower headers in conjunction with some distortion of the tubes to accommodate differences in thermal expansion between row 1 and row 2 tubes that occurs throughout both stable and unstable operation.

Row 1 and row 2 each have 66 tubes divided equally between the two bundles. Each of the two lower headers has two inlet pipe branches opposite tubes #9 and # 25 in the left hand bundle and tubes #42 and #58 in the right hand bundle. The two upper outlet headers also each have two outlet pipe branches positioned opposite the same tubes as the lower header pipe branches.

Steam is transferred from four pipes, two on each RH1 bottom outlet header, through a horizontal "U" shaped manifold to which are connected the four inlet pipes, two connected to each of the two lower inlet headers of RH2, Figure 3. The reheater (RH) desuperheater spraywater injection

nozzle is located immediately downstream of and less than 1 pipe diameter from the outlet of the second 90° small radius bend of the "U" manifold pipe. The first branch to RH2 inlet on the manifold is located only about 7 pipe diameters downstream of the desuperheater nozzle.

The U manifold has three drain connections, one at each of the two blind ends and the third in the short straight spool between the two 90° bends. The manifold was installed horizontally, without any slope, when cold. While in this condition it has no fall towards the drain connections, such that condensate will pool along the bottom of the long length of manifold between the drains. When tubes are hot, and during transient heating of the tubes at startup, the RH2 tubes expand downwards further than those of RH1, and so any condensate that collects in the bottom of the manifold connected to the RH1 outlet pipes will tend to flow towards the RH2 section of the U manifold.

RH and HPSH drains are all connected to the same blowdown vessel. Although the blowdown tank is in a pit intended to provide gravity drainage of condensate, in practice there is inadequate static head to quickly drive RH drains into the blowdown tank when there is no pressure in the RH. Furthermore when HPSH and RH drains are both in operation, as they should be throughout the prestart purge, the large drain flow from the HPSH may raise the pressure in the blowdown vessel above that in the RH, in which case there is a risk of reverse flow in the RH drains and of blowing slugs of condensate from the blowdown vessel into the RH manifold, lower headers and selectively through some tubes to the top outlet headers.

3.0 Potential Cyclic Life Problems for RH2

The arrangement of tubes, headers and interconnecting pipes and RH desuperheater in the subject HRSG incorporates several design features that have been highlighted in previous papers and reports by the authors and others as sources of potentially high thermal-mechanical stresses induced by significant temperature differences between the individual tubes of RH2. (References 1, 2, 3, 4, 5 and 6).

The material damage mechanism of principle concern in RH2 is creep fatigue. Tube temperature differences that transiently develop localized inelastic strains at the toe of tube-to-header attachment welds expend a proportion of the fatigue life of the material during each thermal cycle, Where the material experiences significant creep at the high temperature dwell part of the thermal cycle (on-load operation), as is the case in RH2, then later during on-load operation creep relaxation of the residual stresses resulting from localized plastic deformation during the high strain parts of the thermal cycle (startup and shutdown) substantially increases, possibly by a factor as high as 10, the life expended by each thermal cycle.

To obtain reliable data on RH2 tube and header temperature transients during startups, shutdowns and on-load operation of the CT and HRSG, approximately 100 tube thermocouples (TC) were spot welded to the unfinned area of selected tubes near the tube-to-header welds of RH2, Figure 4. TCs were installed at the top and bottom of a proportion of both front and rear row tubes. TCs were also installed on the outside surface of the outlet header. Care was taken to avoid spot welding on tube bends or directly adjacent to welds. The TCs were located behind gas baffles where gas convection effects are small. Where access permitted tube and TC were also wrapped with insulation to eliminate the possibility of any gas temperature influence and ensure that the TCs accurately recorded the tube metal temperatures.

3.1 The influence of pressure parts design choices on the severity of transient thermal mechanical stresses at tube attachment welds to headers.

During stable operation under most operating conditions, all tubes in HPSH and RH of many designs of HRSG usually operate with closely similar mean tube temperatures and with tube ends at similar temperature to the header to which they are attached. Under the foregoing conditions, thermal mechanical stresses in tubes and headers are innocuous.

However, TCs installed on many tubes of HPSH and RH of several different designs of HRSG have highlighted that very significant transient temperature differences between tubes, also between tubes and headers, often occur during CT starts, shutdowns and in some instances during on-load operation.

Three mechanisms, each of which develop significant restrained thermal gradients and damaging thermal stresses, have been highlighted by the TCs installed on the tubes and headers of the subject RH2:

(i) Transiently high row 1 to row 2 tube temperature differences during every CT start that develop thermal-mechanical axial forces in all tubes because both rows of tubes are attached to the same top and bottom headers; (refer to sections 3.2.1 and 3.2.2, below).

(ii) Transiently high tube to header temperature differences during every CT start and shutdown; (refer to section 3.3, below).

(iii) Selective chilling, in some cases severe quenching, of a proportion of the tubes by condensate of different origins; (refer to section 3.4, below).

All three mechanisms develop peak thermal stresses at the same position on the tube outer surface at the toe of the tube-to-header attachment welds and thus their damaging effects are additive. The first two mechanisms occur simultaneously and thus increase the cyclic stress range, which may substantially increases the life expenditure per cycle.

The magnitude of the transient peak temperature differences that develop thermal stresses by mechanisms (i) and (ii) can be predicted with more certainty from TC data than can the temperature differences developed via mechanism (iii). Tube and header temperature transients, and the associated thermal stresses, caused by mechanisms (i) and (ii) are strongly related to the HRSG arrangement of RH and HPSH sections, by the thickness of headers, by the CT exhaust gas temperature characteristic during acceleration and operation of the CT at minimum CT load, by the HP drum pressure prior to the start, and by the operating procedure utilized during the initial part of the CT/HRSG start. The third mechanism, tube-to-tube temperature differences caused by chilling via condensate migration, is the most difficult to detect. This is due to its being unit specific because it is strongly influenced by the design and arrangement of RH and HPSH drains, attemperators, operating and maintenance practices, etc, and can only be quantified on any particular HRSG installation by attaching TCs to many judiciously selected tubes.

Previous papers have discussed more fully the first two mechanisms and provided more extensive data from the subject RH2 and from the HPSH and RH of other designs of HRSG, References 1, 2, 3, 4, 5, and 6. In order to emphasize the importance of addressing all potential sources of cyclic damage to RH2 of concern with the subject RH2, the first two mechanisms have also been included in this paper together with a portion of the more extensive quantitative temperature data provided in References 3 and 6.

However, it is the new data published in this paper related to condensate migration that is of greatest concern because it highlights that selective, transiently random, chilling or quenching of a proportion of tubes in a bundle can develop very severe temperature differences between adjacent tubes, which cannot be detected or quantified, unless many TCs are attached to many of the RH and HPSH tubes. Therefore, it is crucially important to identify all of the potential sources of condensate in RH and HPSH of all designs of HRSG and eliminate these sources from new designs and implement modifications on installed units that mitigate the more damaging sources.

3.2.1 Panels with parallel-pass tube rows and shared headers are susceptible to high thermal-mechanical stresses

Whenever row 1 tubes operate with a higher temperature than the row 2 tubes, then the larger thermal expansion of the row 1 tubes is resisted by the lesser expansion of row 2 tubes, resulting

in compressive thermal mechanical forces in the hotter row 1 tubes and tensile forces in the somewhat cooler row 2 tubes, Figure 5. Likewise, when the presence of condensate fleetingly and selectively chills one or more tubes below the temperature of the majority of the other tubes in both tube rows, the transiently chilled tubes experience large tensile forces.

When two or more rows of tubes are attached to the same upper and lower headers, it is inevitable that one or more tubes are offset from the vertical centerline of one or both headers and connected to the header by a bend, Figure 5. The bending moment at the weld attaching each offset tube to the header, caused by thermally induced forces in the tubes whenever the entire tube row or individually chilled tubes operate at different temperatures, substantially increases the peak thermally induced stress above that which results from the direct thermally-induced force applied by a straight tube to the header. It has been suggested by others that the headers may rotate in response to temperature differences between rows, thereby reducing stresses at the weld. While this may, to a limited extent, be true in some cases where only small bore drains are attached to the lower header, it is not so in this case due to the substantial rigidity of the RH1 to RH2 interconnecting piping restraining rotation of the lower headers.

3.2.2 Rows 1 to row 2 tube temperature differences during startups

RH2 has two tube rows attached to the same upper and lower headers. Row 1 tubes are straight and the row 2 tubes have a bend at each end to connect the tubes to the headers, Figure 2.
When operating at baseload, the average temperature of row 1 tubes is of the order of 10°F higher than that of row 2 tubes. This difference in average temperature between row 1 and row 2 tubes increases to of the order of 20 to 25°F when operating the CT at part loads between 85 to 125MW, which is probably too small to be a fatigue concern, even conservatively assuming a stress intensification factor of 4 or 5 from the bending moment in the offset row 2 tubes. However, significantly larger temperature differences develop between row 1 and row 2 tubes at every CT startup during acceleration of the CT to speed and initial loading.

Figure 6 plots the individual tube temperatures of RH2 row 1 and row 2 tubes measured just below the outlet header during a startup on 1-12-03 using CT Exhaust Gas Temperature Matching (ETM), which limits the CT exhaust gas temperature when operating at minimum CT load to a little over 700°F. The tubes develop a large spread in temperature during the final stages of acceleration to speed and synchronizing of the CT generator. Prior to about 28 minutes on the time axis of Figures 6, there was no steam flow through the RH. Thus the finned row 1 tubes closely followed the rapid increase in CT exhaust gas temperature during acceleration of the CT to speed and after initial loading of the CT. Some of the heat in the CT exhaust gas is removed in the row 1 tubes, thereby lowering the gas temperature into row 2 tubes and thus also of the row 2 tubes, which therefore lag behind the row 1 tubes during the initial phase of the CT/HRSG startup.

Figure 7 utilizes the same tube temperature versus. time data as Figure 6, but has averaged the row 1 and row 2 tube outlet temperatures. The maximum difference in average temperature of row 1 and row 2 tubes reaches about 150°F, which is a significant concern for the offset row 2 tubes. Furthermore, the peak thermal stresses developed in the row 2 tubes at their attachment welds to the headers, by the row 1 to row 2 tube temperature difference of about 150°F, is significantly increased by an additional transient thermal stress developed simultaneously by high tube-to-header temperature differences during every CT startup; (refer to section 3.3, below).

3.3 Tube-to-header temperature differences at tube attachment welds during startups

During every startup, the finned RH2 tubes shadow the rapid rise in CT exhaust gas temperature much more closely than the thicker headers to which they are attached, causing the tubes to expand thermally in diameter relative to the hole in the header to which they are welded, Figure 8.

The initial rate of tube temperature rise is similar at every startup because cooling steam flow through the RH cannot be established until after the HP bypass has opened later in the start and the CT produces a similar exhaust gas temperature versus time characteristic during the acceleration phase to synchronous speed at each startup, at least up to the point where the generator is synchronized. However the rate of heating of the headers, and thus the peak difference in temperature between tubes and header wall in proximity to the tubeholes, is strongly influenced by the thickness of the headers, which are heated predominantly by condensation on their inner surfaces and by conduction from the comparatively thin tubes.

Figure 9 plots the tube temperature data measured at the outlet of RH2 tubes during the 1-12-03 startup, together with the outer surface temperature measured on headers of different thickness in the hottest sections of the HPSH and RH. The thicknesses of HPSH and RH2 outlet headers are 2.0" and 1.2", respectively, while the lower return header of HPSH is about 0.7" thick.

Figure 9 illustrates the substantial influence of header thickness on the magnitude of peak tube-to-header temperature difference during startups. Further measured data quantifying the influence of header thickness on tube to header temperature differences during startups from various initial conditions, for different CT exhaust gas characteristics and also during shutdowns using different procedures are provided in References 3 and 6.

During each start, the sharp change in temperature between tube and header develops a compressive bending stress and hoop stress at the tube surface at the toe of the attachment weld to the header that on row 2 tubes is additive to the peak transient thermally-induced compressive bending stress developed by the row 1 to row 2 average tube temperature difference discussed in sections 3.2.1 and 3.2.2, above. Sophisticated analytical modeling supported by data from cordal thermocouples judiciously placed in a header close to tubeholes, both beyond the scope of this paper, would be required to quantify the peak compressive stress developed on the surface of the row 2 tubes by these two thermally induced loading mechanisms that occur simultaneously at every startup. Without the results of such work, the prudent action recommended for horizontal gas path HRSGs intended for even limited cycling service is to exclude the possibility of damaging thermal stresses caused by tube row to row temperature differences by precluding the use of multiple rows of tubes that share the same top and bottom headers. Likewise, limiting the maximum thickness of higher temperature headers to about 1 inch reduces the tube to header temperature difference and associated thermal stress substantially such that extensive cycling should not be a concern.

Since it is the cycle stress range that determines cyclic life, the prediction of cycles to crack initiation requires determination also of the magnitude of the peak thermally-induced tensile stress at the same location on the row 2 tube attachment welds, which occurs during the shutdown part of each thermal cycle. The latter are strongly influenced by the method used for normal shutdown of the CT/HRSG block. More extensive quantitative data and discussion related to transient tube-to-header temperature differences are provided in References 3 and 6.

3.4 Damage caused by the unintended presence of migrating condensate in the reheater during startups, shutdowns and onload operation

The unintended presence of condensate in RH and HPSH of HRSGs is difficult to detect without TCs attached to tubes. The magnitude of peak tube-to-tube temperature differences can vary widely and is impossible to quantify without installing thermocouples on a significant proportion of tubes in the most susceptible sections of the HRSG.

3.4.1 Condensate migration in RH2 during startup

Figure 10 plots the temperature measured at the top of every tube installed with a TC at their outlet just below the top outlet header during a cold HRSG start performed with the CT in ETM

mode on 1-12-03. Steam flow was established through the reheater at about 28 minutes on Figure 10 and the introduction of pressure drop through the RH2 caused large quantities of condensate in lower manifold pipes and headers to be displaced forward through some of the tubes and into the RH2 outlet header.

Most of the condensate was displaced through the row 1 tubes as only three tubes of row 2 indicated sharp temperature drops at tube outlet when condensate migration occurred. However it was evident, (from other TC data not presented here), that condensate was present at the bottom of both row 1 and row 2 tubes during the same period.

To better appreciate the behavior of the condensate through the period when it was being blown forward, "Time Slice Data" (TSD) was prepared. Figure 11 is a typical TSD plot. Each TSD page plots on an arrangement drawing of RH2 tubes all RH2 tube temperatures measured by TC within the same time span of less than 5 seconds of each other by tube number, row number and position at top or bottom of tube, and plots each recorded temperature. Also highlighted on the RH2 tube & header symbolic arrangement drawing are the positions, relative to the numbered tubes, of the inlet and outlet pipe branches on the bottom inlet and top outlet headers, respectively, and the position of blind ends of each header.

Sequences of consecutive TSD plots were assembled at short time interval gaps for those periods when there was considerable instability or fluctuation in tube temperatures. For the period during the event plotted in Figure 10 when condensate was blown forward, 32 different TSD plots between 08:53 and 09:05 on 1-12-03 were assembled.

Figure 12 incorporates 6 of the sequenced 32 TSD plots for this start event to illustrate the large and rapid tube temperature fluctuations that occur when intermittently heated by gas and then chilled by slugs of condensate. Points for consideration relevant to Figs 10, 11and 12 are:

- The CT was synchronized and loaded to about 17MW at 08:44 hours; CT exhaust gas temperature was fixed and stable at about 700°F for several minutes before steam flow commenced through RH2.
- Prior to establishing a cooling steam flow through the RH2 tubes, the temperatures recorded at the top and bottom of rows 1 & 2 tubes align in general with reasonable expectations; i.e., row 1 tube top temperatures somewhat higher than and row 2 tube top temperatures and similarly row 1 tube bottom temperatures are generally above row 2 bottom temperature.
- Steam flow was established through the RH when the HRH steam dump control valve was opened between 08.53:30 and 08.53:45. The HRH steam startup vent remained closed throughout the startup
- Condensate blown up through tubes was most evident in the tubes closer to each of the four inlet pipe branches on the inlet header. Condensate blowing forward is initially evident at 08.53:45 through row 2 tubes 41, 42 and 43 opposite the 2nd RH2 inlet pipe branch downstream of the desuperheater and row 1 tube 53 opposite the 1st pipe branch after the desuperheater. By 08.54:00, (Figure 12), condensate was commencing to lower the bottom temperature of row 2 tubes 24 and 25 opposite the 3rd pipe branch. By 008.54:15, (Figure 12), condensate first became evident in tube 10 of row 2 and 15 seconds later tubes 7 to 11, opposite the 4th pipe branch from the blind end of the reheater interconnecting manifold, were at or close to saturation temperature either at their top or bottom TC.

Substantial quantities of condensate were blown forward over a period lasting more than 5 minutes. At some time points during the migration of condensate the temperature at the top of some tubes was chilled by up to 430°F below the other tubes which remained close to the gas temperature of about 700°F The average of top and bottom temperatures in some of the tubes chilled at bottom and top by condensate was transiently more than 300°F below that of adjacent tubes that remained free of condensate slugs. This develops very damaging thermal stresses, particularly at the weld attaching the offset row 2 tubes to the headers.

3.4.2 Gross condensate migration in RH2 during a warm restart

Figure 13 contains six TSD plots from a warm start from an initial HP drum pressure of 320psig on 3-13-03 using CT ETM with a setpoint for exhaust gas of 750°F when at CT minimum load.

CT firing commenced at 21.32. HPSH and RH drains were cycled open and closed several times between 21:32 and 21:38. The HP startup vent was cracked open throughout startup and the HRH startup vent was 20% open from 21:33 to 22:04. The HP bypass inlet pressure control valve (PCV) opened at 21.41:30 when HP pressure reached about 350psig. The HRH bypass PCV opened between 21.45:30 and 21.46:00 when the RH outlet pressure reached 150psig.

Immediately after the HRH bypass PCV opened and steam flow was established through the RH, condensate was blown through RH2 tubes for a period of about 10 minutes, Figure 13. Substantial quantities of condensate, initially sub-cooled, progressively flooded all tubes, commencing with tubes supplied by the 1st inlet pipe, then those supplied by 2nd, then 3rd and finally the 4th inlet pipe. Prior to this quenching incident, the top of tubes ranged between 700°F and 800°F. However, between 21.48:00 and 21.48:15 every top and bottom tube with a TC was between 340 and 400°F. During the incident, the temperature gradient in the ligament between some adjacent tubeholes through the outlet header was more than 400°F. In addition the average of top and bottom temperature of many tubes experienced a transient tube-to-tube temperature difference of about 240°F.

Such severely damaging events cannot be detected from normal DCS data and similar condensate quenching incidents have probably occurred on many HRSGs.

In this incident, it is improbable that condensation inside tubes or pipes of the RH was anything more than a minor contributor to the large quantity of condensate that was in the RH for so long after HRH steam flow was established. In tests on this and other HRSGs, three potential sources of condensate carry over into the RH during starts have been identified:

1) Reverse flow in the RH drains and of blowing slugs of condensate from the blowdown vessel into the RH interconnection manifold, lower headers and tubes. HPSH and RH drains need to be open simultaneously during all CT starts. When HPSH and RH drains are disposed to the same blowdown vessel, the large flow of HPSH drains sometimes raises the vessel pressure above RH pressure On most horizontal gas path HRSGs, there is inadequate static head to quickly drive the RH drains into the vessel, even when both RH and blowdown vessel are both at atmospheric pressure.
2) Leakage of attemperator spraywater when intended to be shut off. Interlocks should ensure that the spraywater block valve cannot be opened unless CT exhaust gas temperature is above a minimum setpoint temperature below which desuperheating is never required. Frequent maintenance of attemperator spraywater control and block valves is essential to maintain tight shutoff capability during CT starts and initial loading.
3) Carryover of condensate from cold reheat pipes into RH1; long, large diameter pipes condense substantial quantities of vapor during starts. Inadequate drainage arrangements, such as too small drain lines, reliance on reverse flow of condensate to drain connections against steam flow direction, inadequate static head and/or disposed to the same blowdown vessel as HPSH drains, etc. are all too common. The second source of large amounts of condensate in cold reheat pipes is leakage of HP bypass attemperation spraywater, due to inadequate protective interlocks, malfunction and/or inadequate maintenance to preserve tight shutoff.

All of the foregoing potential causes of severely damaging condensate migration in the RH (and similarly in the HPSH) tubes can be avoided by more diligent design and improved operating and maintenance practices.

3.4.3 Tube temperature differences caused by RH2 attemperator spraywater overspray to below saturation temperature during starts.

A warm restart was executed at about 22:30 on 3-11-03 - less than 1 hour following a trip from 18MW. The RH desuperheater sprayed down to saturation temperature between about 02:21 and 03:05 on 3-12-03 because RH outlet steam temp set point was lowered to about 950°F during the period when the CT was ramped up from 16MW to 100MW and CT exhaust gas temperature raised from about 770°F to 1200°F; Figure14.

There is pressure on the operator to expedite loading of the CT and the raising of pressure during startups to meet the short "out of compliance" time limits set by regulatory permit. It is difficult or impossible for any desuperheater to control steam temperature under these rapidly changing conditions. During this set of events the following conditions occur simultaneously:

- CT exhaust temperature is rising rapidly.
- Steam flow decreases as HP pressure increases since most or all of the evaporation is required to compress the volumes occupied by steam in drum, HPSH tubes and piping.
- The rise in steam temperature through RH1 and RH2 is very high because steam flow is reduced (while raising HP pressure), yet heat input from rapidly increasing CT exhaust gas temperature and flow increases rapidly.
- Additional RH desuperheater spraywater is needed, but the reduced steam flow degrades the RH desuperheater's effectiveness.

Under the above conditions it is not unusual for RH and/or HPSH steam outlet temperature to exceed design limits for a short time. While the outlet header experiences some accelerated creep life consumption, the damage would be insignificant if the duration of the event were kept short, especially when pressure is low.

The subject RH is equipped with an instantaneous high outlet steam temperature trip mandated by the jurisdiction's National Board Inspector. In an effort to avoid this trip the operators are tempted to lower the RH outlet steam temperature set point during the CT load increase transient that takes exhaust gas temperature to its maximum of 1200°F. If the setpoint is lowered too much, an overspray condition is inevitable. Far more damage is done to the RH (and HPSH) by quenching from the overspray event than would be caused if the design RH steam temperature were intermittently exceeded. This is just one example where poorly thought out regulatory limits, (short startup times, overly conservative high steam temperature trips that give no consideration to the much more severely damaging consequences), sometime create a significantly bigger problem than the one being solved. Transients like this one are much better handled by automation that eliminates the need, if not the ability, for the operator to take things into his own hands.

Overspraying, (to about 50°F below RH saturation temperature of about 350°F according to the permanent thermocouple in the RH interconnecting manifold downstream of the desuperheater water injection nozzle) occurred for about 40 minutes, Figure 14

Figure 15 highlights the very poor mixing of the spraywater with steam. A disproportionate amount of desuperheating water travels to the blind end of the manifold and all row 1 and row 2 tubes supplied by steam through the 4th inlet pipe branch at the blind end of the manifold are at about 350°F, which is saturation temperature at the prevailing RH pressure. Some of the tubes supplied with steam from the three preceding pipe branches off the manifold are at saturation temperature, but the majority of those tubes measured are between 100 and 270°F above saturation temperature. The temperature at the outlet of RH2 tubes closest to the desuperheater operate at higher temperature than those supplied by a pipe branch further away from the desuperheater. Some tubes are more than 150°F hotter than other adjacent tubes.

HPSH and RH outlet temperature setpoints should not be lowered significantly below their design value of 1050°F, as it can result in damaging tube-to-tube temperature differences when the resulting outlet temperature from either the HPSH or RH the desuperheater is too close to saturation temperature.

3.4.4 Tube temperature differences caused by RH2 attemperator spraywater overspray to below saturation temperature during CT deloading prior to shutdown.

A similarly severe overspray event was recorded during both the startup and shutdown performed on 3-14-04, (figure 16). Note the sudden drops in RH desuperheater outlet temperature. The steam temperature drop on the left is during startup, similar to that in figure 14, while the steam temperature drop on the right is during shutdown. This overspray event again occurs when the gas turbine load transitions the range below 100 MW in which exhaust temperature is still at the isothermal maximum while the steam flow rate is simultaneously reducing.

The CT was deloaded rapidly from 178MW to about 110MW at 10%/min, followed by a hold of about 20 minutes, followed by another rapid load reduction to 40MW at 10% per minute. Load was then reduced progressively using ETM to maintain a linear fall in CT exhaust gas temperature from about 1200°F to about 700°F over about 60 minutes (about 8.3°F/min).

HRH steam temperature setpoint was maintained throughout the shutdown a few degrees below nominal design temperature of 1050°F. Nevertheless, the deloading at 10%/min from baseload to 110MW, and even more so after the hold at 110MW down to 40MW at 10%/min, caused heavy RH attemperation and unstable desuperheater control (overspray event on right side of Figure 16). Figures 17, 18, 19 and 20, which plot all tube temperatures with a TC for; row 1-top; row 2-top; row 1-bottom; and row 2-bottom, respectively, highlight the very non-uniform distribution and significant tube-to-tube temperature differences.

3.4.5 Incomplete Attemperator Vaporization - Steady State on-load operation

While the previous examples of temperature transients can be avoided by thoughtful design and operation it is often easier said than done. This is due to the difficulty in effectively coordinating the combustion turbine's characteristics, HRSG design, superheater/reheater drain system design, startup time requirements, operating procedures, and last but not least - project cost and schedule. Having said that, the following example of differences in temperatures between tubes during steady state operation should not be encountered with a properly designed and installed attemperator.

Figure 21 presents a TSD plot during full load (179 MW) steady state operation with no RH attemperation. The temperature at the bottom of almost every tube in both RH2 tube rows across the duct width was within +/-5°F of 940°F. Temperature at the top outlet of row 1 tubes ranged between 1035 and 1045°F, and of row 2 tubes between 1020 and 1030F. RH steam outlet header temperature was about 1028°F, which aligns closely with the mean of all RH2 row 1and row 2 tube temperatures. The mean temperature at outlet of row 1 tubes is about 15°F higher than row 2 tubes and the difference in average temperature between row 1 and row 2 tubes is thus about 7.5°F, which is of no concern. Figure 21 demonstrates satisfactory uniform heating across RH2 when it receives steam at a uniform temperature from the interconnecting manifold below, (Figure 3).

Figure 22 presents a TSD plot at 04:00 on 3-12-03 during stable operation at 110MW with HRH header temperature of 1,042°F and desuperheating of about 85°F. The bottom of all tubes supplied by the 3rd and 4th RH2 inlet pipe branches operate very close to 900°F, except for three Row 1 tubes that are about 30°F hotter. The bottom of all tubes supplied from the 1st and 2nd pipe branch downstream of the desuperheater operate at about 745°F and about 845°F, respectively; i.e., respectively about 155°F and 55°F lower than the bottom of the tubes supplied

by the two pipe branches furthest from the desuperheater. The variation in temperature at outlet of tubes supplied by the different inlet pipes is about 20% of the differences measured at the bottom of the tubes.

The most significant differences in the average of top and bottom temperature occur in the RH2 panel assembly supplied by the 1st and 2nd inlet pipes. At 04:00, the average temperature of row 1 and row 2 tubes supplied by the 2nd pipe branch is about 968°F and 945°F, respectively, whereas the average of Row 1 tubes supplied by the 1st inlet pipe is about 903°F. No TCs were installed at the top of Row 2 tubes supplied by the 1st inlet pipe, but assuming that the top of these tubes is 50°F lower temperature than their corresponding Row 1 tubes, (as is the case with the Row 1 and 2 tubes supplied by the 2nd pipe), then the average of top and bottom temperatures for the Row 2 tubes supplied by the 1st pipe is estimated to be 878°F, (about 90°F lower than the highest temperature tubes attached to the same headers).

The wide variation in RH2 tube outlet temperatures results in some tubes and header tubeholes operating at about 1110°F, at a time when the unit was producing steam at 1042°F, below its design HRH steam temperature.

Figure 23 presents a TSD plot at 03:05 on 5-8-04 during steady state operating conditions at a typical overnight load (85MW) with the attemperator producing a 164°F drop in steam temperature from its inlet to outlet. Note that as the attemperator injects more spray water the differences between bottom tube temperatures become even more pronounced. Also note that the upper temperature of many tubes on the left side of the reheater are at or above the header's design temperature of 1082°F. It should follow that portions of the header where these tubes attach are also operating above design temperature. This does not bode well for this header's creep life consumption.

4 Rapid Cooling of Headers - Borehole Cracking

As was previously noted (Figure 9), the greater the wall thickness of an HPSH or RH higher temperature header the more sluggish is its response to internal fluid temperature changes. Thicker headers must be heated significantly slower than thin headers during starts. Of even greater concern, rapid cooling by sub-cooled condensate of the tubeholes and header bore of thicker higher temperature headers causes severe tensile stresses that will lead to cracking at the intersection of the tube holes and header bore. This failure mechanism has been documented in numerous conventional plants around the world with headers of similar proportions to those in many HRSGs. There is no reason to believe HRSGs will not suffer the same consequences if temperature transients affecting the headers are not carefully managed.

5 Recommendations

- HRSG design issues
  - Use panels with a single tube row per upper and lower header pair in superheaters and reheaters to eliminate additional bending stresses at offset tube – to – header welds.
  - Limit the thickness and diameter of all HP SH and RH headers to minimize tube-to-header temperature differences and tolerate faster gas and SH/RH outlet steam temperature ramp rates.
  - Ensure that SH and RH drain systems quickly and reliably remove all condensate from tubes, lower headers, pipes and manifolds. The "worst case" for sizing drain pipes and valves is generally at atmospheric pressure.
  - Route RH drains and HPSH drains to separate blowdown vessels to prevent pressurizing of vessel above RH pressure during startup.
  - Ensure that under cold and hot operating conditions that all lower manifolds, interconnecting pipes, drain pipes, etc, have fall in the direction of normal flow.

- Provide large drains on cold reheat pipes before the HRSG to remove substantial condensate formed during cold starts and to dispose of any spraywater leakage at the HP bypass attemperator.
- Automate RH and HPSH drain control and block valves during starts and shutdowns
- Select RH and HPSH outlet design temps above baseload operating conditions to accommodate over temperature excursions during simultaneous ramping of CT and HP pressure
- Request changes to design code to permit limited periods of operation above, by a moderate amount, the nominal design temperature, since short periods of accelerated creep (with reduced pressure stresses) are much less damaging than the rapid life expenditure caused by overspraying in desuperheaters, (provided the high-high temp limit is well below material transformation temperature).

- CT design influences
  - Minimize the CT exhaust gas temperature at minimum spinning reserve load. This minimizes the SH and RH header tube-to-header temperature differences during startup and shutdown.

- Balance of Plant influences
  - Specify HP / Hot Reheat bypasses capable of high volumetric flow during startup. Bypasses sized for full CT load and full pressure cannot pass sufficient steam at low pressures to heat soak critical HRSG pressure parts at sufficiently low saturation temperatures during startup

  - Open the HP Bypass early (at CT startup on warm and hot starts) to provide cooling steam in the SH / RH to minimize tube-to-header temperature differences

- Operations Influences
  - Ensure SH and RH drains are correctly operated to remove all condensate within 1 or 2 minutes of CT ignition

  - Ensure HP bypass is opened as early as possible after CT start to cool SH and RH tubes and begin the heating of headers, pipes and manifolds

  - Maintain high HP drum pressure during CT/HRSG shutdown prior to an overnight or weekend shutdown such that HPSH and RH headers are as warm as possible at the next startup to minimize the peak tube to header temperature difference.

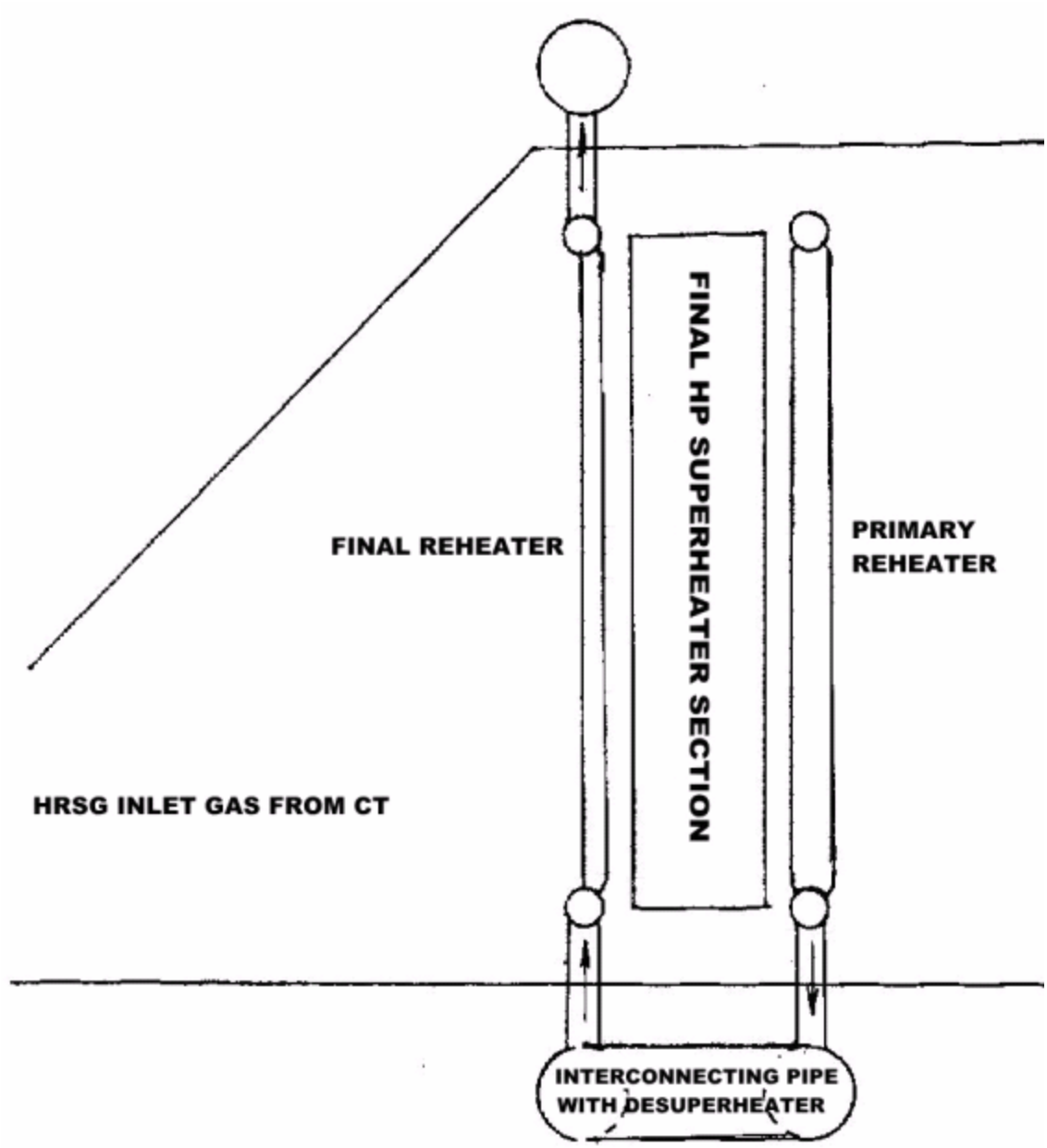
FINAL HP SUPERHEATER SECTION
FINAL REHEATER
PRIMARY
REHEATER
HRSG INLET GAS FROM CT
INTERCONNECTING PIPE
WITH DESUPERHEATER

Figure 1

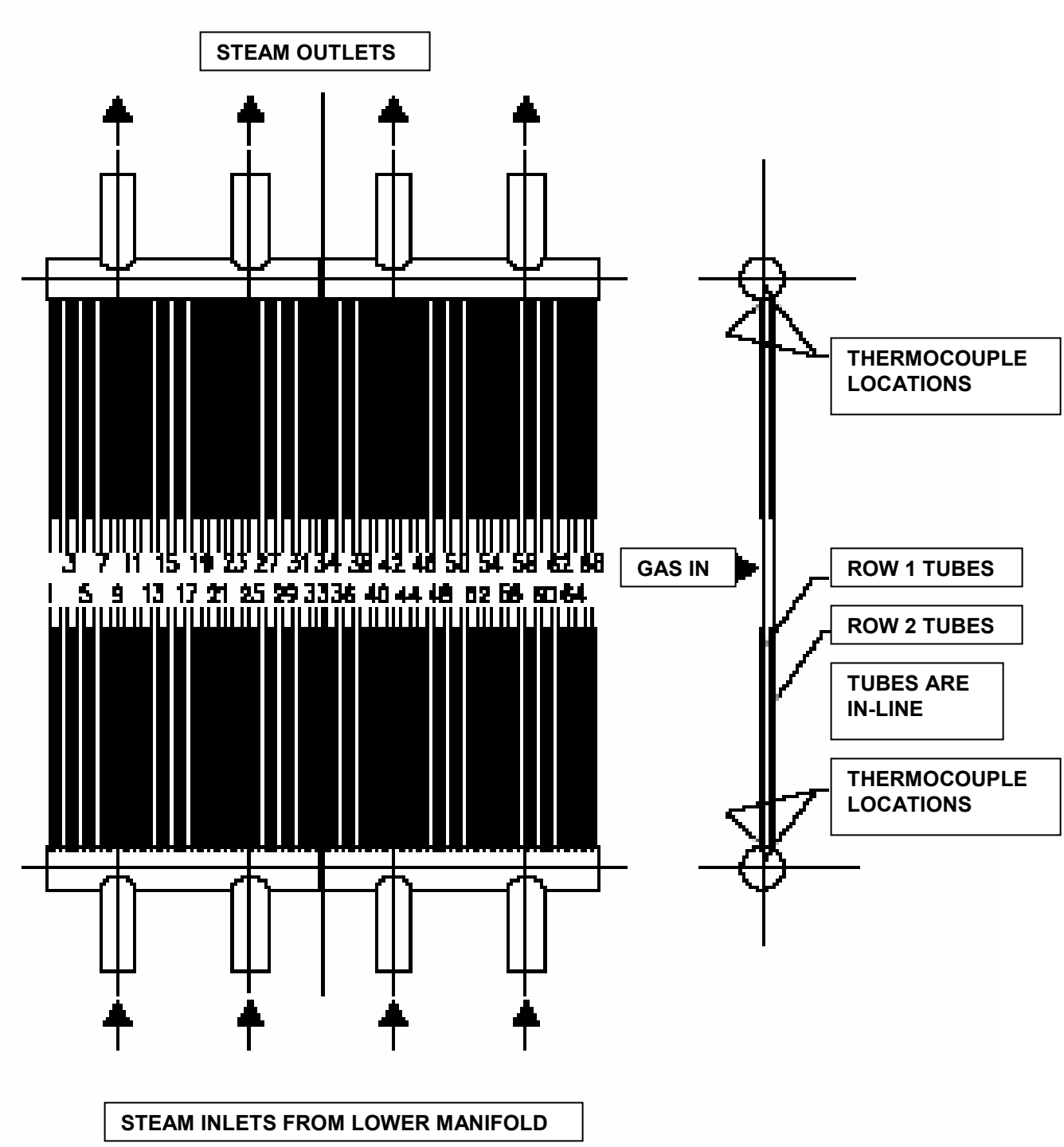
STEAM OUTLETS
THERMOCOUPLE LOCATIONS
GAS IN
ROW 1 TUBES
ROW 2 TUBES
TUBES ARE IN-LINE
THERMOCOUPLE LOCATIONS
STEAM INLETS FROM LOWER MANIFOLD

Figure 2

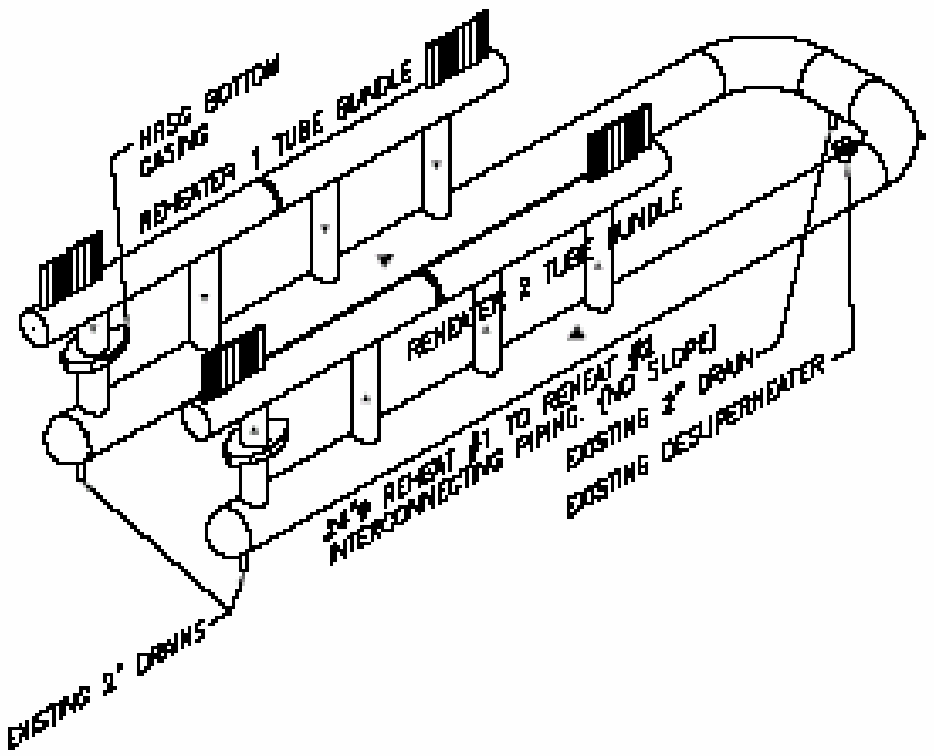

Figure 3

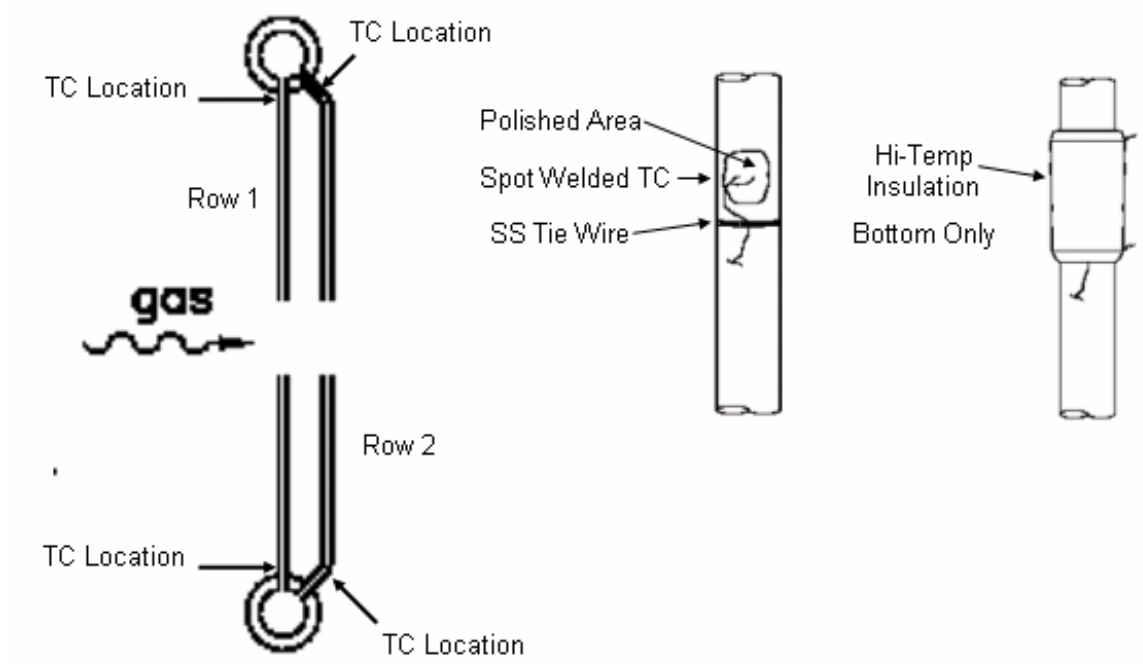

Figure 4

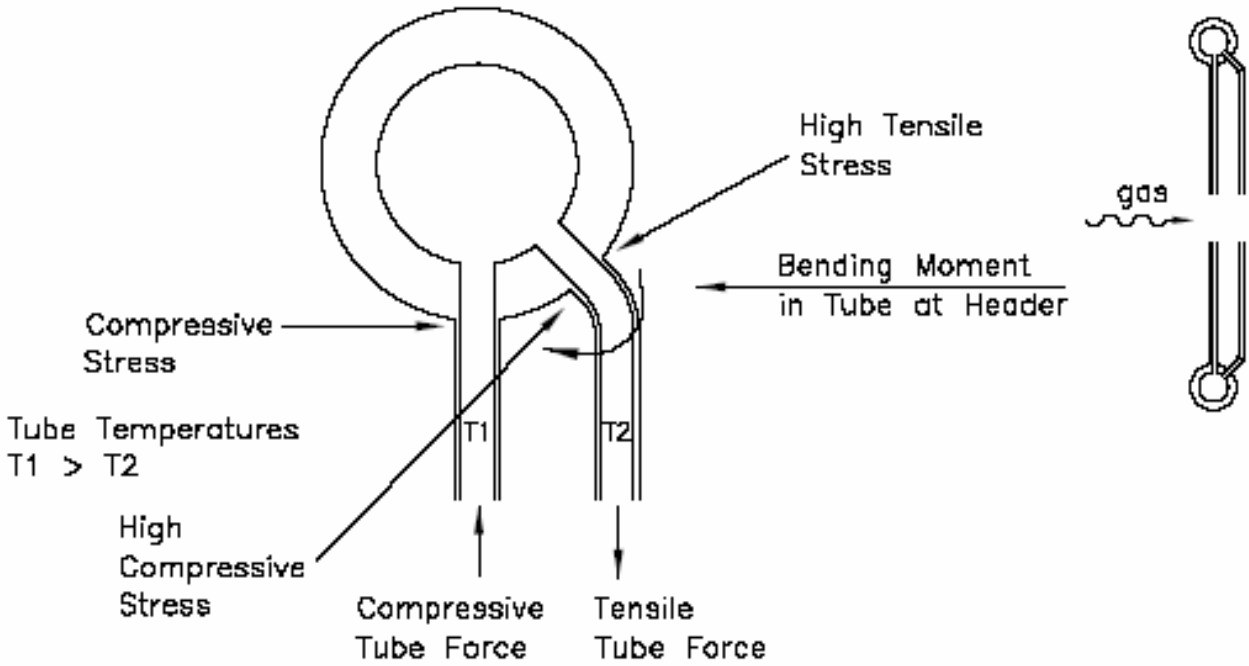

Figure 5

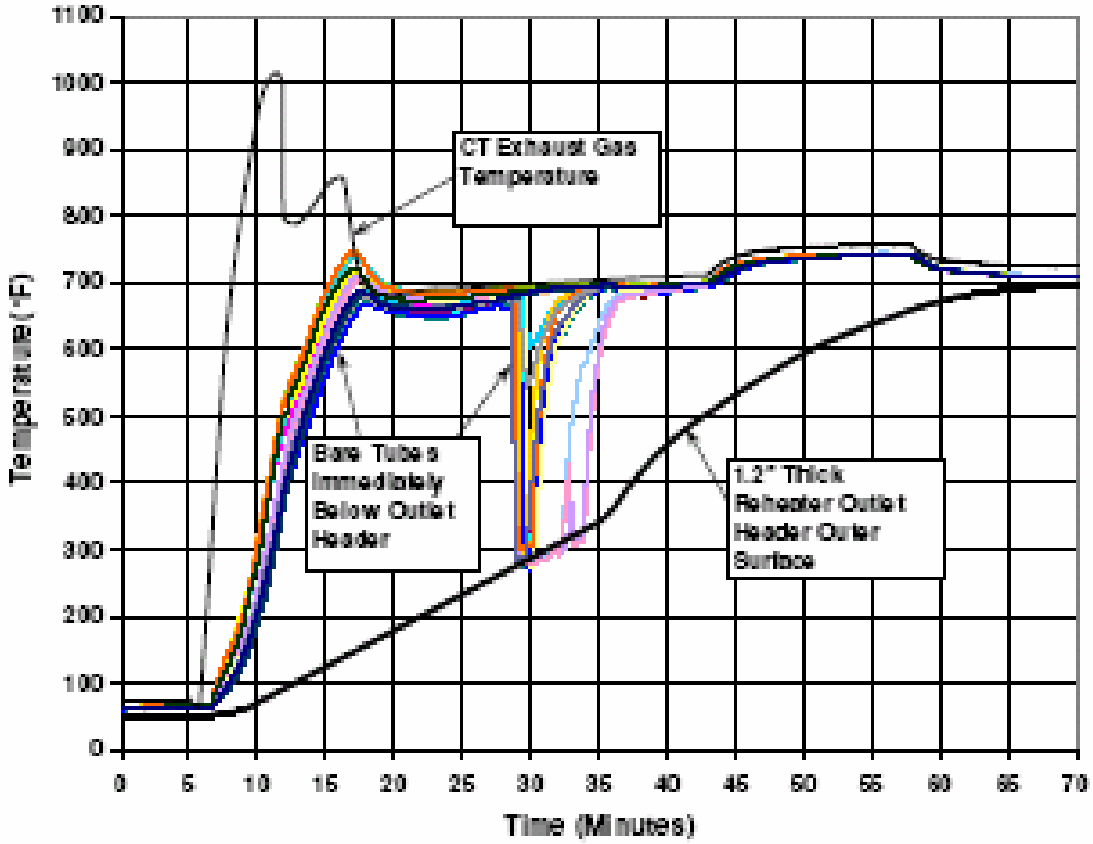

Figure 6

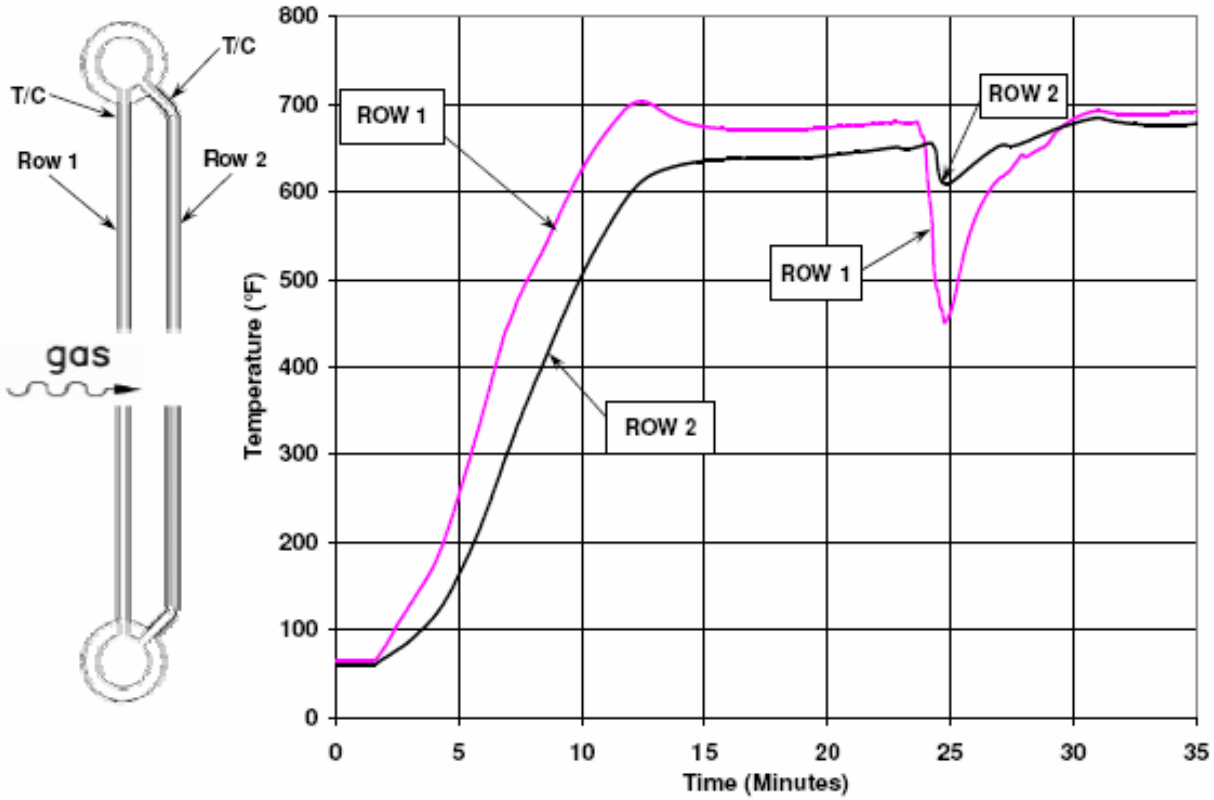

Figure 7

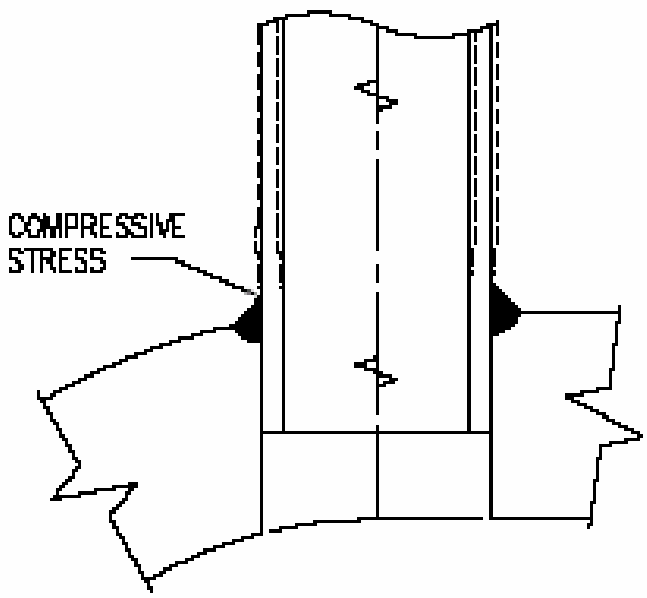

Figure 8

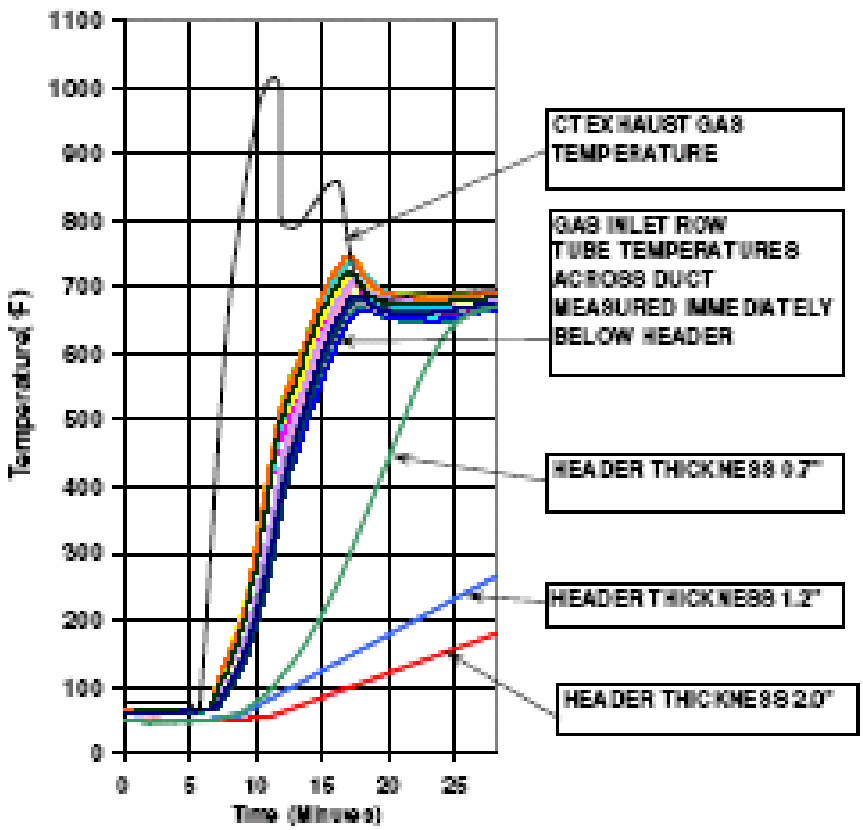

Figure 9

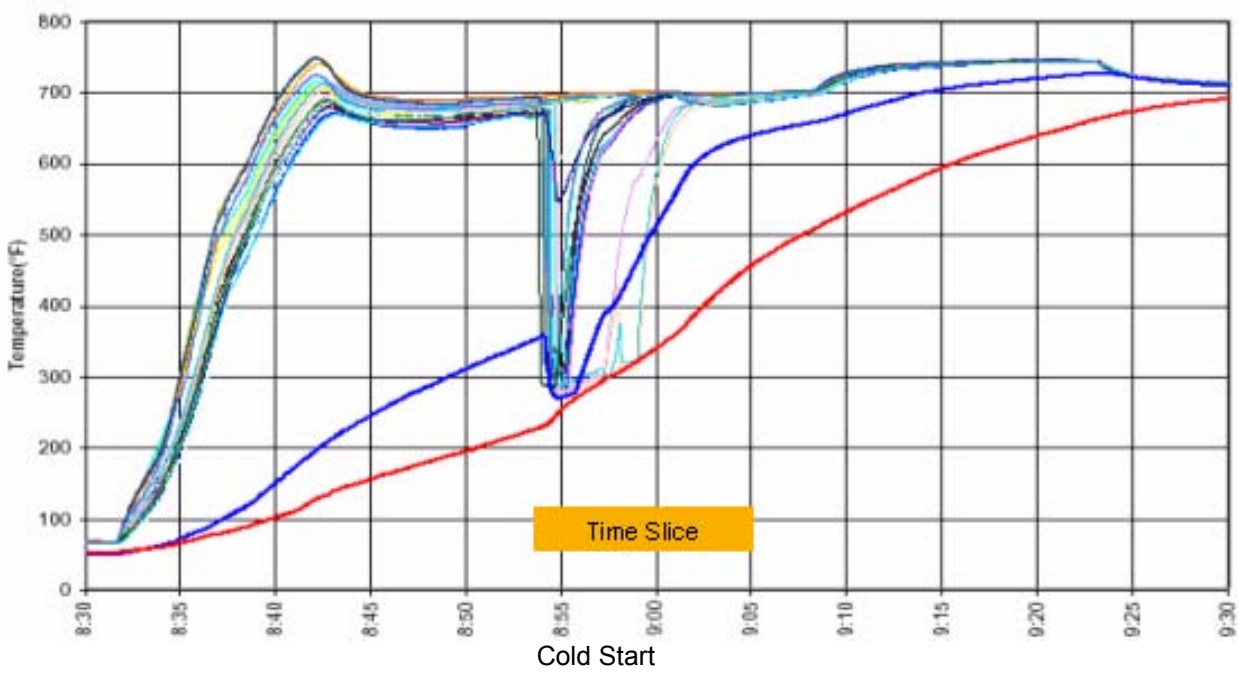

Figure 10

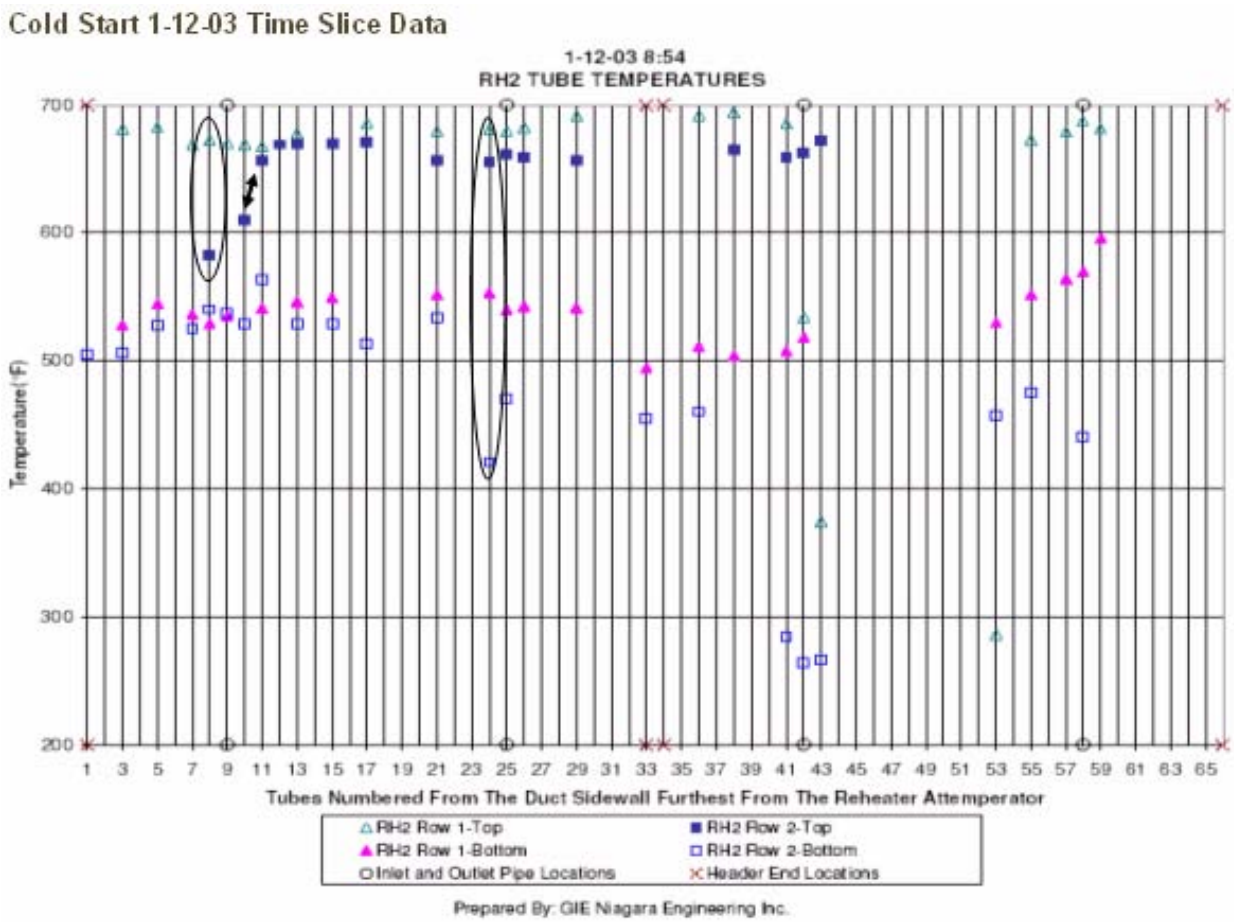
Cold Start 1-12-03 Time Slice Data
1-12-03 8:54
RH2 TUBE TEMPERATURES
Temperature (°F)
700
600
500
400
300
200
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57 59 61 63 65
Tubes Numbered From The Duct Sidewall Furthest From The Reheater Attemperator
RH2 Row 1-Top
RH2 Row 2-Top
RH2 Row 1-Bottom
RH2 Row 2-Bottom
Inlet and Outlet Pipe Locations
Header End Locations
Prepared By: GIE Niagara Engineering Inc.

Figure 11

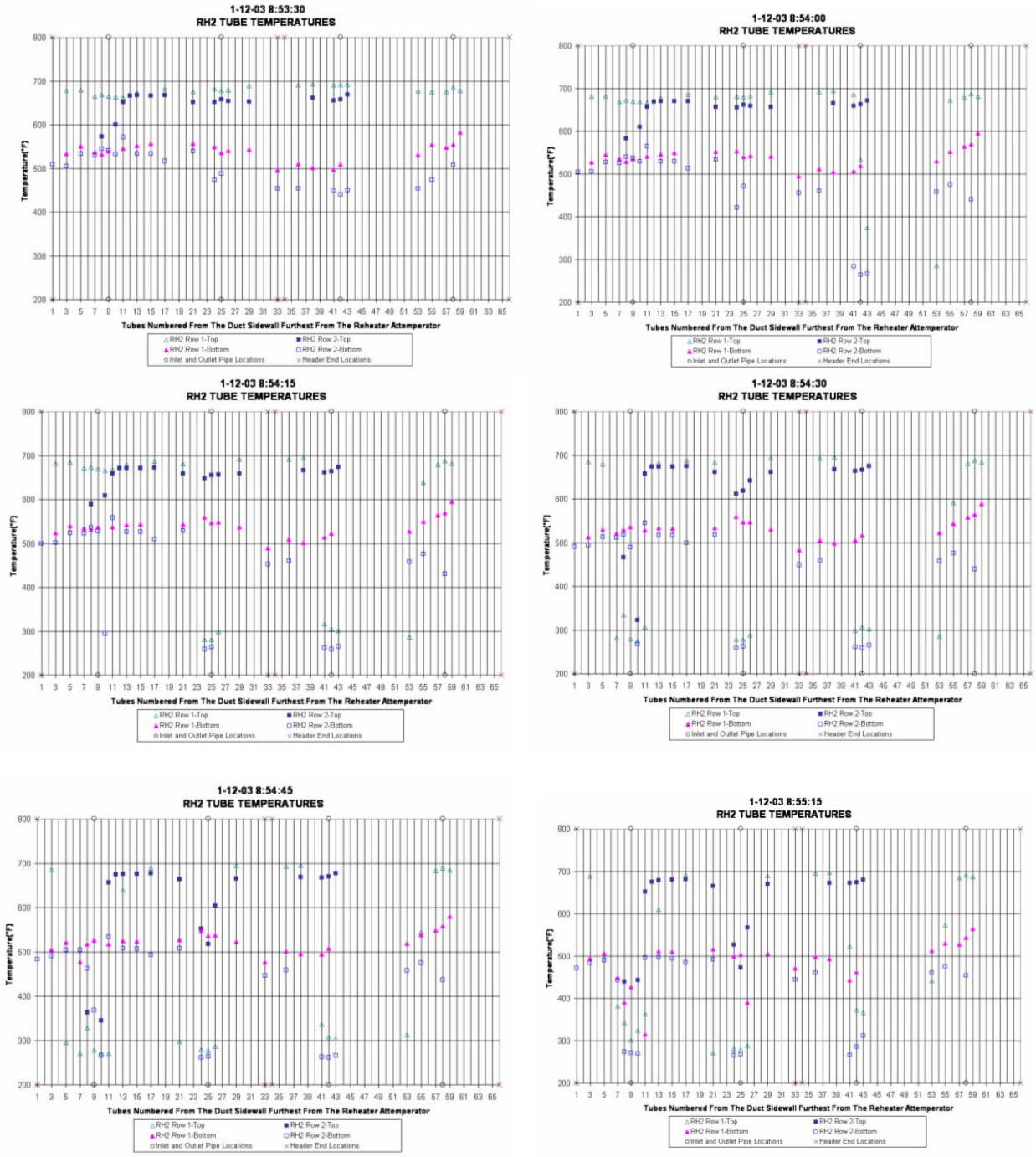
1-12-03 8:53:30
RH2 TUBE TEMPERATURES
1-12-03 8:54:00
RH2 TUBE TEMPERATURES
1-12-03 8:54:15
RH2 TUBE TEMPERATURES
1-12-03 8:54:30
RH2 TUBE TEMPERATURES
1-12-03 8:54:45
RH2 TUBE TEMPERATURES
1-12-03 8:55:15
RH2 TUBE TEMPERATURES
Temperature(°F)
Tubes Numbered From The Duct Sidewall Furthest From The Reheater Attemperator
RH2 Row 1-Top
RH2 Row 2-Top
RH2 Row 1-Bottom
RH2 Row 2-Bottom
Inlet and Outlet Pipe Locations
Header End Locations

Figure 12

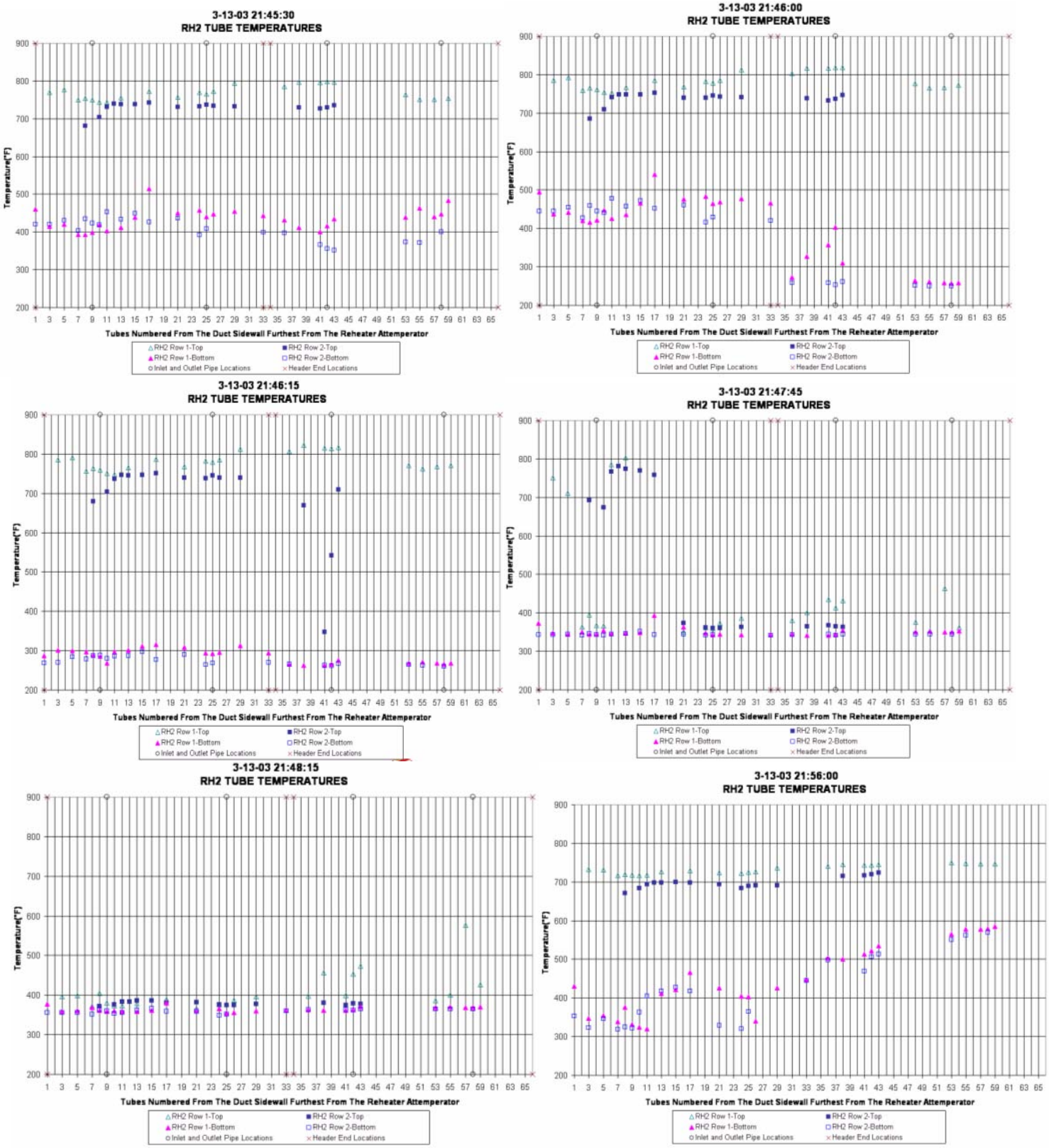
3-13-03 21:45:30
RH2 TUBE TEMPERATURES
3-13-03 21:46:00
RH2 TUBE TEMPERATURES
3-13-03 21:46:15
RH2 TUBE TEMPERATURES
3-13-03 21:47:45
RH2 TUBE TEMPERATURES
3-13-03 21:48:15
RH2 TUBE TEMPERATURES
3-13-03 21:56:00
RH2 TUBE TEMPERATURES
Temperature(°F)
Tubes Numbered From The Duct Sidewall Furthest From The Reheater Attemperator
RH2 Row 1-Top
RH2 Row 2-Top
RH2 Row 1-Bottom
RH2 Row 2-Bottom
Inlet and Outlet Pipe Locations
Header End Locations

Figure 13

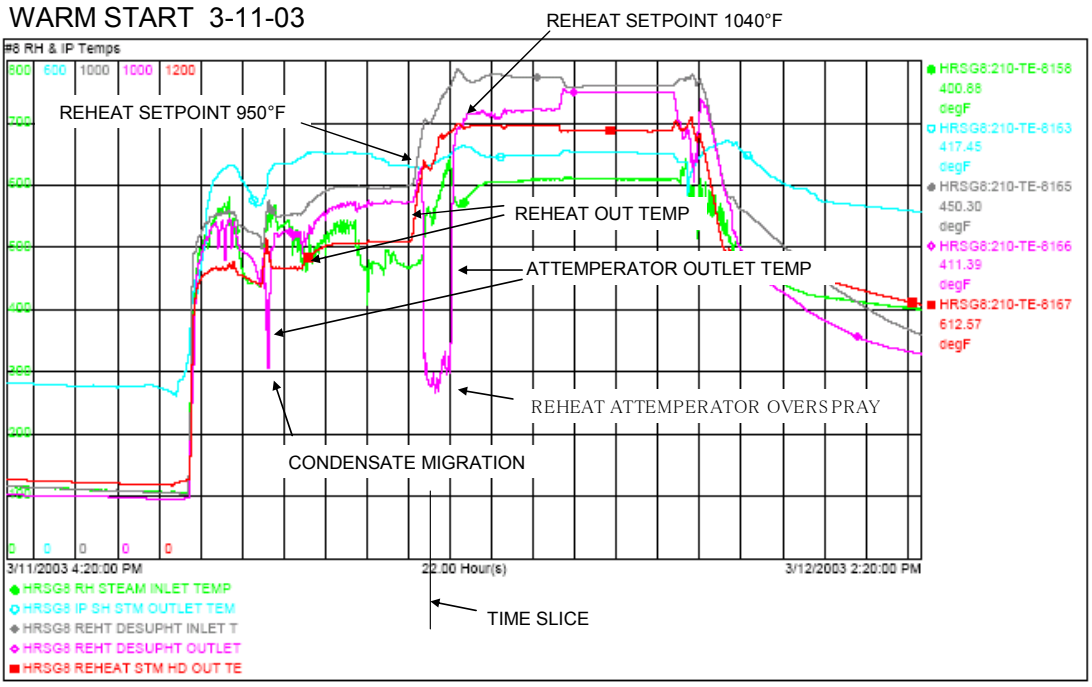

Figure 14

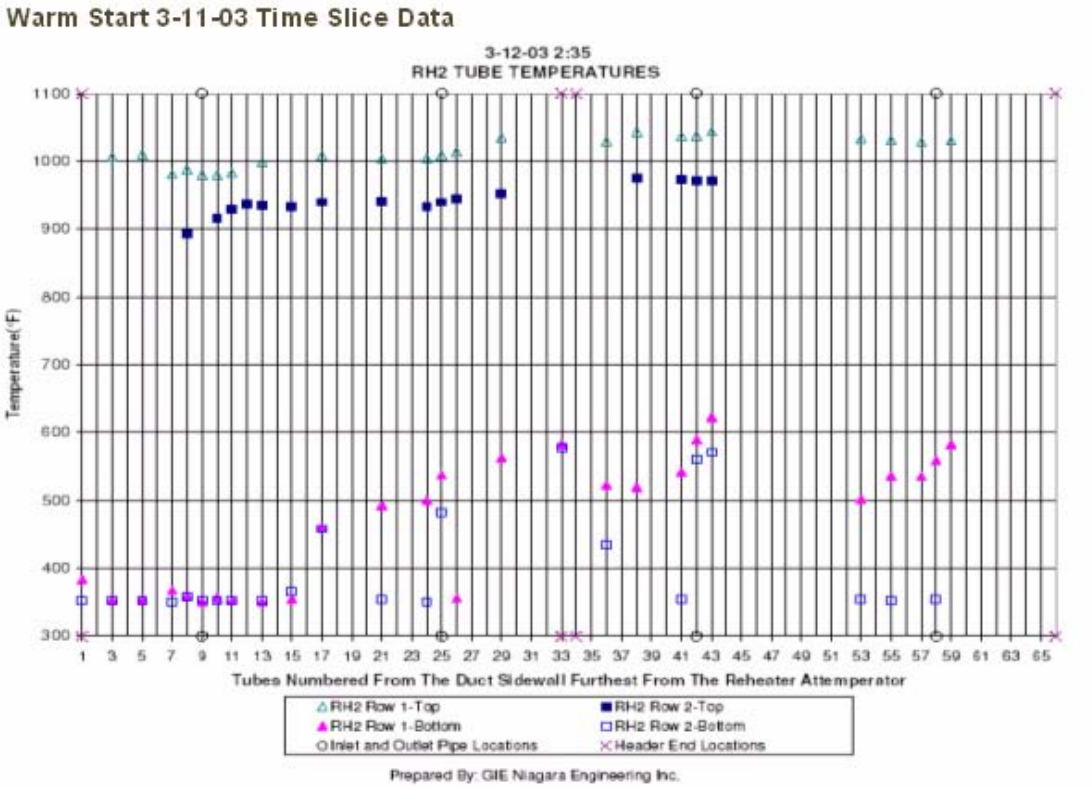

Figure 15

SHUTDOWN 3-14-03

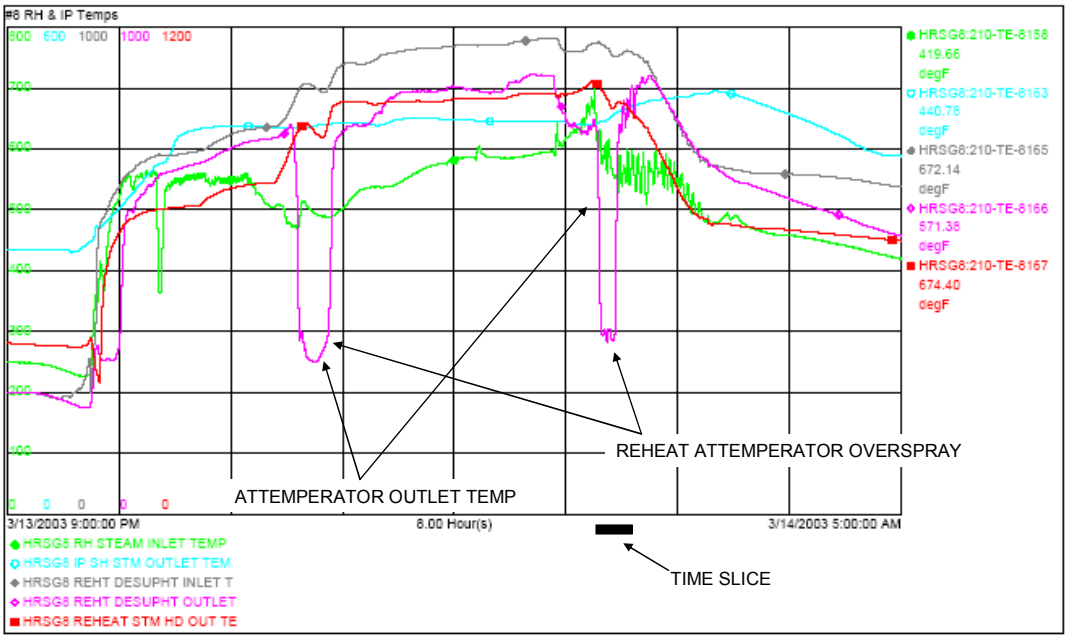

Figure 16

Shutdown 3-14-03 Top of Row 1 Tubes

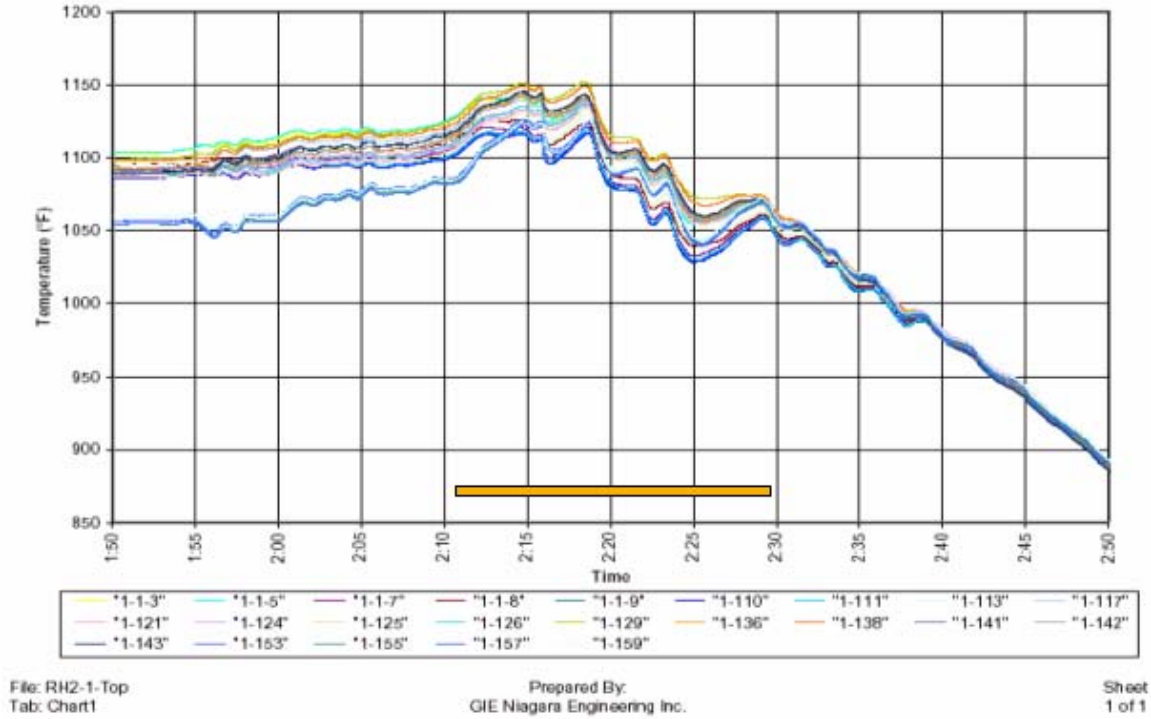

Figure 17

Shutdown 3-14-03 Top of Row 2 Tubes

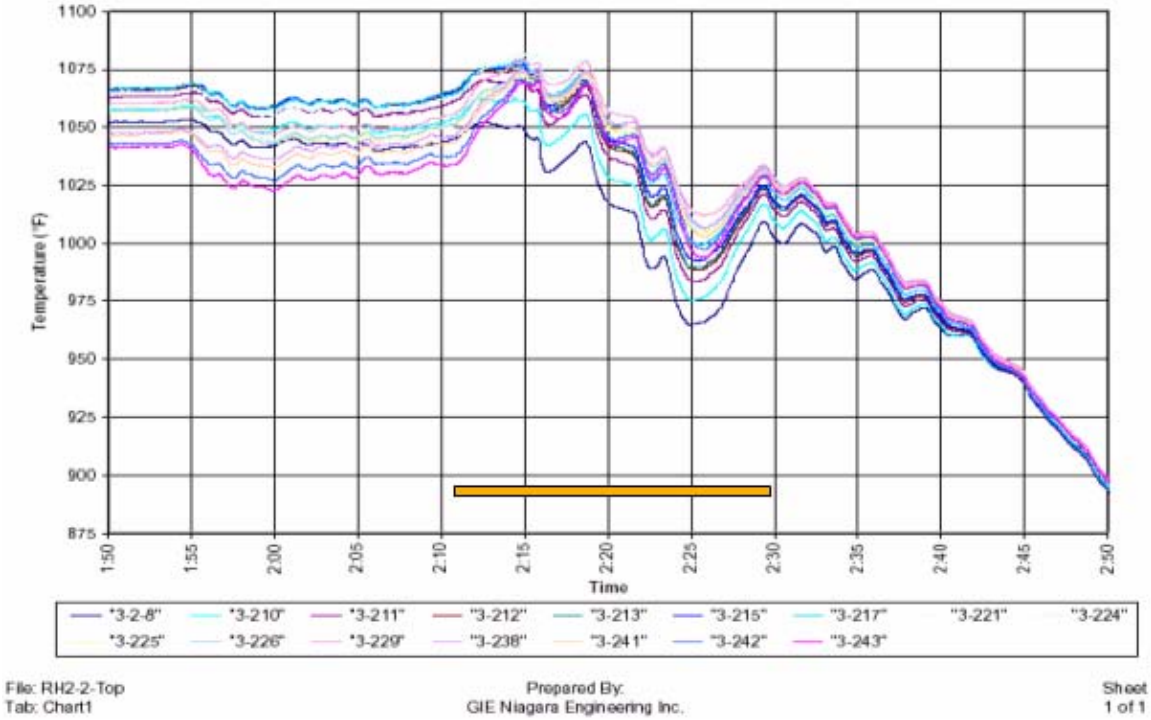

Figure 18

Shutdown 3-14-03 Bottom of Row 1 Tubes

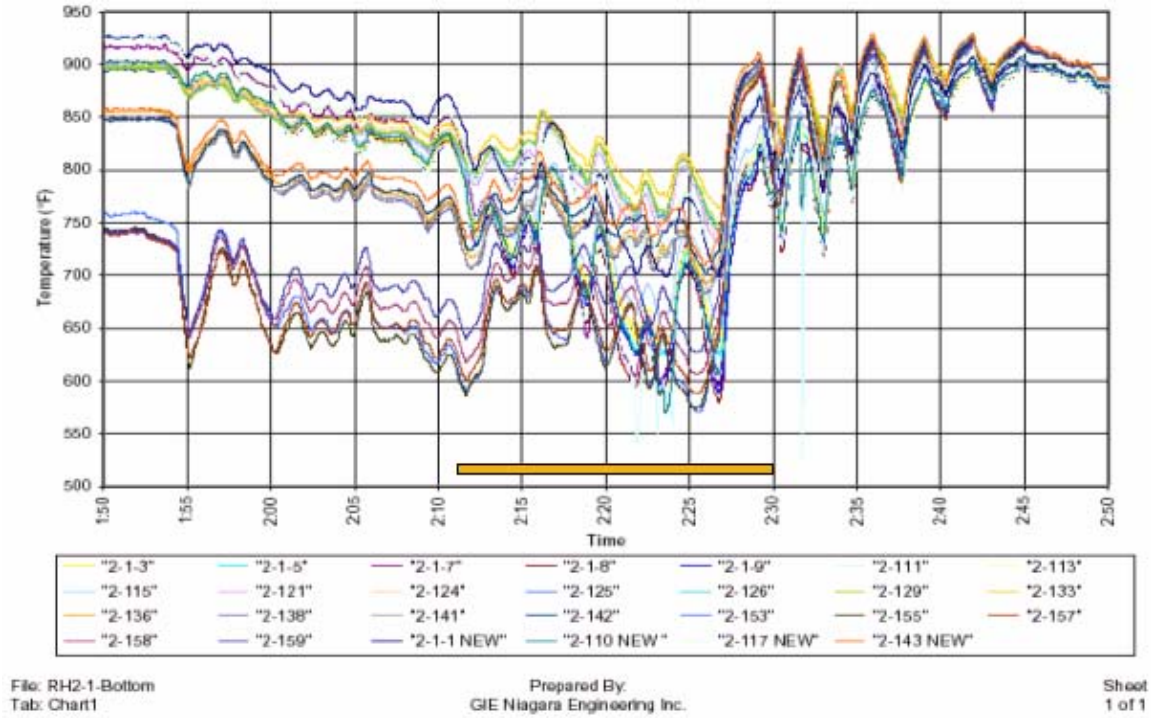

Figure 19

Shutdown 3-14-03 Bottom of Row 2 Tubes

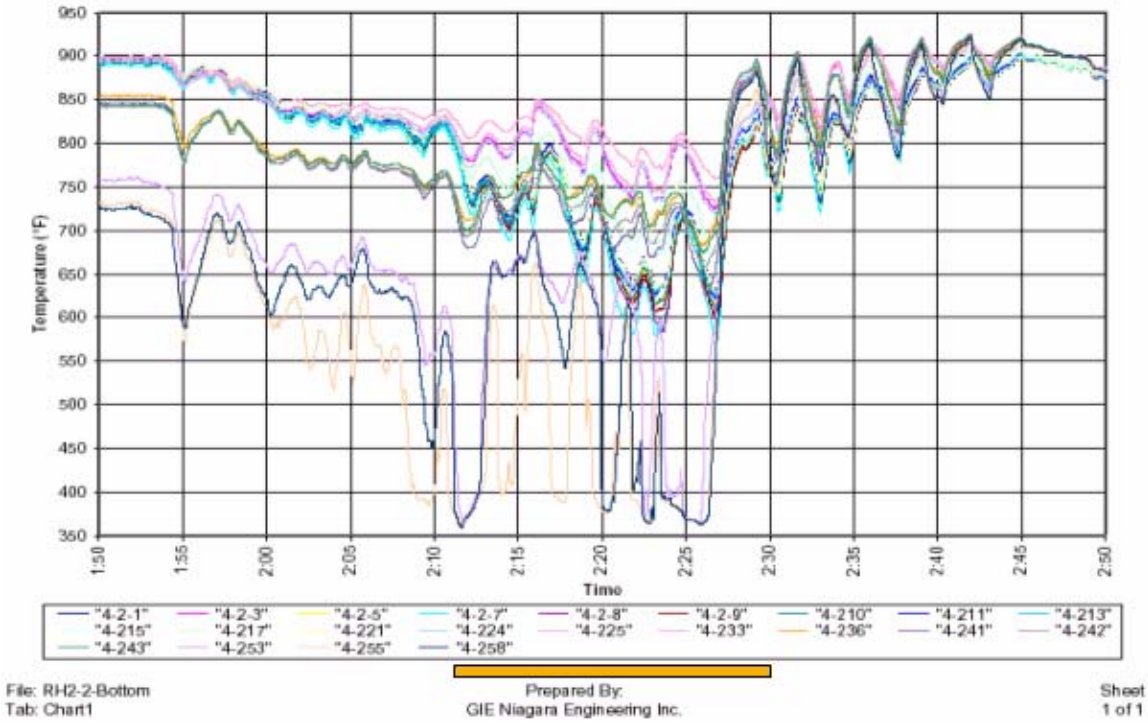

Figure 20

Steady State Data @ 179MW with No Attemperation – RH Steam Outlet Temp 1029°F

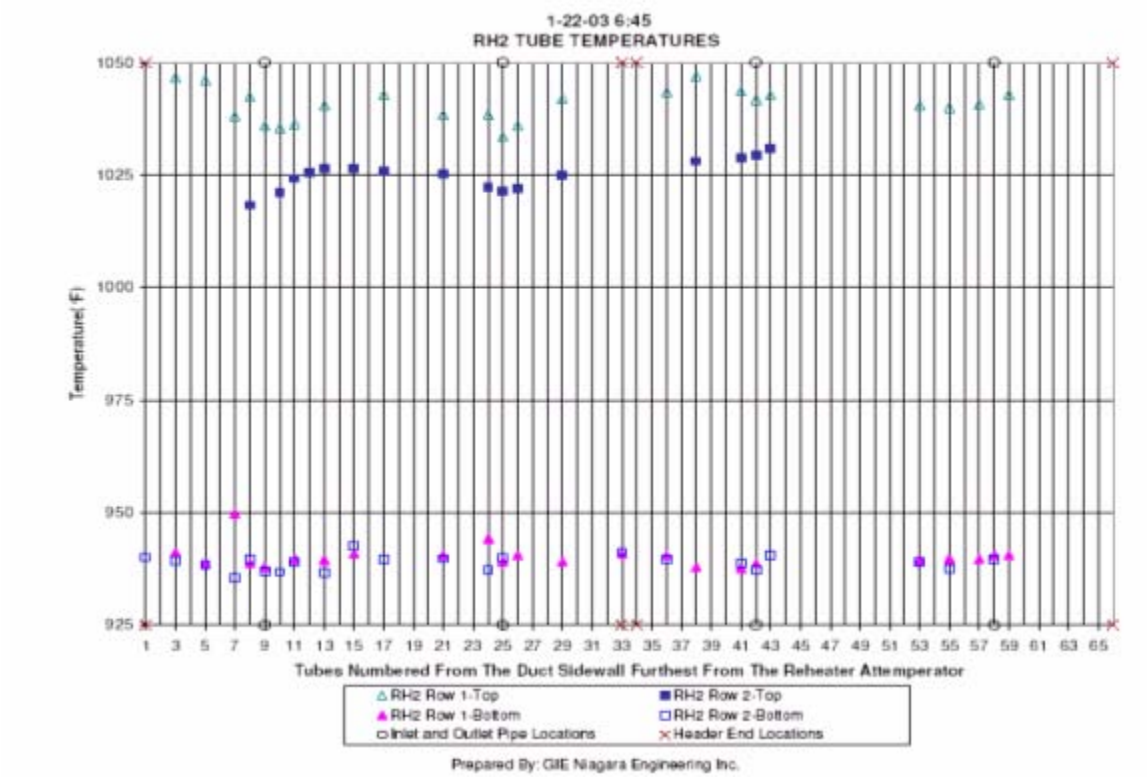

Figure 21

Steady State Data @ 110MW with 79°F Attemperation – RH Outlet Steam Temp 1046°F

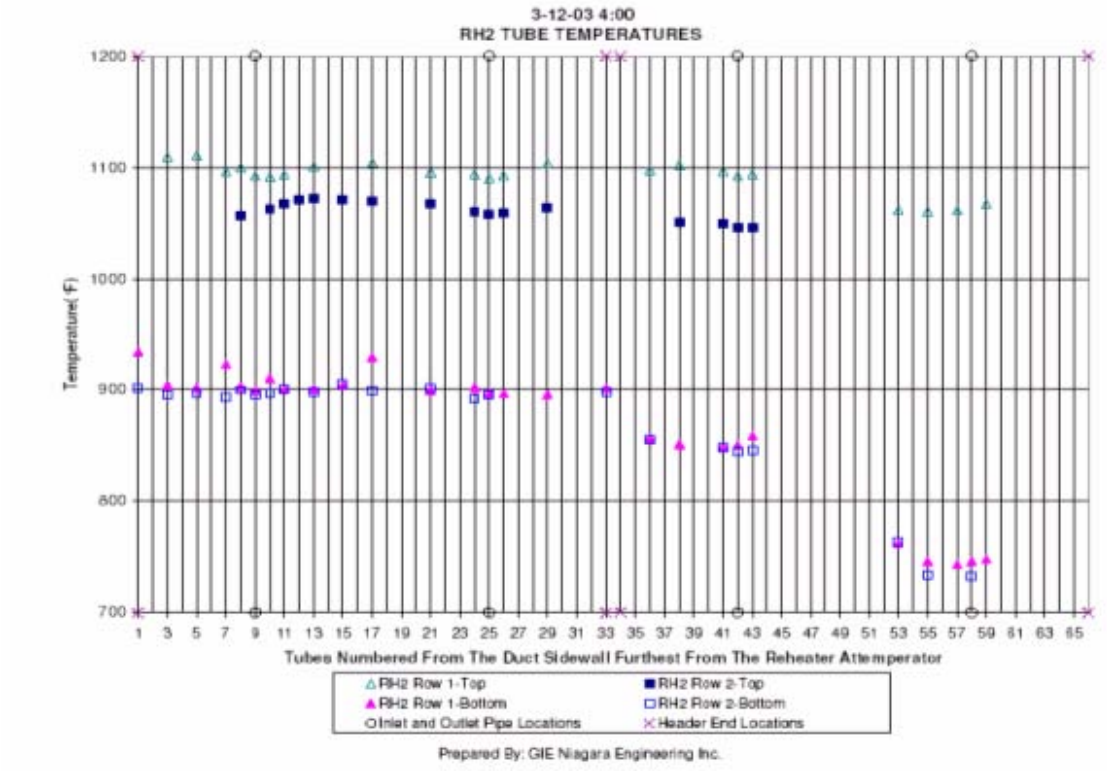

Figure 22

Steady State Data @ 85MW with 164°F Attemperation – RH Outlet Steam Temp 1028°F

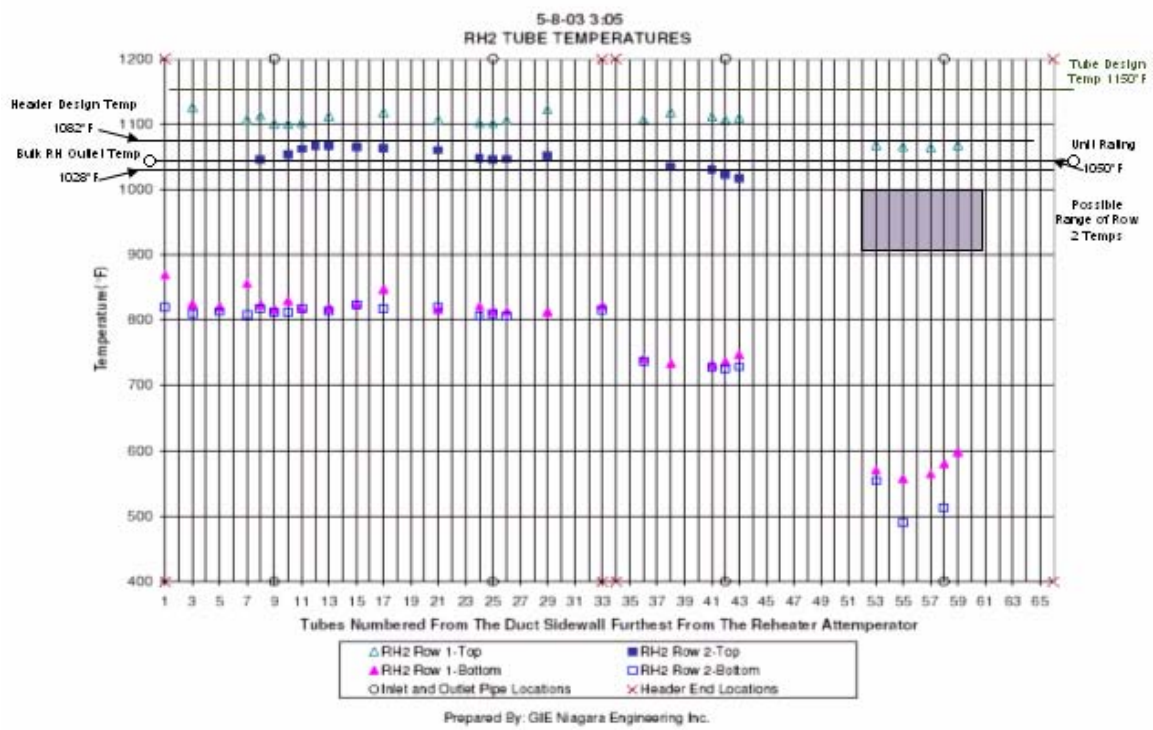

Figure 23

References

1. Pearson, J.M., Anderson, R.W., “Reliability and durability of large heat recovery steam Generators”, *Proceedings of Institution of Mechanical Engineers, (U.K.),* Volume 213, Part A, pp151-168.

2. Pearson, J.M., Anderson, R.W., “Root causes of transient tube temperature anomalies measured in horizontal gas path HRSGs”, *EPRI International Conference on Boiler and HRSG Tube Failures and Inspections”* Phoenix, Arizona, November, 2001.

3. Pearson, J.M., Anderson, R.W., “Influences of HRSG design and operation on the durability of two-shifted HRSGs”, *European Technology Development Conference on HRSG Technology,* London, November, 2003.

4. Dooley, R.B., Paterson, S.R., Pearson, J.M., “HRSG Dependability”, *European Technology Development Conference on HRSG Technology,* London, November, 2003.

5. Dooley, R.B., K.J. Shields, S.R. Paterson, T.A. Kuntz, W.P. McNaughton, and M. Pearson, *Heat Recovery Steam Generator Tube Failure Manual*, TR-1004503, EPRI, Palo Alto, CA., 2002.

6. Dooley, R.B., K.J. Shields, S.R. Paterson, T.A. Kuntz, W.P. McNaughton, M. Pearson, and R. Sirois, *Delivering High Reliability Heat Recovery Steam Generators*, TR-1004240, EPRI, Palo Alto, CA. 2003.

Flow Assisted Corrosion
Failures/Water Chemistry Aspects

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Abstract

Flow assisted corrosion (FAC) is a leading cause of tube damage and failures in HRSG systems. This paper provides a discussion of the FAC mechanism and related water chemistry parameters involved in the corrosion process. Solutions and operational practices to mitigate FAC are presented as well as qualitative results from an FAC modeling effort.

Introduction

Flow assisted corrosion (FAC) has been characterized by EPRI as a leading cause of tube damage and failures in HRSG systems. This mechanism first gained notoriety however when failures were experienced in high pressure feedwater piping elbows in nuclear plants in the 1980's. Failure investigations and results from several studies at the time generated a better, although not a complete understanding of the mechanism. The dissemination of this knowledge was also somewhat limited in one segment of the power plant community. Since then and with the increase proliferation of combined and co-generation power plants, FAC related damage has also increased as certain components in these systems can be exposed to similar conditions. Field investigations of this type of damage have progressively augmented our knowledge and further understanding of the root cause mechanism and solutions. This paper provides a discussion of these experiences and related water chemistry parameters involved in the corrosion process. These results and relationships have been utilized over the ensuing years to formulate predictive methods and solutions in order to mitigate FAC in HRSG and other power plant components. It should be realized however that even though many of the conditions responsible for FAC have been identified, quantitative predictions still remain elusive.

Fundamentals

Flow assisted corrosion (FAC) of carbon steel is defined as the acceleration or increase in the rate of corrosion caused by the relative movement between a corrosive fluid (either single phase water or two phase water and steam mixtures) and a metal surface. The dissolution of the protective magnetite film is enhanced by the mass transport of soluble iron species (Fe II) away from the surface. The rate of mass transfer of these species to the bulk of the fluid is accelerated by flow/turbulence. This will increase metal loss as iron oxidizes to replace the dissolved film and so on.

FAC is a chemical/corrosion process mitigated by specific water chemistry conditions within a particular fluid temperature range. Fluid temperature and fluid flow mechanics influence the location in boiler or HRSG components where FAC could preferentially occur. A brief review of these parameters follow.[1, 2]

***pH and oxidation-reduction potential (ORP)*:** The pH and the oxidation-reduction potential (ORP) of the fluid affect the solubility of iron oxide/hydroxide as typically represented by the Sweeton and Baes equilibrium reaction:

$$1/3Fe_3O_4 + (2\text{-}b)H^+ + 1/3H_2 = Fe(OH)_b^{\ (2\text{-}b)+} + (4/3\text{-}b)H_2O.$$

Ferrous hydroxide on the right side of the equation is the soluble product. As indicated by this equation, the dissolution of magnetite is influenced by the oxidation-reduction potential (ORP) of the solution as represented by hydrogen molecule (H2). It is also influenced by the pH as represented by the hydrogen ion (H+). Thus lowering the pH and /or the ORP (toward negative potential or reducing conditions) will increase the dissolution rate of the protective oxide layer and accelerate corrosion.

Oxygen or oxidizing conditions would normally be thought to cause additional corrosion and in the presence of dissolved solids, corrosion is increased. In an environment of high purity water (cation conductivity less than 0.2 microSiemens), oxygen acts to stabilize the protective coating and actually reduces the rate of metal loss. This is the same principle being exploited for feedwater Oxygenated Treatment (OT).

Temperature: The effect of temperature on metal loss parallels the effect of temperature on solubility of iron oxide (magnetite) in water. At low temperatures, the oxide that is formed is iron hydroxide; this shifts to magnetite at high temperatures. These two materials have different solubility characteristics, accounting for a temperature peak around 150°C-177°C (300°F – 350°F). Minimum and maximum temperature limits have been reported for the most part in the range of 77°C (170°F) - 232°C (450°F), respectively. This parabolic solubility relationship with temperature is the reason that the low temperature feedwater system and the intermediate/high pressure components do not normally experience FAC.

***Velocity/Turbulence*:** Figures 1 and 2 are economizer inlet tubes/bends, which have experienced FAC. The fluid velocity in economizer tubes is typically in the range from 1-3 ft/sec. This is certainly not considered high. However, whenever FAC has occurred in a system, the first general reaction has been that the velocity must be too high. Yet as just indicated, experiences indicate otherwise. The more important factor in all of these cases is turbulence. Even at these low velocity, there are tube configurations (i.e. bends, restrictions, etc.) and pipe fittings intrinsic to any boiler systems where turbulence or eddies are generated. Turbulent flow is characterized by a churning motion that can generate multiple time increases in the transport properties of the fluid, or in this case, the diffusion (eddy diffusivity) of the chemical species involved in the surface reaction. The effect of turbulence increases the mass transfer rate of reactants and products to and away

from the metal oxide/water interface. Under adverse fluid chemistry conditions (discussed below), the metal/oxide equilibrium is disturbed and the dissolution of the oxide or corrosion rate is increased. If there weren't significant turbulence or eddy diffusivity, the process reaction would then depend on molecular diffusivity (concentration differences between the bulk fluid and the metal/fluid interface) which is much slower and would not appreciably affect the equilibrium.

In the past few years with advances in computational fluid modeling, we can (at least qualitatively) model tube locations/geometry as to how they affect fluid flow. For example, let's compare a tube bend, which has been susceptible to FAC and a straight section of tubing which has not been susceptible. This is illustrated in figure 3a that represents a 17°tube bend with a fluid velocity of one meter/sec (approximately 3 ft/sec). As seen, the turbulence increase in the bend is approximately twice than that in the straight section (vertical tube section before the bend). Figure 3b shows an even higher turbulence increase in a 45°tube bend. The degree of turbulence is represented or modeled by the kinetic energy generated by the turbulent fluctuations (or local velocity gradients). In other words, the generation of turbulence imparts an energy loss to the main flow. This energy loss must equal the mean kinetic energy of the turbulent fluctuations. The change in flow direction at the bend generates additional turbulence to that generated just by the surface friction as in the straight portion of the tube. The corrosion rate is influenced by the degree of turbulence. However, it is evident that the relative magnitude of the turbulence doesn't need to be very high (or many times higher than that in the straight section for the same velocity) to generate higher mass transfer rates and cause FAC as occurred on these types of tube bends. The contours of the turbulent field in the bend and just past it also simulate the corrosion pattern

Water/steam separators in the LP drum have also been susceptible to FAC (see figure 4) since turbulence is generated in this area (fluid velocity on average are around 1-2ft/sec). It's significant to point out from our experiences that in systems where fluid conditions are such that the potential for FAC is significant, these internals seem to be first to experience FAC. Since it is not difficult to inspect the drum, the internals are a fairly good indicator if FAC conditions prevail. The occurrence of FAC in this type of drum internals is first noticed by the oval nature of the holes.

FAC also imparts a distinct surface pattern often called a scalloped surface as indicated in figure 5. This physical feature helps to distinguish FAC from other wastage corrosion mechanisms.

The other important point of this section is that FAC or metal "wastage" at these low velocities and turbulence is not a mechanical abrasion or erosion related mechanism.

Cycle Chemistry Considerations

In the steam/water system, FAC is mainly observed in the temperature range between 77°C (170°F) - 232°C (450°F), with a maximum in the temperature range around 150°C-177°C (300°F – 350°F). Regions of concern are:

- Economizer tubes at HP and IP inlet headers
- LP-evaporator surfaces at bends
- LP-drum internals
- LP horizontal evaporative tube bends

To date, economizer, low pressure evaporative tubes (at bends), and drum internals have experienced FAC in several heat recovery steam generators in combined and co-generation cycle plants. Economizer inlet tubes have experienced FAC due to low pH conditions (in 3 of these plants, steam purity requirements did not allow the use of feedwater pH control chemicals, thus the pH was in the range of 6.5 to 7). Evaporative tubes and other LP components such as drum internals with few exceptions have normally not experienced this type of attack with either All Volatile Treatment or AVT (pH in the range of 9.0 –9.6) and certainly not with strong alkaline chemical additives (such as phosphates).

Several plants experienced FAC of drum internals in LP boilers and at economizer inlet tubes/bends. In these plants, an organic water chemistry program (organic dispersents, organic amines, and organic oxygen scavengers) was used.

In summary, a fluid environment needs to be provided that can promote oxide stability and at the same time meet plant requirements. The materials of construction in the feedwater system are protected from corrosion by controlling the pH and oxygen concentration with AVT. As the name implies, the treatment chemicals must be volatile, which means that when water is completely evaporated, no solid chemical residue must be present (i.e. zero solids treatment). This characteristic allows the use of feedwater for desuperheating (water is sprayed into the superheater to control steam temperature). When the boiler water is also on "AVT", it means that no changes or chemical (i.e. ammonia) additions are made to it. Since some portion of this chemical will volatilize in the higher fluid temperature environment, the boiler water pH will be slightly lower than that of the feedwater. In combined cycle plants with three pressure levels, quite often the cycle design requires that the LP boiler drum also serve as the feedwater tank and/or integral deaerator. In this case, the LP boiler water becomes the feedwater to the other boilers as well as the desuperheater spray water source. Thus the boiler water as explained above must contain only volatile chemicals and has similar qualities as the feedwater.

Understanding the Limitations of AVT

pH Control Additive - The recommended AVT in combined cycle plants consists primarily of ammonia injection into the feedwater to control pH in the range 9 – 9.6. An inherent characteristic of ammonia or other amines is the inability to buffer or effectively neutralize acidic agents at higher temperatures. This is the result of its decreasing ionic dissociation at higher temperatures. Consequently, if one were able to measure the local pH at high temperature, the pH would decrease as the fluid temperature increases, as illustrated in figure 6. For example, strong alkaline buffers such as sodium phosphate and sodium hydroxide do not exhibit this relationship with temperature. The pH remains relatively constant over the temperature range. Therefore, with AVT, relatively small amounts of salts or other acid producing substances (organic contaminants or organic additives) can have a significant effect on pH in higher temperature regions. It should be noted that this relationship is taken into account when formulating the cycle water chemistry regime. However, operators must also realize that the AVT treatment scheme is less "conservative" and requires immediate attention should the feedwater/boiler water become contaminated by either acid or caustic producing salts or substances.

In this regard, figure 7 illustrates the effect on pH with temperature by salts such as magnesium chloride. This is the infamous salt in seawater that hydrolyzes to hydrochloric acid in a high pressure/high temperature boiler water during a condenser leak incident. However, as shown in figure 7, some effect on pH begins to occur in the temperature range between 200°C and 250°C (392°F and 482°F). Figure 8 shows a similar effect on high temperature pH by organic acids.

Unlike ammonia, strong alkaline substances such as trisodium phosphate used in the boiler water provide a high pH, unaffected by temperature, and can form stable/non-volatile compounds. In these cases, the potential for FAC is negligible even in the critical temperature range (low pressure evaporative section) discussed above.

Oxygen Scavengers - Chemicals such as hydrazine and other oxygen scavengers are restricted or not used if the feedwater oxygen concentration is generally maintained below 10 ppb by mechanical deaeration. Hydrazine or hydrazine substitutes are reducing agents which will lower the ORP and increase the FAC potential in carbon steel components where the fluid temperatures are in the range of approximately 77°C (170°F) to 232°C (450°F). Figure 9[3] illustrates the influence of hydrazine on the ORP and the iron level in feedwater. As hydrazine is reduced, the ORP increases toward the positive or oxidizing potential and the level of iron decreases thus indicating that the FAC rate is also being reduced. Other studies [4] show (figure 10) the effect of oxygen or oxidizing potential in lowering the rate of FAC. It was found that as little as 8 ppb oxygen would arrest FAC. It also indicated that even if hydrazine is present but the water contains residual oxygen, then oxygen is still controlling the reaction rate. However, if oxygen is zero and hydrazine is present, then the ORP is driven to very negative potentials that can substantially increase the corrosion rate, as already indicated in figure 9.

In a combined cycle plant where there are no process steam requirements (i.e. cogeneration plant), ammonia is the preferred/recommended feedwater pH control additive over other amines. All other amines (morpholine, cyclohexylamine, etc.) as well as hydrazine substitutes are organic chemicals. At higher fluid temperatures (boiler, superheater, reheater), these substances will in general thermally degrade into carbon dioxide and organic by-products which may include organic acids. These by-products are then recycled with the condensate and feedwater. In summary, high feedwater pH controlled with ammonia and no oxygen scavengers are recommended as long as the normal oxygen content is less than 10 ppb. The need to use organic amines/organic oxygen scavengers for feedwater and condensate chemistry control in co-generation facilities should be carefully evaluated for each specific site.

Modeling FAC Potential

As discussed in the introduction, attempts have been made to develop a model utilizing field experiences and observations, results from root cause analyses, and literature references. It is recognized that the ability of FAC models to quantitatively predict absolute wastage rates is limited. As learned from field experiences, some of this limitation stems from the inability to adequately define the specific flow regimes, geometric, and chemical factors in the regions where attack has been observed. For this reason, the predictive potential of this model (and others) is intended to be like a "go-no go" gage and thus the results are presented as an index. This is a "work in progress" and updates/revisions are considered/made as new information or experiences are collected.

The model initially considered AVT cycle chemistry using ammonia and a feedwater pH range of 7.0 to 9.4. ORP field data was generally lacking (still is) so the most negative potential considered (in the formulations) was that represented by a zero oxygen concentration. Design parameters such as temperature, flow rates, geometry or tube dimensions and steam qualities are those typical of HRSG's in combined cycles.

Model Derivation

The model is derived from an empirical relationship that predicts FAC rates based on defined input for pH, oxygen concentration, fluid velocity, material composition, temperature, exposure time, and a Keller geometric factor. [5] The geometric factor is selected based on the location within the unit. These factors are related to velocity/turbulence and a dimensionless value is assigned to varying geometries such as a straight tube section, 90° bends, tees, etc. Larger values (or factors) denote a greater propensity for flow disturbances.

In the case of single phase flow, the average bulk velocity and bulk water chemistry was used. In locations of two-phase flow (LP evaporator tubes), it was assumed that the flow was annular flow. This flow type is characterized by a metal wall that is wetted by a constantly flowing contiguous film of slower moving water and the two-phase mixture flows more rapidly through the center of the tube. For this case, a water film velocity was calculated and used as the input velocity for the model. Since the distribution of

ammonia in water and steam is temperature dependent, the ammonia distribution factor was calculated. The factor was used to determine the concentration of ammonia remaining in the liquid film of water. The pH of the liquid was based on this calculated value. Within the two-phase region, the most conservative approach was taken by assuming that the oxygen concentration resides entirely within the steam. The calculated values for the two-phase regions are based on 0-ppb oxygen in the film of liquid water on the tube wall.

As stated earlier, the intent of the model is to provide an index or an assessment of the potential for FAC since the absolute corrosion rates have a high degree of uncertainty. The process for normalizing the data (to derive an index) utilized field experiences (HRSG's and conventional boiler plants) and data from erosion-corrosion studies already referenced. The index values above 1 indicate a potential for tube life degradation where an index value of less than 1, indicates no significant tube life reduction.

Model Results

Some of the model predictions or FAC potentials for specific areas are illustrated in Figures 11-14. Figure 11 plots the FAC index for three feedwater pH values against feedwater temperature. The operating conditions of the LP feedwater system are indicated within the box. An average oxygen concentration of 5 ppb and a geometric factor equivalent to a 90°bend were selected. The plot illustrates that at temperatures below approximately 180°F, the potential for FAC is very low even at a pH lower than the typical range.

Figure 12 is a plot of the relative FAC index of an economizer tube elbow as a function of oxygen concentration at three pH values. The system and operating conditions are listed in the box. The indicated temperature of 300°F is the minimum inlet temperature expected in the first economizer pass. These operating conditions represent the " worst " case. Yet no significant FAC is indicated for this region when operating in the proper pH range. Feedwater with a lower pH but higher oxygen concentration (as in oxygenated treatment) also has a low FAC index, as expected. However, a pH of 7.0 with oxygen levels below 10 ppb and turbulent flow regime (geometric factor of 0.3) indicate a potential for FAC which in fact represents field experiences as described earlier.

Figure 13 and 14 are plots representing the behavior of different alloy materials and the strong influence of turbulence. The fluid velocity in both cases is the same and purposely elevated to provide a better contrast. In the figure 13 model, the turbulence is generated by the bending motion of the fluid, where in the figure 14 model, the fluid flow is straight (vertical tube).

The following main observations can be made from figures 13 and 14. Low-chrome alloy materials are substantially less susceptible to FAC than carbon steel. However, with the appropriate fluid chemistry [6,7] carbon steel has a low FAC potential (resistant) even in those areas where velocity (15 ft/sec) and turbulence are higher. If the tube geometric characteristics don't influence or impart significant turbulence, even at high velocity, then

the FAC potential for carbon steel even at a pH of 7.0 and low oxygen levels is not significant (index less than 1). As already discussed, this is representative of field experiences as straight or vertical tubes even under these aggressive chemical conditions have not shown tube degradation from FAC while other locations in the unit experienced FAC. Obviously, these types of chemical conditions can cause other corrosion problems and should not be tolerated.

It should also be re-emphasized that the pH (controlled by ammonia or other amines) as typically measured at room temperature may not be representative or hold the normal relationship of the pH at high temperatures if organic substances or other contaminants are present in the feedwater. This was discussed in a previous section but the point is to illustrate the limitations of any of these models. In other words, just because a pH of 8.8 to 9 may be measured in the feedwater, it doesn't mean that the potential for FAC is low without having evaluated other relevant cycle chemistry parameters.

As indicated in a previous section, FAC incidences that were investigated by the author involved combined cycle plants where organic amines and oxygen scavengers (or hydrazine) were used for feedwater and LP boiler water pH control. In some of these plants, organic despersive agents were also being used in the IP/HP boiler water. Of course, this resulted not only in lower pH values due to organic acid by-products but also a very reducing environment due to the “hydrazine” high residual concentration. In this regard, it seemed worthwhile to represent these very harsh conditions by expending the model to low negative potentials (far lower than that represented by the zero oxygen concentration). Unfortunately, there isn't sufficient ORP data (field or laboratory) to even generate an index in the manner explained above. However, based on the available information and field experiences, the formulations and plot in figure 11 were modified (in a qualitative manner) to include the higher negative potential region and the results are presented in figure15. It is evident that even with a feedwater pH around 8.8, presence of residual reducing agents (i.e. hydrazine or equivalent) will increase the FAC substantially. It is also indicated, as commonly agreed, that at a pH above 9.3, FAC is minimized even in a reducing environment.

Summary/Conclusions

The FAC mechanism is a corrosion process where the mass transfer of ferrous ions from the oxide layer to the bulk fluid is accelerated by turbulence or eddy diffusion.

The potential for FAC exists in the fluid temperature range between 77°C (170°F) – 232°C (450°F), with a maximum potential at a temperature around 150°C (300°F). Principal regions in an HRSG that are within this temperature range are:

- LP Evaporator/steam drum
- IP and HP economizers and associated feedwater piping/fittings

Modification of the water chemistry has resolved or arrested FAC in those plants mentioned above. The feedwater pH (and that of the LP boiler water where applicable) must be carefully controlled and validated. Also, the use of oxygen scavengers is not recommended if the oxygen concentration is properly controlled by mechanical deaeration.

Strong alkaline treatment (high pH/strong buffer) of the boiler water including the LP boiler (where possible) prevents FAC. This is another indication that the FAC process is primarily water chemistry related.

There could be circumstances where the chemistry conditions are dictated by process steam requirements and as a result, the FAC potential may be high. In these cases, materials that contain above a minimum amount of chromium (typically above 1%) should be considered. In addition, the extent of the potential for FAC can further be limited by designing the plant cycle (separate feedwater tank/deaerator function from the LP drum) such that the LP boiler water can be treated with strong alkaline additives.

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Figure 1. FAC Related Wastage/Thinning of Economizer Stub or Tube Nipple at Economizer Header

Figure 2. Economizer Tube Bends at Inlet Header

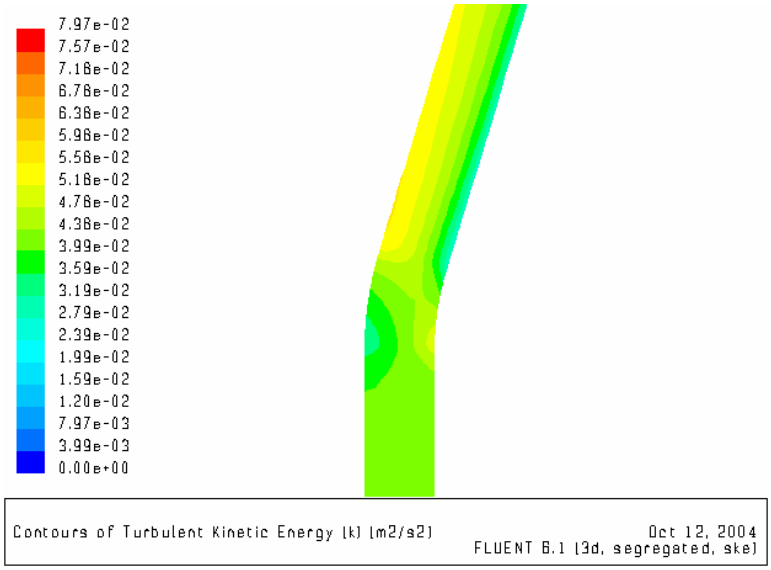

Figure 3a – Turbulence Kinetic Energy in Tube with 17° Bend

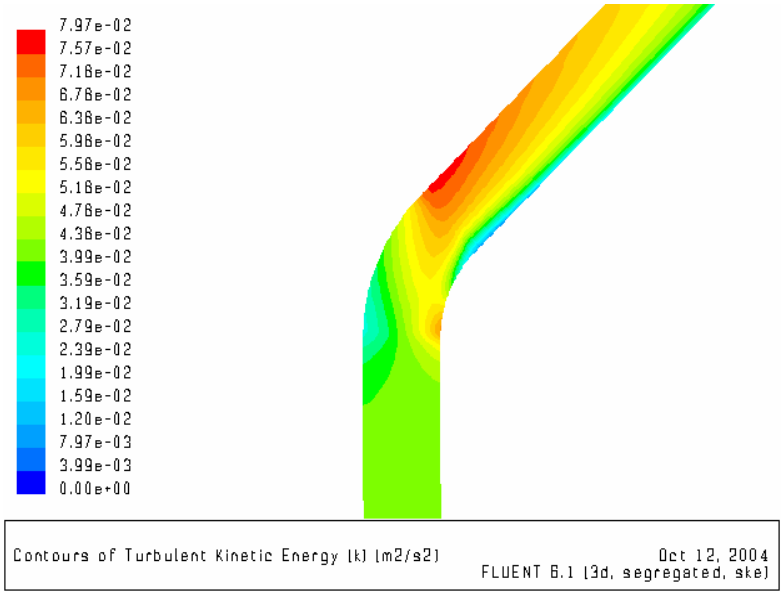

Figure 3b – Turbulence Kinetic Energy in Tube with 45°Bend

Figure 4. FAC Damage in Drum Internal. Oval Nature of Holes is First Indication of FAC

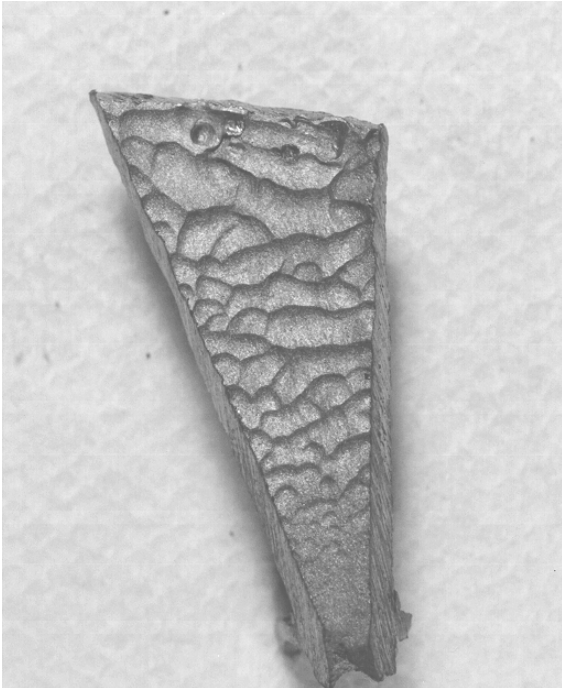

Figure 5. Scalloped Surface-Characteristic of FAC

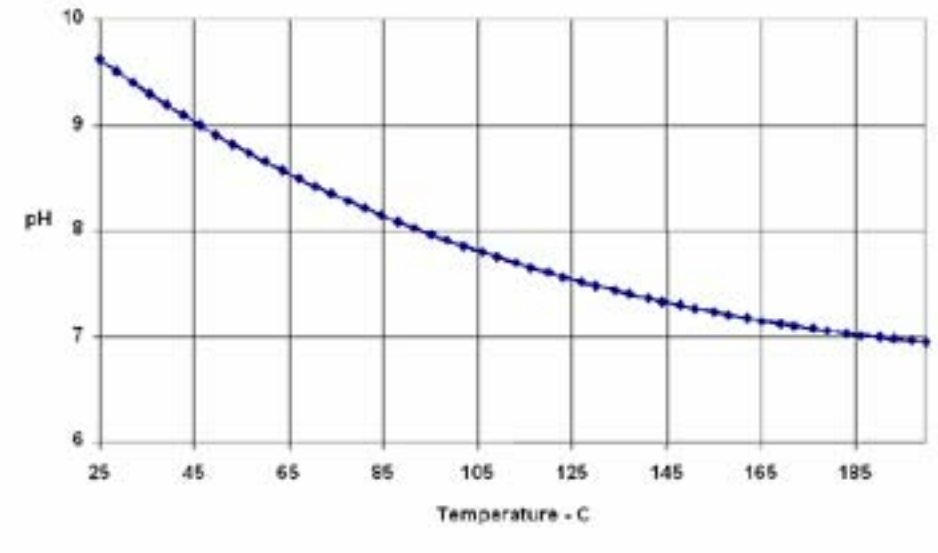

Figure 6– Effect on pH by fluid temperature with 1.5 ppm ammonium hydroxide

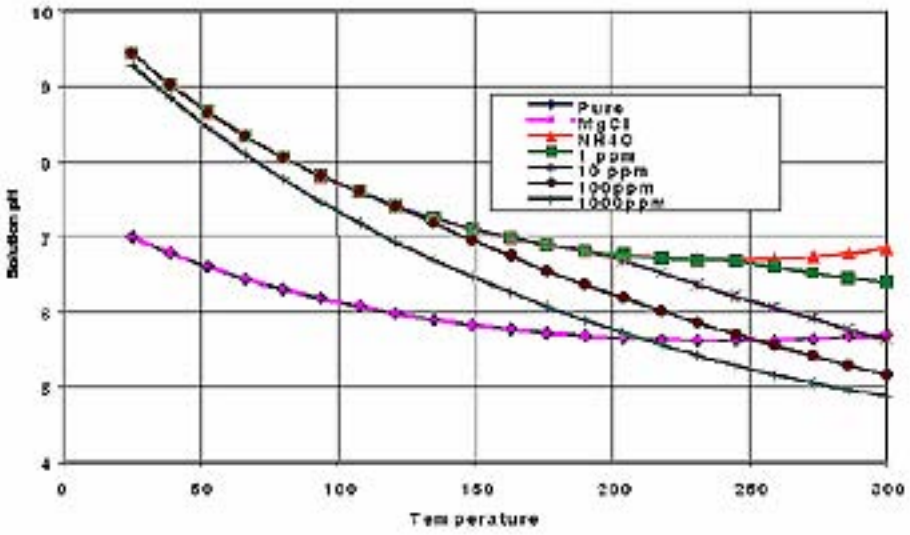

Figure 7. Hydrolysis Reactions

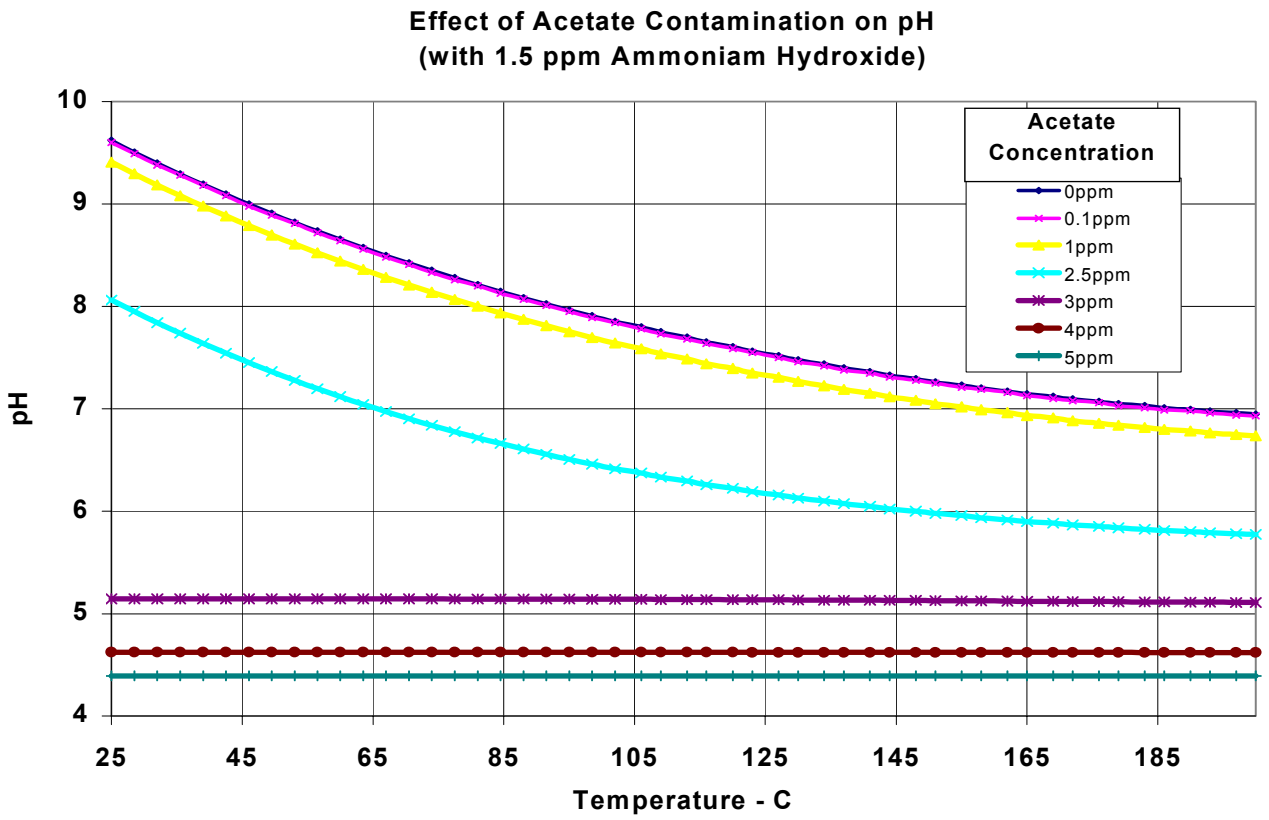

Figure 8. Effect of Organic Acid (Acetate) on pH with 1.5 ppm of Ammonium Hydroxide

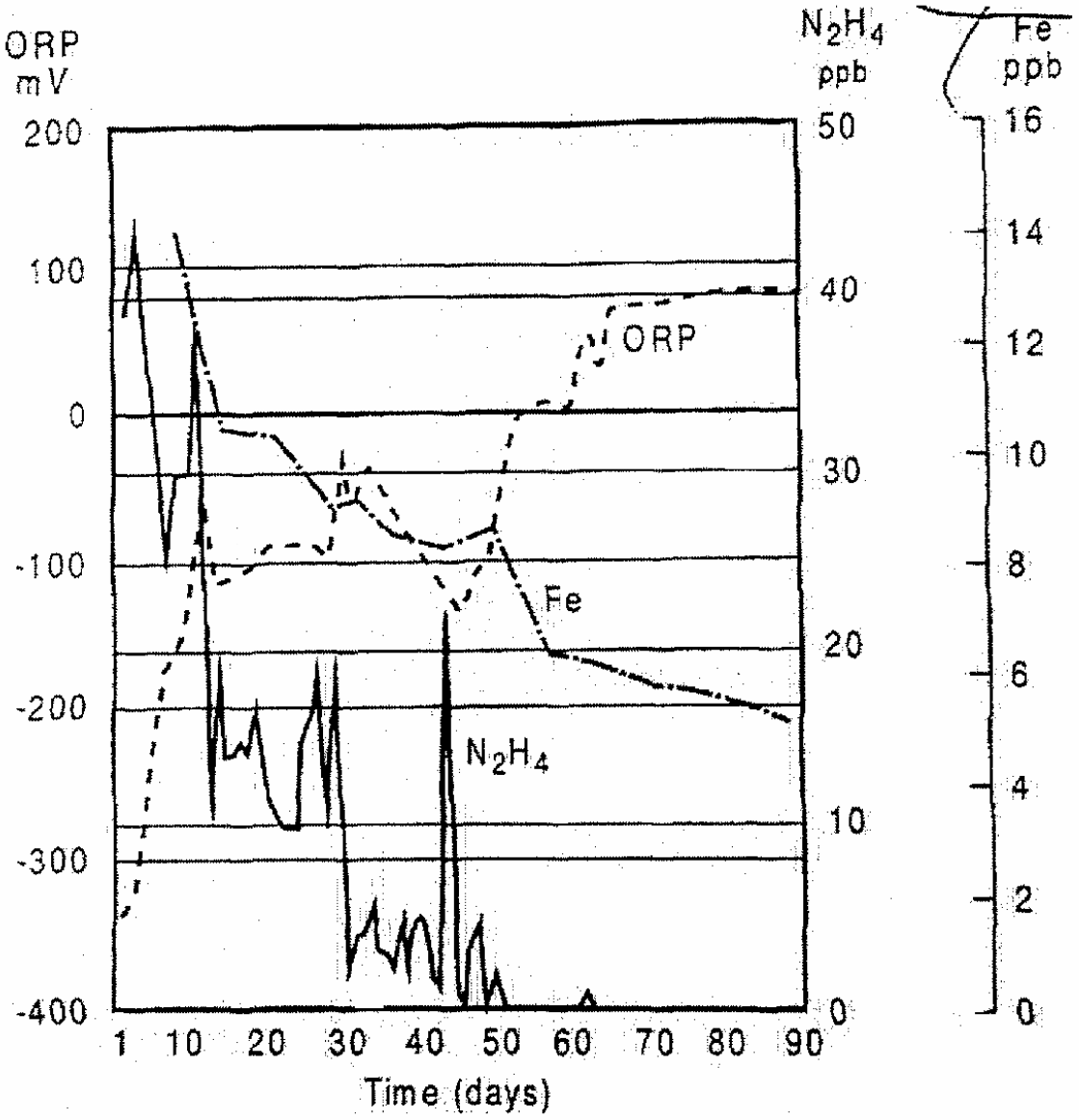

Figure 9. Relationship of ORP Vs Hydrazine/Iron Concentrations

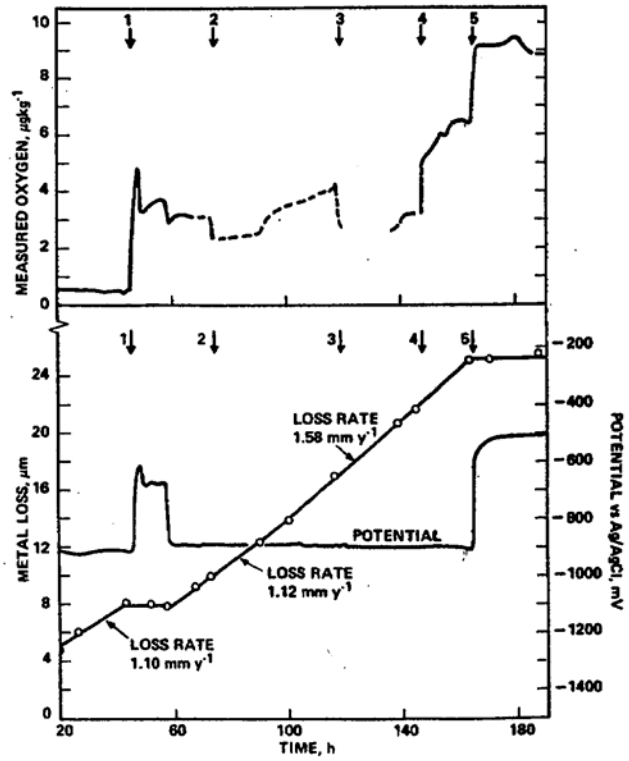

Figure 10. Oxygen Influence on FAC

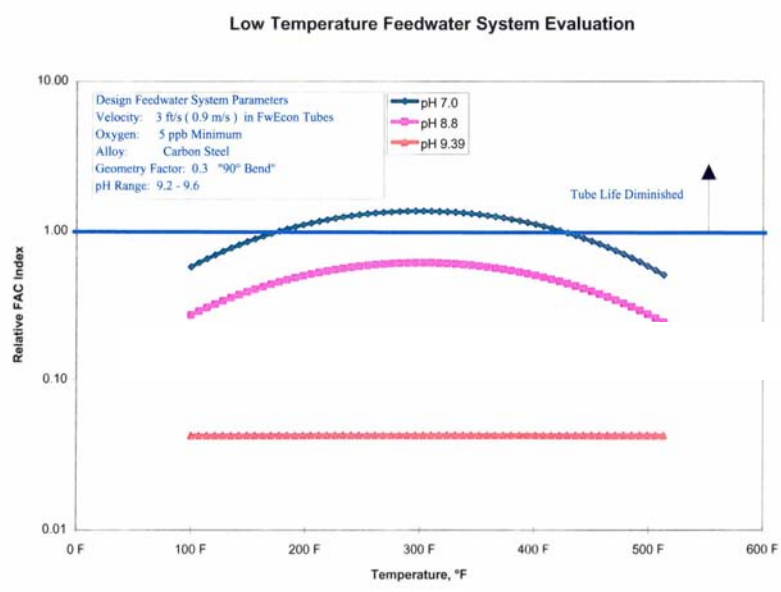

Figure 11. FAC Index as a Function of Temperature

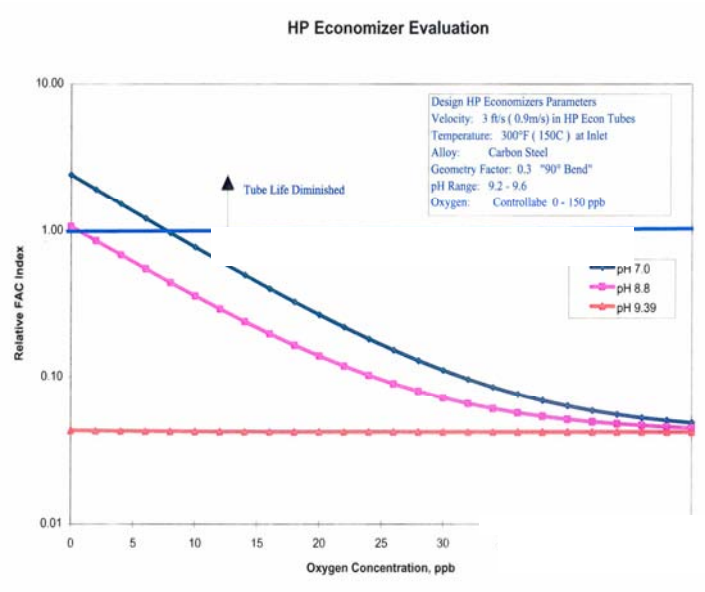

Figure 12. FAC Index as a Function of the Oxygen Concentration

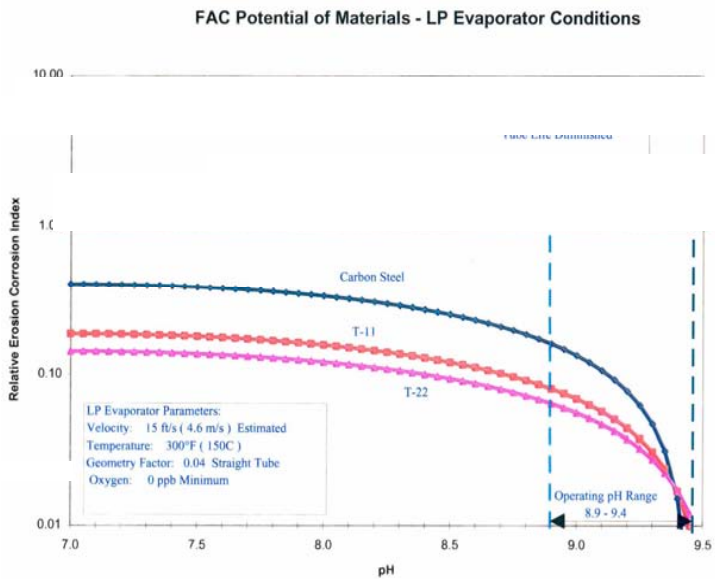

Figure 13. FAC Index as a Function of pH and Alloys

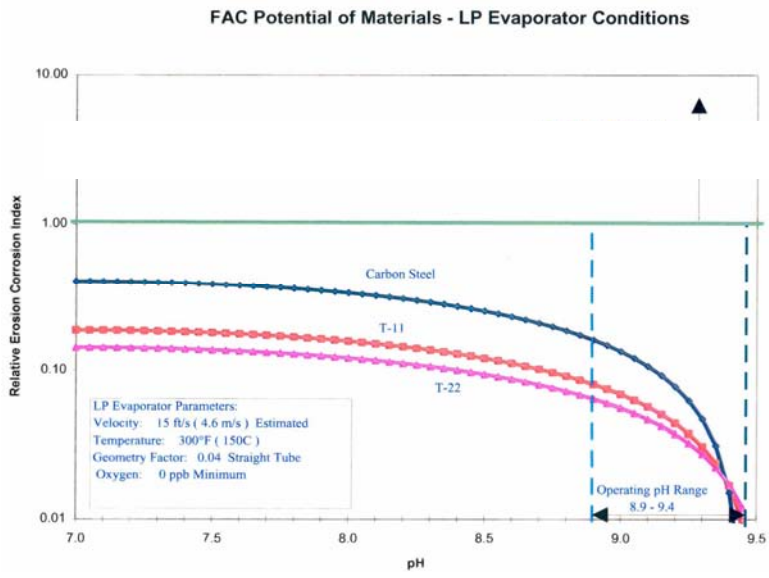

Figure 14. Same Conditions as in Figure 8 but No Turbulence Causing Factors

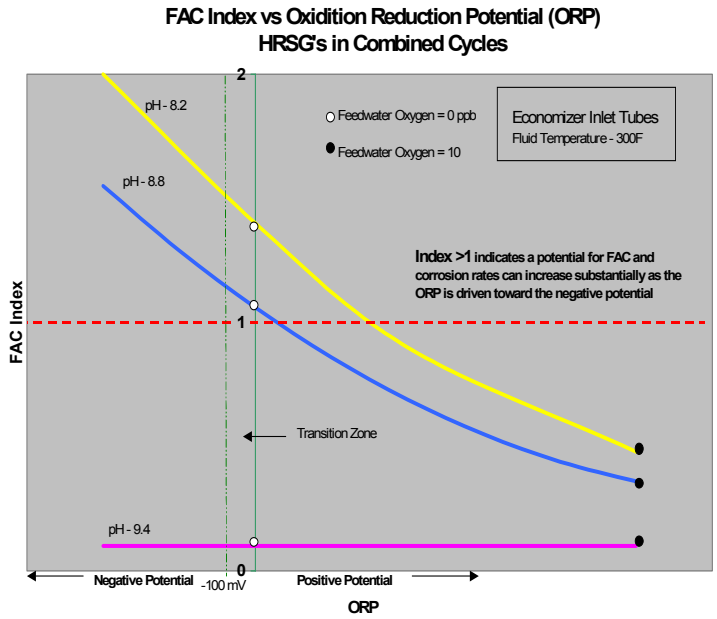

Figure 15. FAC Index Expended to Include Higher Negative Potential Range

Repair Welding Technologies For Heat Recovery Steam Generator Tubing

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Abstract

Tube failures in heat recovery steam generators (HRSGs) are often the result of high thermal stresses or thermal shock associated with cyclic plant operation. A number of premature failures have been observed both along the length of finned tubes and at attachment locations where tubes are joined to the upper or lower header. Each type of failure is expensive to correct, normally requiring repair organizations to "cut their way in and weld their way out." Poor welding access and repair practices often result in reoccurrence of the failures with existing welding technology.

This paper discusses two separate welding technologies that are being developed to address tube failures. The first technology addresses tubing failures along the length of the tube. Damaged sections of the tube are severed from the existing tube and a section is replaced via gas metal arc welding (GMAW) from the inside of the tube. A welding head specifically designed to perform this inside-out, "window-weld" repair has been designed and built by EPRI and Aggressive Equipment and is now being offered commercially. Applications include both HRSG and boiler waterwall tubing.

The second technology addresses tube-to-header attachment damage via removal of the existing stub from the inside of a header and then replaces the stub tube with a slightly oversized and tapered tube. This repair and the equipment required to perform the repair are complex in that the repair first requires cutting an access window into the header opposite of the stub tube, insertion of severing equipment, boring of the stub tube, severing of the stub tube-to-tube weld, replacement of the stub tube, and re-welding using GMAW. This repair technology is currently under development and is scheduled to be available in late 2005.

The two welding technologies identified herein will lead to significant improvements in the way HRSG tube failures are repaired by OEMs and repair organizations.

Background

Finned tube repair in HRSGs requires "cutting your way" into the tube bundle to gain access to the damaged tube, repair of the tube by replacing a short section, and then re-welding (replacement of short sections) each tube in the bundle as one works his/her way back out to complete the final tube attachment. This effort is time-consuming, costly, and normally results in poor quality replacement welds due to poor access. Furthermore, severing of un-damaged tubes is required to gain access to the damaged tube deep in the

bundle. As a result, EPRI was tasked by membership utilities with identifying an improved repair technology for performing HRSG tube repairs. Prior efforts under the Boiler Life and Availability program (P63) to develop an automated window welding device provided the basis for addressing finned HRSG tubing repair. The automated window welding device is described below prior to further discussion of HRSG tubing repair.

Replacement of tube sections in boiler waterwall applications (often referred to as window welding) is complicated by limited access to the rear or casing-side of the tubes during welding/tube replacement. Limited access often results in poor weld quality since the welder cannot see the rear of the tube. As a result, in 2001 EPRI initiated work to develop an automated welding device to improve weld quality for replacement waterwall tubing. A prototype window welding device was conceived, drawn up on paper, assembled, and patented. (1,2) Specialty Welding and Machine was hired as the primary contractor to develop the welding device.

The approach taken to design and assemble the device was considerably different from any approach currently taken by industry. The design utilized pre-fabricated 16-inch long sections that were prepped on both ends and contained an access window (Figure 1). Tube welding was performed from the inside diameter (inside out) of the tube, as opposed to the conventional outer diameter welding. Actual welding was performed remotely using a two-piece weld head that could be consistently pre-placed inside of the tube at a specified distance from the weld joint location. (Figure 2) A Miller 304A was employed for the power supply. (Figure 3) Figure 4a through 4d provide a pictorial view of the prototype welding device insertion into a tube. The access window can be completed using GMAW or GTAW.

Once the prototype was assembled, EPRI Fossil Repair Applications Center (FRAC) staff spent a few weeks testing and refining it before introducing the prototype to the market. The device was sent, along with an FRAC engineer and an engineer from Specialty Welding & Machine to Kansas City Power & Light for additional testing specifically to determine the ruggedness of the welding device. Two limitations were immediately identified. One, the copper tube through which the wire was fed was not sufficiently rigid to allow repeatable field welding. Two, the electronics of the device could be improved considerably. In spite of these short comings, FRAC staff believed the prototype concept was sound.

FRAC staff decided to approach a field welding service vendor to help ruggedize and improve the design of the existing prototype. Carolina Energy Solutions was contacted due to the fact that they not only are a service repair organization, but also because of their equipment manufacturing service arm, Aggressive Equipment. It was believed that their expertise in equipment manufacturing could assist in further refinement and development of the window welding device. Additionally, their field service organization could provide continuous feedback to the manufacturing arm to provide continue improvements as experience was gained.

After an agreement had been reached to work together on improving the prototype, the prototype device and drawings were forwarded to Aggressive Equipment. The device was completely disassembled and reconfigured from a two-piece welding head to a single-piece head. Further discussion is provided later in this paper concerning this topic.

Introduction

Concurrent to the prototype welding device development, EPRI began assembly of a document on "HRSG Material Selection and Repair Guidelines—1004875" (1). During assembly of this document and in working with several HRSG vendors, tubing repairs were identified as an area that needed better welding equipment to improve installation/repair quality. Two tubing-type repairs were identified:

- *Repairs on tubing away from the upper or lower headers*. This form of repair requires "cutting your way in and welding your way out." It often results in poor quality tube welds due to access limitations on rear side of each tube. "Mirror welding" is commonly employed on the back side of each tube. Replacement sections are commonly utilized wherein a minimum of two OD welds are required.
- *Repairs at tubing-to-header attachments*. This form of repair requires a similar approach in "cutting your way in and welding your way out." Another approach often used is to plug the tube from the inside of the header. Of course, this reduces plan efficiency as that particular tube is essentially removed from service.

As a follow-on to the Guidelines, EPRI staff began to investigate ways to improve the welding technology to address these two forms of repair. For the tube welding application, it was believed the window welding device could, with a few slight modifications, be employed for HRSG tube-to-tube (replacement of a tube section) welding applications. During the first half of 2004, EPRI worked with Progressive Equipment to improve the current window welding device and to make incremental changes which would enable it to be used for HRSG tubing applications.

Beginning in April 2004, EPRI also began to conceptualize a method for repair of tubing-to-header attachments. A repair approach was identified and a welding equipment vendor (Encompass Machines Inc.) was selected to develop a second welding device. Further discussion regarding progress on this equipment development will be provided later in this discussion.

Tube-to-Tube Welding Repairs

As mentioned above, the prototype window welding device was forwarded to Aggressive Equipment, disassembled, and reconfigured from a two-piece welding head to a single-piece head. The re-design, still made use of the pre-fabricated replacement tube (including the pre-placed window—see Figure 1), along with the GMAW process. The

weld was also completed from the inside diameter of the tube (welds at top & bottom). By reconfiguring the welding head to a single-piece design, the pre-fabricated replacement tube length was also reduced to 12 to 14 inches. As before, an inverted (inside out) weld prep was employed.

The single-piece welding device (now referred to as the *ID Tube Welder*) shown in Figures 5 and 6 makes use of alignment collars that are secured within the replacement tube both above and below the window. These alignment collars can be sized for 1" I.D. to 3" O.D. tubes, thus offering a wide range of capabilities regardless of HRSG or waterwall tube size. Once inserted into the tube window, a unique handle design enables the bottom collar to be centered and secured (or retracted) in one single motion. The handle is spring-loaded to allow for easy insertion or retraction. This feature allows for a reduced working envelope and enabled the device to be reduced from a two-piece design to a single-piece device.

Another unique feature of the new *ID Tube Welder* is the height adjustment. A height indicator enables the user to determine vertical position of the weld head thus allowing incremental changes when necessary to better position the weld torch. Height adjustments can be made to $\pm$ 3/8-inch for multi-pass welding applications. Gas coverage is provided for high alloy welding applications via the collet just below the weld head. Gas coverage can be maintained from pre-purge to post-purge and throughout the welding process. Rice paper can be placed within the existing tube to provide a boundary out-board of the weld region.

Throughout the development process, EPRI and Aggressive Equipment stressed the need for the *ID Tube Welder* to be welder friendly and low cost. The "welder friendly issue" was addressed in several ways. The weight of the overall system was kept at a minimum using: 1) a light-weight GMAW power supply which could be placed with 10 feet of the weld region, 2) a push/pull wire feeder, 3) a compact pendant board, and 4) a light-weight aluminum-based ID weld head. Low weight makes the welding system more user-friendly and allows the welder to carry the system directly to the problem location. Additionally, the GMAW process was employed and the pre-fabricated tube and window were standardized. This generates repetitive welds over and over again with little change by the welder.

Finally, the welding system was kept simple: 1) No cameras were employed, 2) up-slope and down-slope are used to taper for appropriate weld conditions, 3) incremental position changes can be made easily using the height adjustment feature, and 4) the weld head automatically and consistently locks within the center of the window thus reducing the need for alignment by the welder. Single or multi-pass welding is readily achievable. For thicker tubing applications that require multiple pass welding, the ID Tube Welder allows precise placement of weld beads using the height adjustment feature. Repeatable welds are readily achievable using this feature.

The second item stressed by the team was to keep the cost of the system low so that each plant could afford to have a window welder on-site to address tubing failures

immediately when they occur. The team stressed that the device should be kept near $20K (including the power supply), otherwise the cost may prove prohibitive on an individual plant basis.

The ID Tube Welder was introduced in June 2004 at the EPRI Welding & Repair Technology for Power Plants Conference. Figure 7 provides a view of both the OD and ID of a sectioned weldment. Several demonstrations have been planned for the summer/fall of 2004 at plant sites.

Tube-to-Header Attachment Repairs

The second form of repair identified during the preparation of the HRSG Material and Selection Guideline was tube-to-header attachment repair. This form of repair is often more difficult than conventional tube repairs. As a result, such failures are often left in place and simply plugged. Figure 8 provides an example plug weld configuration. Plugging requires removal of a window within the header 180 degrees away from the stub tube attachment location, machining and insertion of a tube into the damaged plug bore, welding of the plug into place, and then re-installation of the window.

Selection of a repair methodology is complicated by the number of different attachment configurations used by industry. Tube-to-tube attachment weld designs used by original equipment manufacturers (OEMs) include:

1) partial penetration welds
2) full penetration welds
3) forged nipples with full penetration welds
4) separate nipples and full penetration welds between nipple and header and to tube

Examples of each of these weld designs are provided in Figure 9. Advantages and disadvantages for each form of repair are described in Reference 4. Following several internal discussions, EPRI identified an approach applicable to all four designs.

The EPRI approach considers a much more radical approach to address HRSG header-to-tube damage than is currently used by industry today. At present, repair vendors and OEMs address tube attachment damage from the outside of the header. This requires cutting your way past a number of tubes in a tube bundle, performing the weld repair from the outside of the tube (often requiring partial tube replacement), and then re-welding all of the tubes that were cut to gain access to the header-to-tube damage. This approach (commonly referred to as "cutting your way in and welding your way out") is time consuming, costly, and more often than not, results in poor weld quality due to limited accessibility.

The EPRI approach looks to address the header-to-tube damage from the inside of the header as opposed to "cutting your way in and welding your way out." In this approach, an access location (hole or window) is machined from a location 180 degrees away from the damaged area. A machining device is inserted into the inside of the header to sever

the tube at a location approximately 2-4" away from the OD surface of the header. The remaining tube is then removed by cutting (boring or EDM) the tube away to a diameter slightly greater than the original diameter of the tube.

Next, a slightly oversized and tapered new stub tube is inserted into the over-bored location. The purpose of the taper is to provide a thicker tube-to-header transition, while allowing the tube to be re-joined by a normal welding process. The over-bored hole also accommodates complete removal of the existing tube and attachment weldment. Figure 10 provides a schematic of the new tube-to-header design. The stub tube may also contain a transition to improve fit-up between it and the existing tube thereby improving joining.

The next step required is to join the new stub tube to the existing tube which has been re-machined (prepped) for welding using reverse prep. This is accomplished by inserting an internal welding device (GTAW or GMAW) and welding the tube from the inside. This secures the stub tube in place. A second and final weld is required to secure the stub tube inside the header. This weld is made at the inside diameter surface of the header using automatic or manual equipment. Another possible step in this sequence would also include roll expansion of the stub tube against the header bore. The individual steps to perform this overall inside diameter repair are provided in Figure 11.

EPRI has contracted Encompass Machine, Inc. to assist in the development of the tube-to-header attachment repair device. Actual work was initiated in late July 2004 and has been separated into individual modules due to the complexity of this repair process. Specific equipment and tooling criteria have been identified and work is underway to complete the first module by October 2004.

Summary & Conclusions

- Tube damage and attachment damage have resulted in a considerable number of failures in HRSG equipment. Power plant owners have asked EPRI to assist in developing less obtrusive and more consistent methodologies to perform these two forms of repair. Such equipment could be used by power plant personnel, repair vendors, installers, or OEMs.
- A patented *ID Tube Welder* has been prototyped, further enhanced, and now commercialized for performing both waterwall window welds and HRSG tube-to-tube weld repairs.
- The *ID Tube Welder* significantly reduces time to perform window welds (or HRSG tube-to-tube welds) over conventional SMAW-type repairs. Furthermore, it provides power plants with a consistent, rapidly deployable, method to perform repairs and eliminate welder error.
- A tube-to-header attachment repair methodology has been identified to address all four attachments now offered by OEMs. Equipment development has been initiated to first develop a prototype and to eventually commercialize this technology.

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2) U.S. Patent 6,596,957 B2, Method and Apparatus and Prefabricated Replacement Tube for Localized Waterwall Repair, July 22, 2003.
3) Aggressive Equipment Web Site photographs. http://www.aggressive-equipment.com/new/idtubeweld.html
4) EPRI Report 1004240, Delivering High Reliability Heat Recovery Steam Generators, March 2003, pp 7-58 through 7-59.

Acknowledgements

The authors wish to thank R. Bryant, R. Phillips, L. Tellone, and D. Thorton from Carolina Energy Solutions/Aggressive Equipment for their input, insight, and development capabilities in bringing the tube-to-tube welder to market.

We also want to thank members of the Boiler Life & Availability program (P63) and R. Tilley who manages this program for funding and pursuing advanced welding technologies for waterwall applications that eventually led to the development of the *ID Tube Welder* discussed herein.

Finally, we would like to thank James (Buster) Hales (Specialty Welding and Machine) for his contribution in the development of the prototype tube-to-tube welding device.

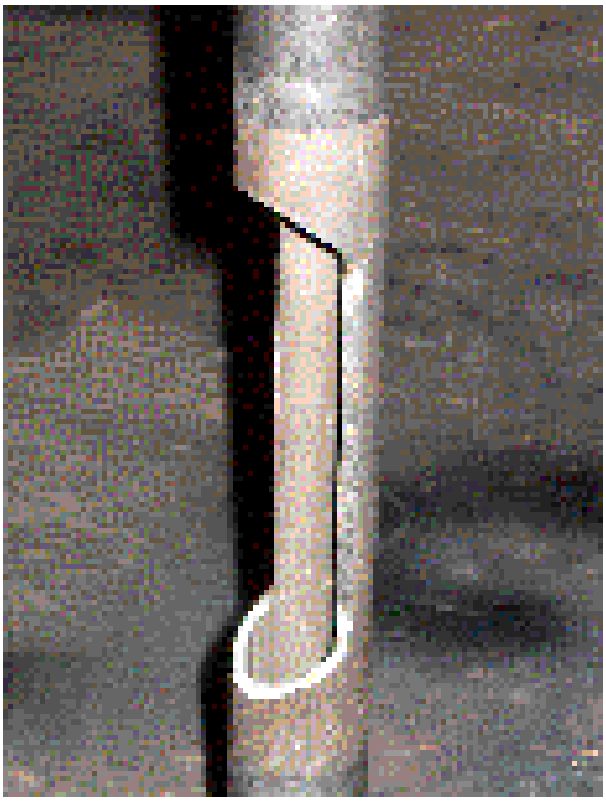


Figure 1. Pre-fabricated tube that includes inverted weld preps (weld from ID) and along with a window in the center of the tube.

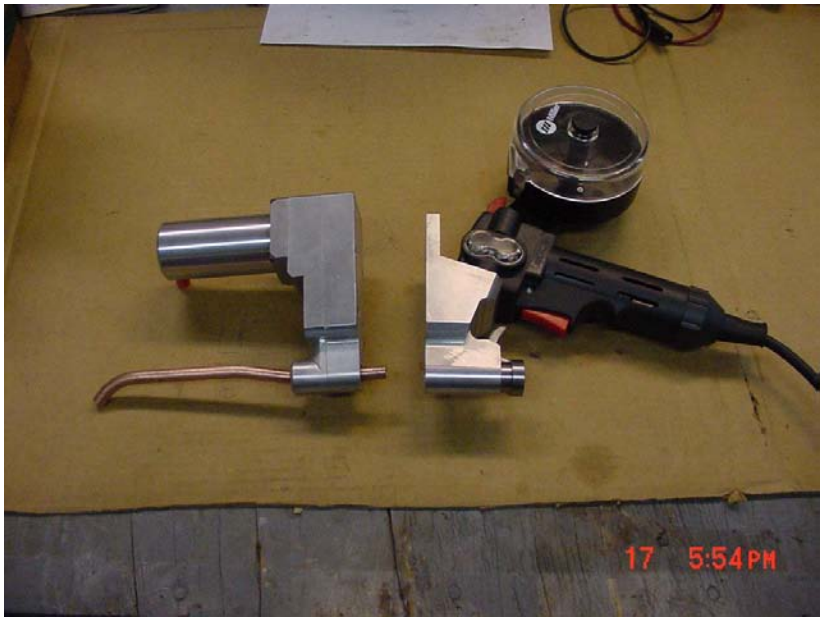
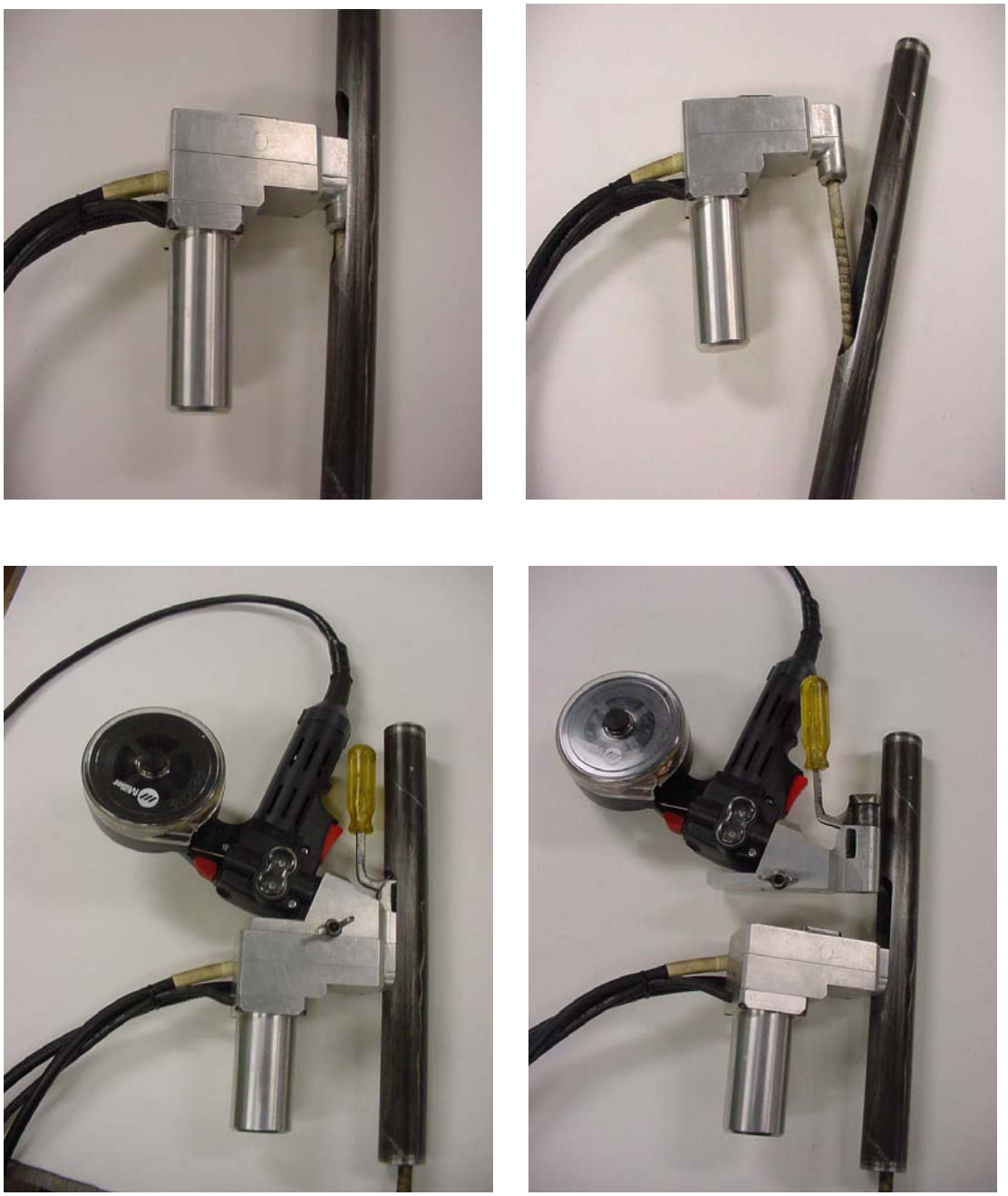


Figure 2. Two-piece prototype window welding system developed by EPRI and Specialty Welding and Machine.

Figure 3. The protype window welder inserted into a tube along with the Miller power supply.



Figures 4a-d. Photographs demonstrating insertion of the two-piece welding prototype into a tube.

Figure 5. ID Tube Welder (developed collaboratively by EPRI and Aggressive Equipment) inserted into a tube for welding.

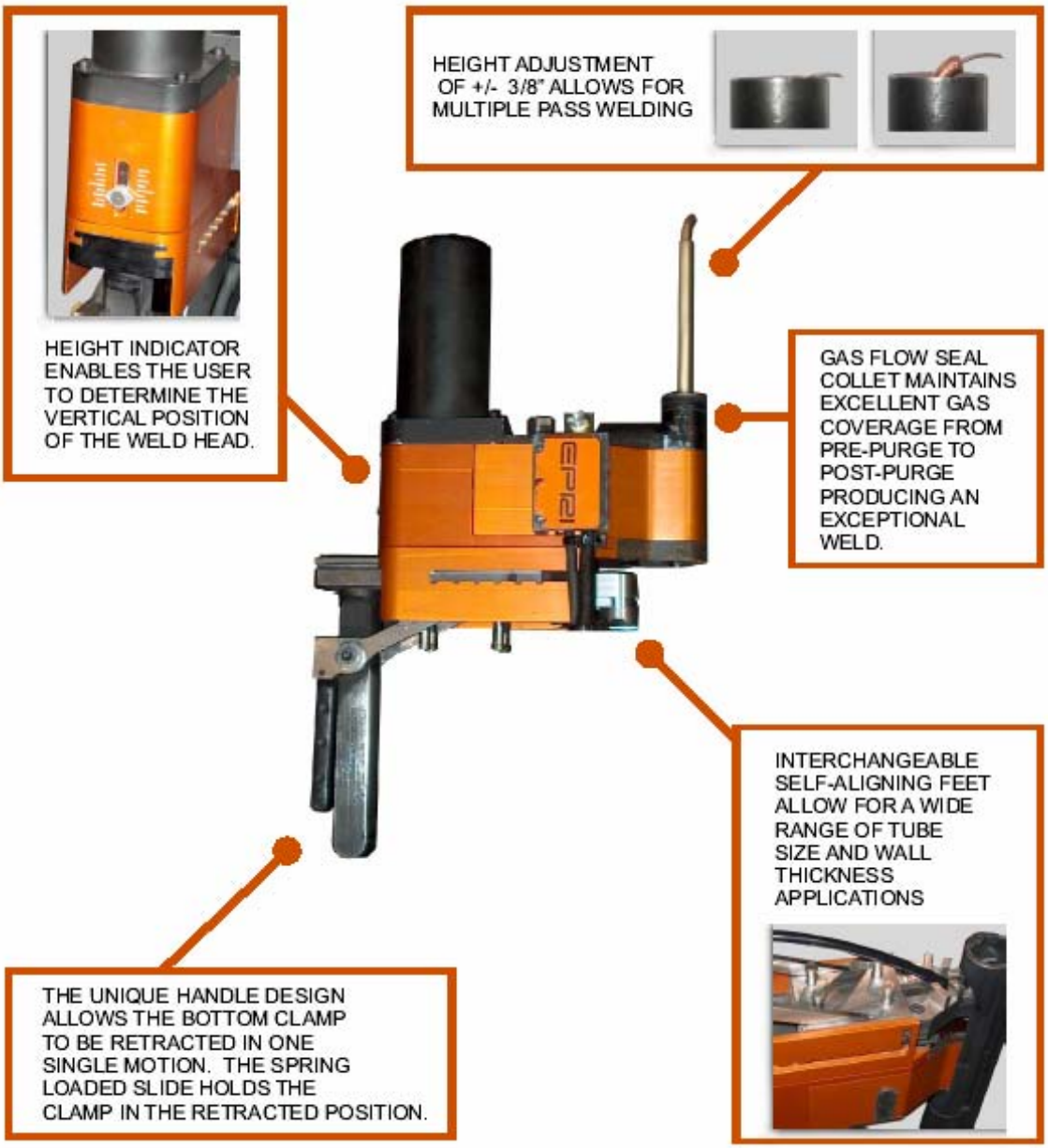


Figure 6. Another view of the ID Tube Welder after removal from a tube.

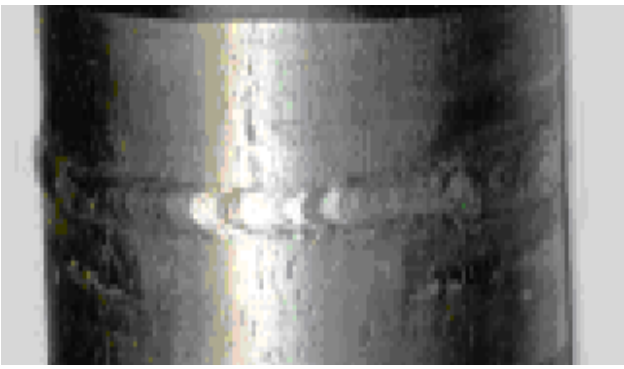


Figure 7. OD view of a completed weld

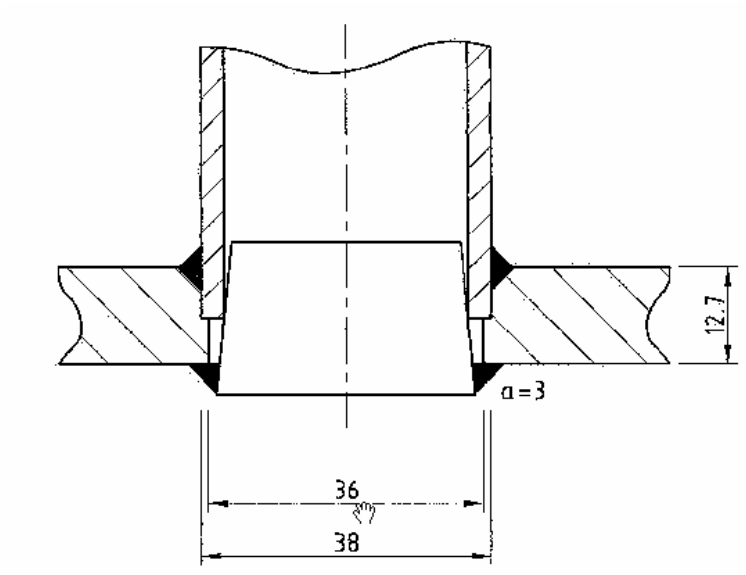


Figure 8. Plug Design

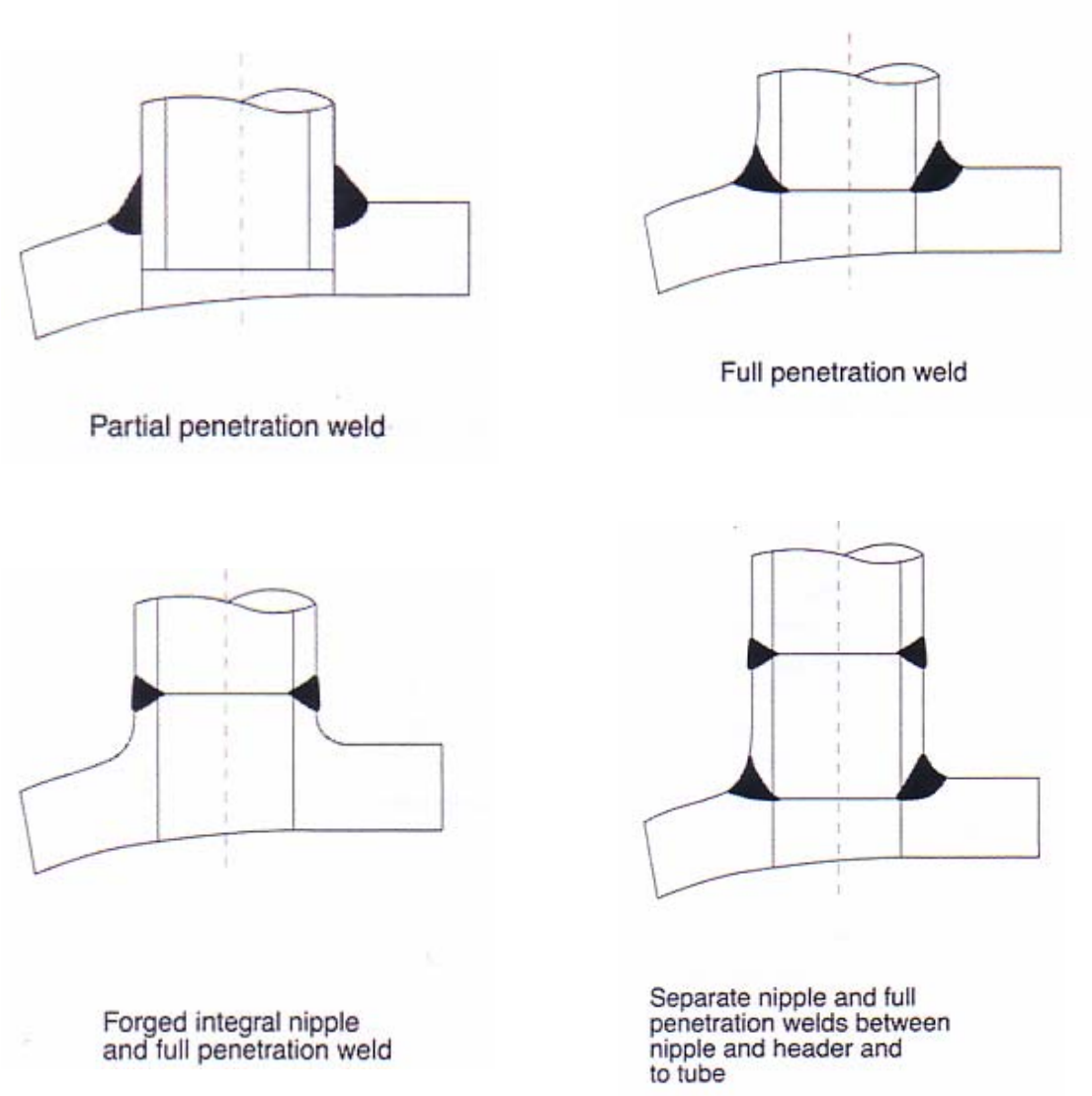


Figure 9. Example HRSG header attachment configurations.

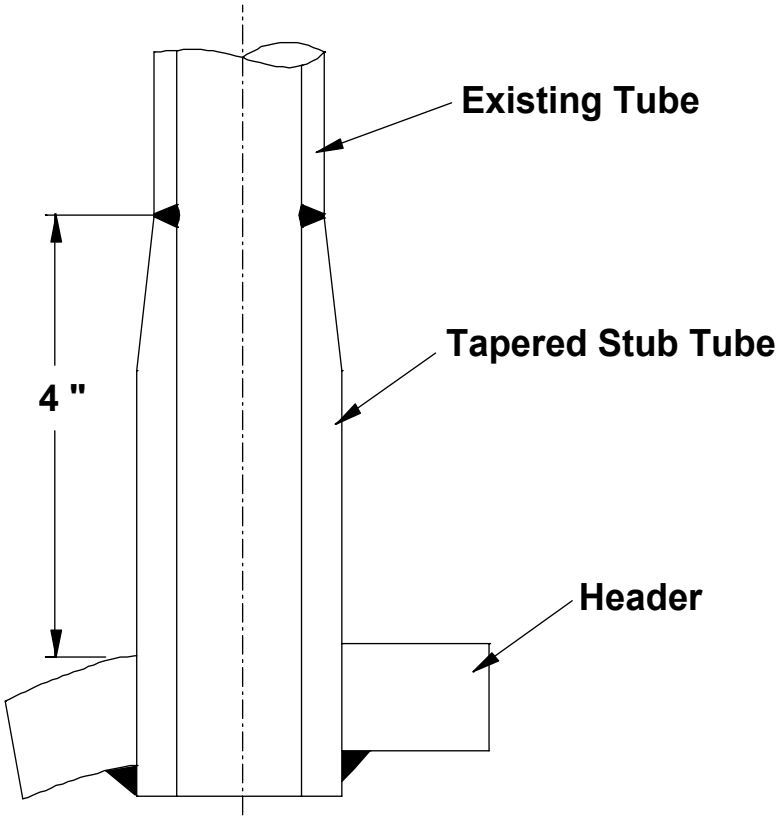


Figure 10. Tapered Stub Tube Used In EPRI Repair Method.

Figure 11. Anticipated Steps For Repair of Header-to-Tube Damage From The Inside Diameter of the Header.

1. Mount a saddle-base to header to position tooling.

2. Remove access window from header opposite of damage location

3. Insert device (through header tube bore) to sever tube at weld joint on OD of header (~2 to 4-inches above).

4. Bore or EDM header to same diameter of tube OD (+++). Also remove any remaining weld from OD region. Chamfer

5. Remove remainder of severed tube through ID of header

6. Insert prep tool to prepare remaining tube (backwards prep)

7. Insert preheating device

8. Insert new "thicker & tapered" stub

9. Using ID weld head, perform weld between existing tube and new stub tube.

10. Roll expand new stub to header (if required).

11. Perform full penetration seal weld at bottom of new stub-tube

12. Insert alignment device to align existing tube with new tapered stub tube

13. Remove ID weld head and then re-weld header window.

SESSION 8: Mechanisms #3 – Fireside

Chairman: P. James, EON-UK

BOILER TUBE EROSION REDUCTION USING THE COLD AIR VELOCITY TESTING TECHNIQUE

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Drennen Engineering, Inc.

Barry Dooley
EPRI

Abstract

Boiler tube failures (BTF) due to fly ash erosion are one of the leading single causes of availability loss in fossil boilers. The damage, which can be very localized, has led to expensive and lengthy forced outages. The problem is currently being managed by many utilities through maintenance activities that are put into effect each time a boiler is taken off line. This paper describes a technique for identifying and systematically eliminating the cause of erosion related BTF's, summarizes work over the past three years and highlights current activities.

Background

Serious boiler tube erosion is generally the result of gas and ash flows that exceed design conditions. It is most often associated with designs features of cavities, pendants and banks that encourage flow to move from one region to another, thereby exceeding local average conditions. Excessive fly ash flows are often due to centrifugal separation and sootblowing. It is the combined effect of higher solids loading and higher gas flows that lead to the most serious erosion. Other changes that contribute to BTF and increased erosion would include: reduced fuel quality, fuel firing equipment, above design firing rates, modifications to pressure part and ash plugging.

Reducing or eliminating serious erosion problems requires an evaluation of unit operation, erosion history, physical design and a detailed velocity mapping in the backpass areas of concern. By conducting a Cold Air Velocity Test (CAVT), airflow distribution is mapped throughout the backpass and/or in areas prone to fly ash erosion. Test results, along with erosion patterns and plant operating data are used to select and locate flow control devices to redistribute both gas and fly ash, and therefore

lower erosion potential. This technique has been used very successfully in US and international utilities to provide long-term solutions to BTF from fly ash erosion. These techniques, results from selective units and other historical information have been documented extensively in several reference papers and reports. (1, 2, 3, 4, 5). The remainder of this paper provides results from a recent program that demonstrate the effectiveness of the CAVT technique.

Summary of Erosion Control Projects

Erosion control programs have been performed at:

- 32 US utility power plants ranging in size from 173 to 1300 MW at 22 utilities. A similar quantity in Canada.
- International utility power plants – 7 in India, 1 in Hong Kong
- 9 industrial power boilers ranging in size from 150,000 lb/hr to a 550,000 lb/hr steam including three CFB boilers and one refuse/coal fired unit.
- 2 Computer Models for domestic units where a CAVT was not possible due to schedule limitations.

In addition to backpass erosion, backpass plugging from ash carryover and gas bypassing around horizontal banks has also been addressed with flow controls. Results to date have been mostly positive, with most units reporting significant decreases in outages due to fly ash erosion in the backpass. One utility and one industrial unit reported a decrease from 6 or more BTF's per year to less than 1 per year following installation of controls for redistributing fly ash and reducing local peak gas velocities.

Recent Activities

An EPRI sponsored erosion control program was recently concluded at an Indian power plant. The initial CAVT was performed in 2001 with the recommended controls installed in 2003. A follow-up CAVT was performed at the end of the installation outage to evaluate performance of the new flow/erosion controls. Key results are presented in this paper.

India's first coal fired boiler of 500MW was commissioned at the Singrauli Super Thermal Power Station on Dec 23, 1986. Steam generating units at this site are CE/BHEL design with single drum, dry bottom, controlled circulation, single reheat, tilting tangential, pulverized coal fired boilers. Boilers are designed to produce 1725T/H of main steam flow at 178 ksc / 540°C, with reheat flow of 1530T/H at 43.44 ksc / 540°C. Coal for this unit has a HHV of 4000 kcal/kg with 28% ash and 20 percent moisture.

Since commissioning, the boiler was plagued with high rates of fly ash erosion to assemblies near the sidewalls, at the LTSH supply tubes near the fork bends and to the economizer banks, especially in the rear section, Figure 1. Through 2001, there were 54 tube failures since commissioning with 11 identified as fly ash erosion related, roughly 20 percent of the total failures. Erosion counter measures included replacement and installation of shields and cassette baffles. In spite of implementation of various protection systems, high rate of erosion due to fly ash could not be eliminated.

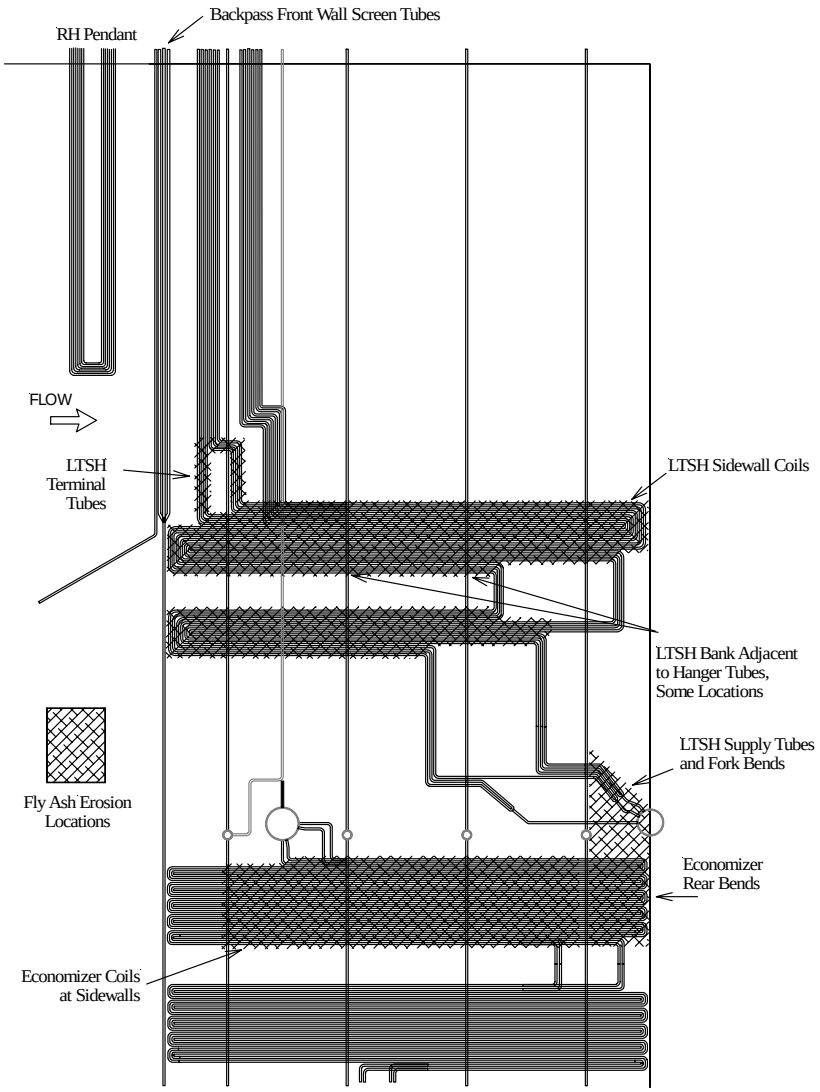

Figure 1
Side View w/ Fly Ash Erosion Locations

CAVT With Flow/Erosion Controls Installed

For the CAVT, FD and ID fans were set at 80% normal flow. To get a representative sample, about 100 measurement points were selected for each of the measurement planes 1 thru 5, identified on Figure 2. Velocity measurements were made with hand held flow meters (ALNOR 6000AP Velometer) between the first row of tubes at the inlet or outlet of each bank and at the side, front and rear wall gaps. Data from the CAVT were converted to normalized velocities relative to plane average and also to equivalent MCR gas velocities.

The installed flow/erosion controls are shown in Figure 2 and described in the following sections along with test results form the initial and post installation CAVT's.

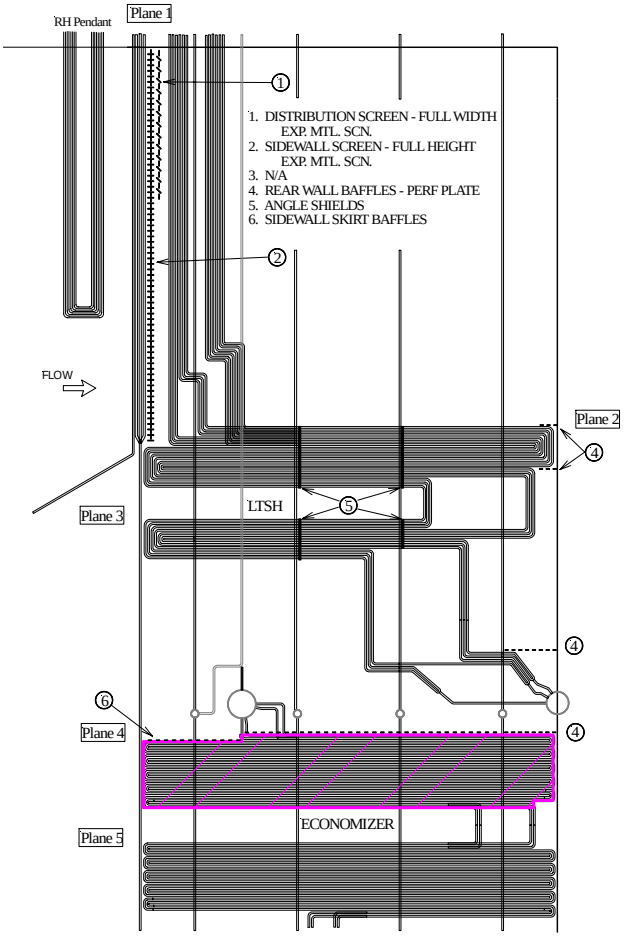

Figure 2
CAVT Test Planes and Recommended Flow/Erosion Controls

Distribution Screens at Backpass Entrance

Standard expanded metal screens (SEMS)[1] were installed on the backpass entrance screen tubes to reduce fly ash loading along the rear and side walls. SEMS have strands that can be used to redirect gas and fly ash flow. In the upper region of the backpass inlet, screens are oriented to deflect fly ash down to reduce ash loading in the rear section of the backpass. Without screens, large ash particles (>1000 micron) can reach the rear section by centrifugal separation as flow turns into the backpass. Screens at the sidewalls are oriented to deflected flow away from the sidewall.

Distribution screens are primarily intended to intercept fly ash particles and change their trajectories to lower solids loading along the sidewalls and rear section of the vertical backpass. Flow is reduced near the screens, but returns to pre-installation flows a few feet downstream of the screens.

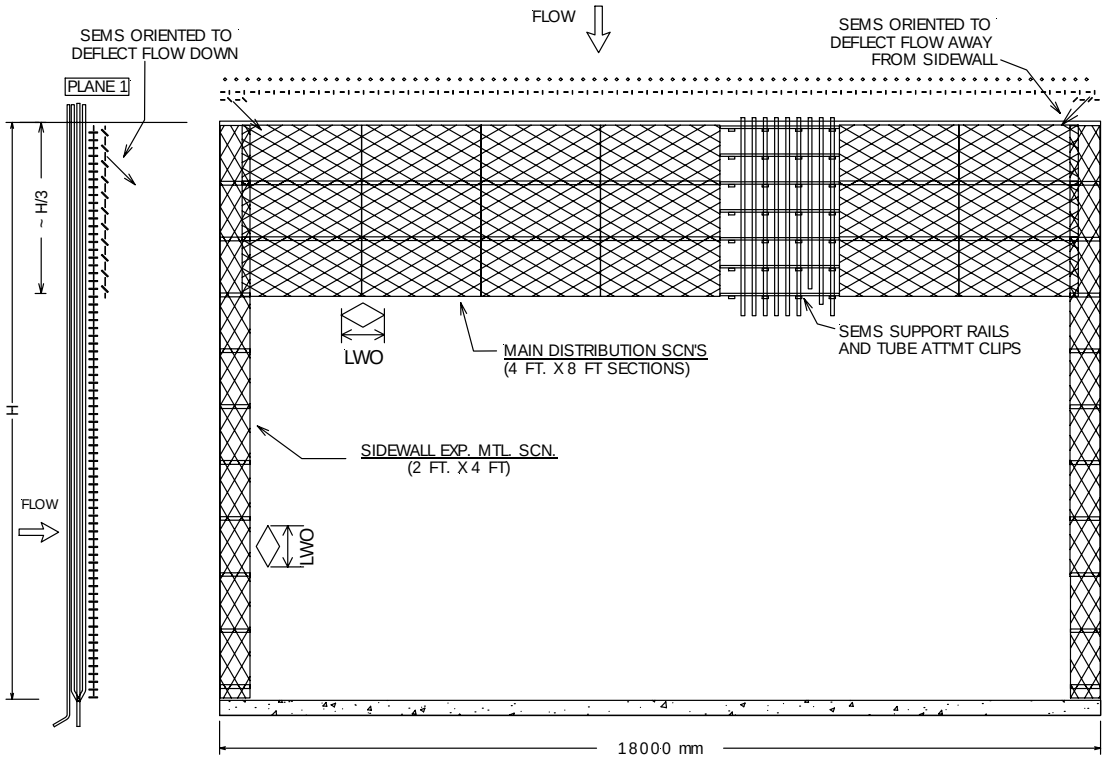

Figure 3
Recommended Flow/Erosion Controls at Backpass Inlet

[1] Compared to Flattened Expanded Metal Screen

For the vertical plane at the backpass entrance, Normalized Velocities are shown in Figure 4. Velocity profiles for the original and follow-up CAVT's are similar for the lower 80 percent of the plane; however, several locations are higher than the original test, which may indicate flow has increased slightly in the center of the plane. At the top of the plane, velocities are lower due to the presence of expanded metal distribution screens.

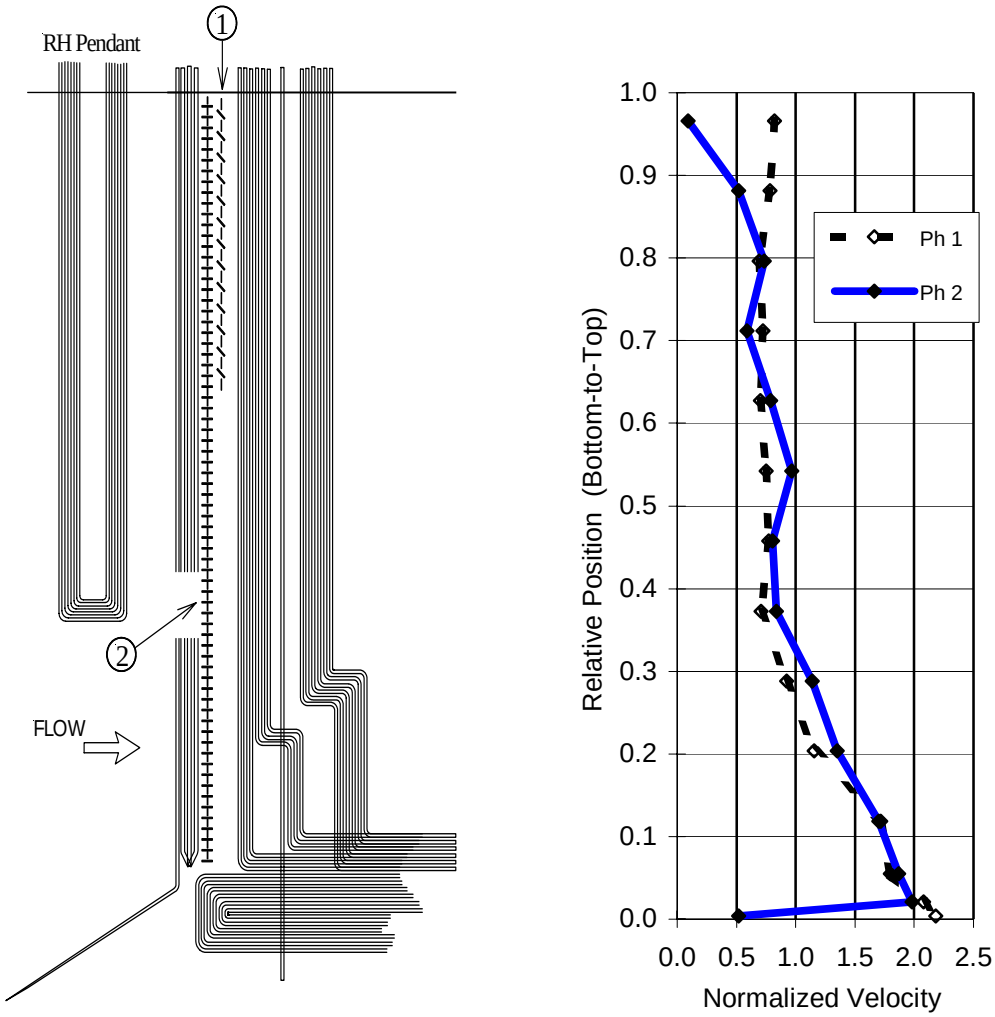

Figure 4. Normalized Velocity Profile at Backpass Entrance Screen Tubes vs. Relative Position Bottom-to-Top

For the vertical plane at the backpass entrance, the plot of normalized velocities for side-to-side flow is shown in Figure 5. Velocities in the center of the unit are similar for both original and follow-up flow tests. Flow at the sidewalls is lower for the follow-up test because of screens at the backpass entrance. These screens are oriented to deflect flow away from the sidewalls to lower fly ash loading there in the vertical pass. Gas flow a few feet down stream of the screens would return to pre-installation levels, but with some of the fly ash disengaged. Additional protection is provided to downstream tube assemblies with velocity reducing baffles at the sidewalls.

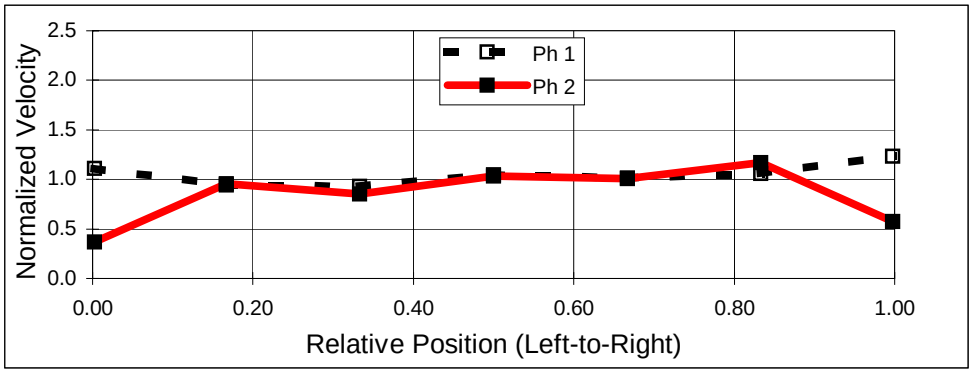

Figure 5. Normalized Velocity Profile at Backpass Entrance Screen Tubes vs. Relative Position Left-to-Right[2]

LTSH BANK

Perforated plate baffles were recommended for the inlet and outlet of the LTSH bank to lower velocities in the rear section. This area would have slightly higher flow due to fewer tube rows plus the gap at the rear wall (lower flow resistance). Above average flow and higher solids loadings, due to centrifugal separation as flow turns into the backpass, leads to above average erosion rates.

Originally, flow was more than 1.5 times plane average near the rear bends. With the new baffles installed, velocities in the rear section are below average by more than 25 percent. Lowering velocities to bank average or slightly lower would normally be sufficient to provide long-term relief from fly ash erosion. As there were serious wear here in the past, the additional reduction in gas flow should guarantee very few problems in the future.

[2] Looking downstream, Left is on left side.

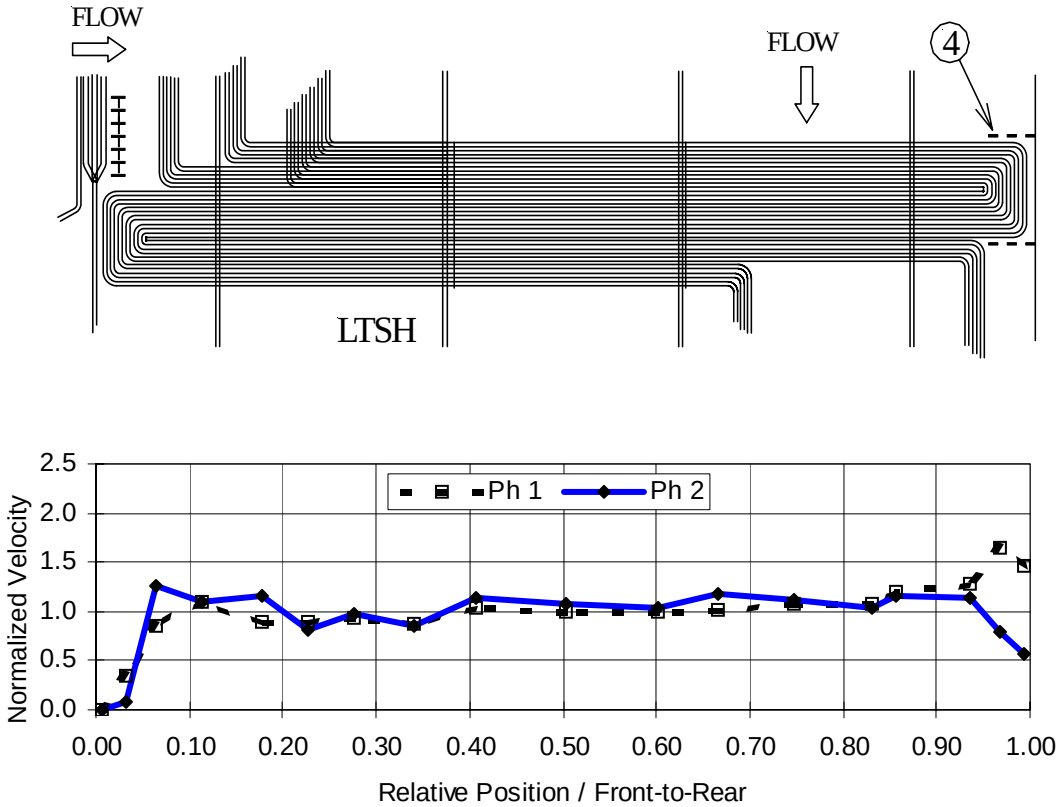

Figure 6. Normalized Velocity at LTSH Bank Inlet vs. Relative Distance Front-to-Rear

Upper Economizer Bank Inlet

Perforated plate baffles were installed above the LTSH Supply tubes and at the inlet to the upper economizer bank, Figure 7. These baffles would cover the rear section between the rear hanger tubes and rear wall and run from sidewall-to-sidewall.

The front-to-rear plot on Figure 7 shows velocities followed a similar pattern for the front half of the unit with many readings slightly higher that the original test. This may be due to the influence of the perforated plate baffles in the rear section where velocities have been reduced to more than 25 percent below plane average. This pattern suggests that flow may have redistributed over the entire plane due to the added resistance of the perforated plates in the rear. The large decrease in flow in the rear section was needed to provide long-term protection to an area that was severely eroded since commissioning.

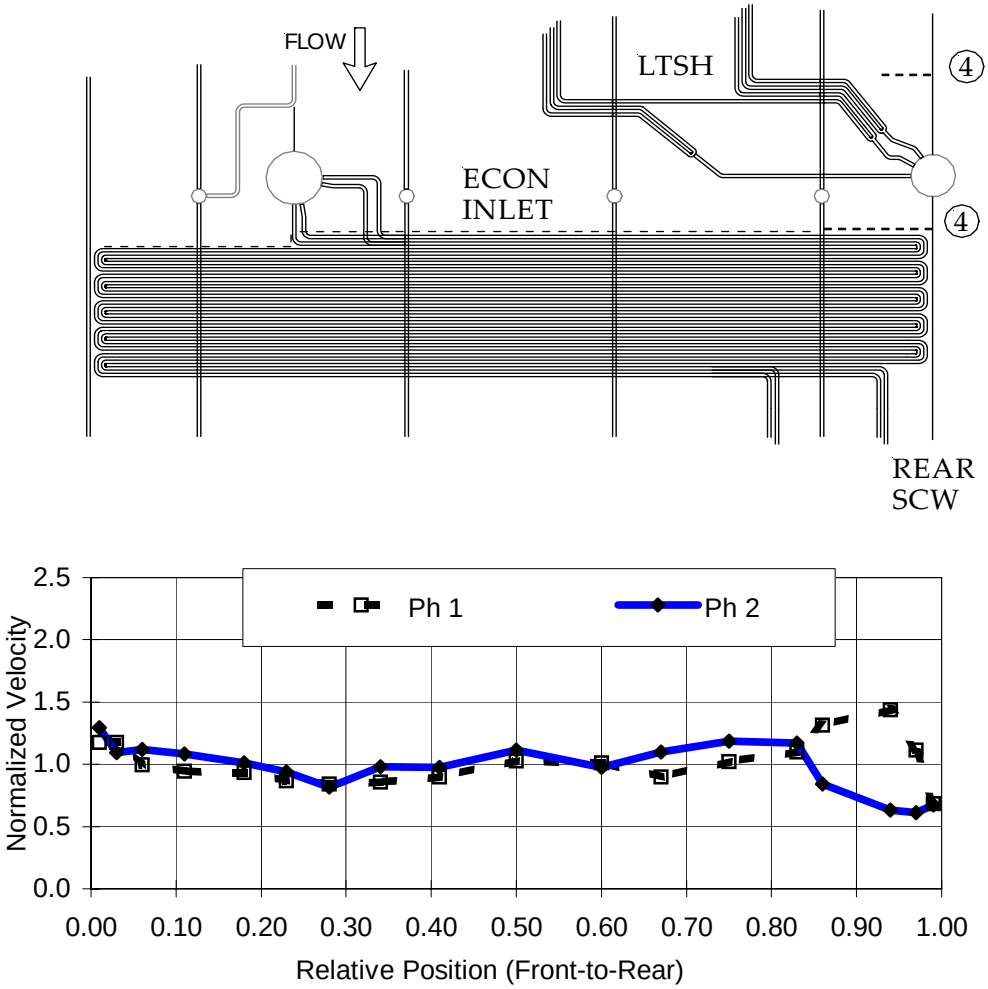

Figure 7. Normalized Velocity at Upper Economizer Bank Inlet vs. Relative Distance Front-to-Rear

Tube Shields at Hanger Tubes

Angle shields were recommended for horizontal banks near hanger tubes to reduce reported erosion of the bank tubes at those locations, Figure 8. The second and third sets of hanger tubes have been identified as the location of LTSH tube erosion, on the rear side of the hanger tubes. Solid shields would prevent direct impingement of gas/ash on the tubing from normal flow through the lanes and from sootblowing operations from above or below the bank.

Figure 8
LTSH Tube Shields at Hanger Tubes

Sidewall Gap Baffles

Isolating sidewall gaps such that flow along the sidewall is reduced can reduce erosion of bank tubing adjacent to the sidewalls and reduce bypass flow. This is especially useful where the sidewall gap is larger than the tube-to-tube spacing such as when one or more sidewall assemblies have been removed. Installing a skirt shield (solid panel) on the wall side of the first assembly from the sidewall and perforated plate baffle at the inlet to the gap effectively isolates the gap, Figure 9.

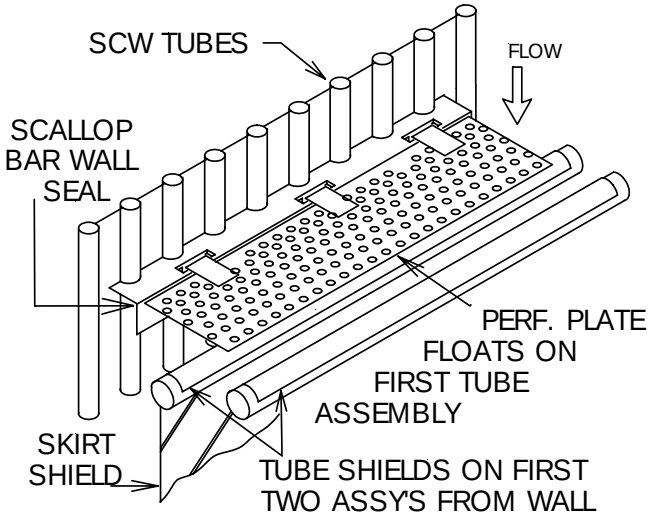

Figure 9
LTSH Tube Shields at Hanger Tubes

Summary

Prior to the CAVT methodology and associated use of flow control devices in the early 1980's, organizations relied on palliative approaches to prevent BTF's: solid baffles, shields, weld overlays, plasma sprays, etc., which did not address the cause of the problem and very often moved the problem to adjacent areas. The CAVT approach is a systematic method that identifies and eliminates causes of severe erosion conditions – maldistributed fly ash and local high velocity flow. Erosion history, unit design and operation and a CAVT data can be used to identify the type and placement of flow control devices that would redistribute fly ash and reduce local gas velocities. Lower flows can reduce peak erosion rates to 10-20 percent of the uncontrolled erosion rates and virtually eliminate the most serious erosion problems.

This technique has been used around the world in a multitude of boiler designs with different fuel sources. In today's competitive environment, this technique should also be used in a predictive manner; that is, new units should be tested and fitted with erosion controls to reduce and/or eliminate the likelihood of fly ash erosion BTF.

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5. "Guidelines for Control and Prevention of Fly Ash Erosion in Fossil Power Plants", EPRI TR-102432, 1994.

Circumferential Cracking in Chromized, Water-touched Tubes

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Abstract

In the past two years, PPL has experienced failures in chromized tubing installed as a preventative measure against excessive wastage in our supercritical boiler. One series of failures occurred in chromized tubes that were immediately adjacent to weld overlay, where circumferential cracks initiated at the toe of the overlay weld where it lay atop the chromizing. The cracks penetrated the chromized layer, following the chromium-rich grain boundaries until they reached the underlying T11 tubing. Once access to the underlying tube, the cracks propagated in a manner typical of circumferential cracking. The driving mechanism behind the initiation of these cracks appears to be the combination of residual stresses associated with the weld overlay and the thermal exposure from the overlay on the chromized layer, which produced an elevated precipitation of what appears to be sigma-phase (Cr-Fe) along the grain boundaries.

Introduction

Beginning in 1996, PPL embarked on a program of to protect the waterwalls and centerwalls of their supercritical boilers from excessive wastage that had accompanied the installation of low NOx technology. One of the materials used in this program was a chromized low alloy steel, where 1¼Cr-½Mo tube panels were taken and heated in a chromium-rich environment to create a thin (10-20 mils) chromium diffusion coating on the outer surface of the tube. The extent of this installation on the left side wall for one such unit is shown in Figure 1.

When that unit came down for its Spring 2002 scheduled overhaul, it was already leaking at a sidewall tube, in tube #238 (counting from the front wall) out of 280 tubes. The leaking tube was the end-most tube in a chromized panel that abutted up against a field-overlayed (625) panel installed in 1996. A close-up of the circumferential crack is shown in Figure 2a. The larger opening in the middle of the crack is due to steam/water cutting after the crack broke through-wall. In January, 2004, a additional sample was removed from the rear wall during an unrelated forced outage with the tube surface extensively cracked along much of the sample length (Figure 2b).

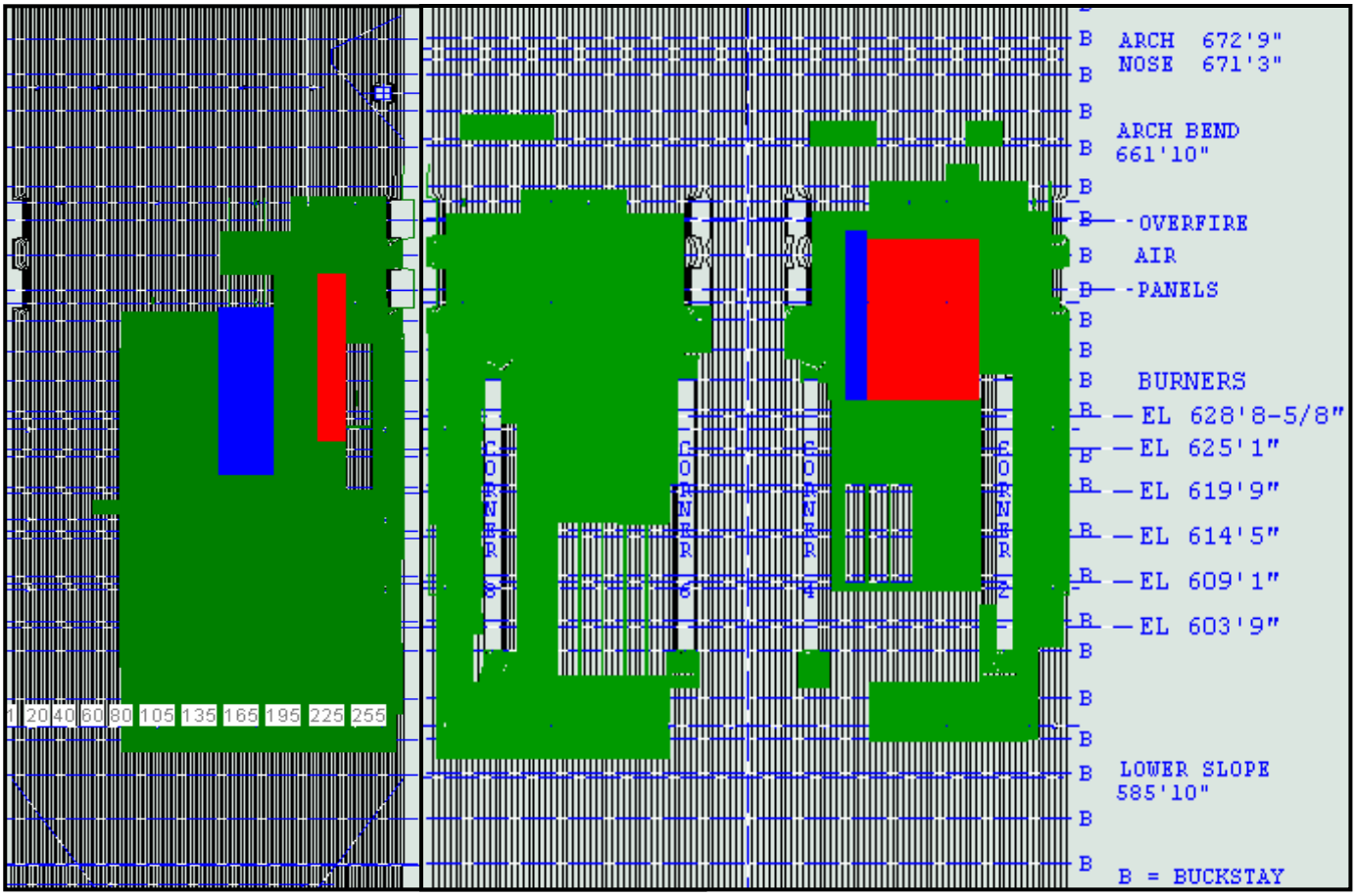
Investigation and Discussion

The cracking mechanism, once it penetrates the chromizing, is the same mechanism reported previously in unprotected Cr-Mo boiler tubing. Figure 3 shows an x-ray map of the circumferential cracking in the rear wall tube, after 7 years of service (1996-2003). The sulfur-rich spines in the oxide filled crack are typical of the mechanism.

This investigation is centered on how the chromized surface is penetrated in service. Figure 5 shows the surface of tube 238, immediately adjacent to the through-wall crack. The cracking in the outer surface of the chromized layer appears to follow the grain boundaries within the chromizing and, occasionally this intergranular attack will be found to extend to the underlying ferrite (Figure 6). A closer examination of this intergranular attack shows a higher chromium content at the grain boundary (Figure 7) and a predilection for cracking at the interface between this phase and the grain body (Figure 8). Cracking at this interface can also be accomplished by taking a microhardness indentation overlapping this phase (Figure 9), indicating a fairly brittle interface between the two phases.

A sample of new chromized tube was taken and subjected to an aggressive thermal cycling of 900°F (furnace, 1 hr hold time) followed by a water quench in room temperature water. This cycle was repeated ten times and the sample then sectioned metallographically. Figure 10 shows a comparison between before and after this rudimentary thermal treatment, which induced cracking associated with the brittle intergranular phase within the chromizing, similar to what is observed in in-service cracking shown in Figure 8.

The exact nature of the precipitate is not definite, but it appears to be related to σ-phase found in stainless steels (etching with 10% KOH brings out the precipitate, see Figure 11). Exposure of chromized tubing to temperatures in excess of 1000°F results in an increase in the amount of this precipitate and spot analysis shows roughly 50/50 Cr/Fe in the larger particles (see Figure 12) after service exposure.



LEFT WALL **REAR WALL**

Figure 1

Chromizing (red), shop overlay (blue) and field overlay (green) in Unit #2.

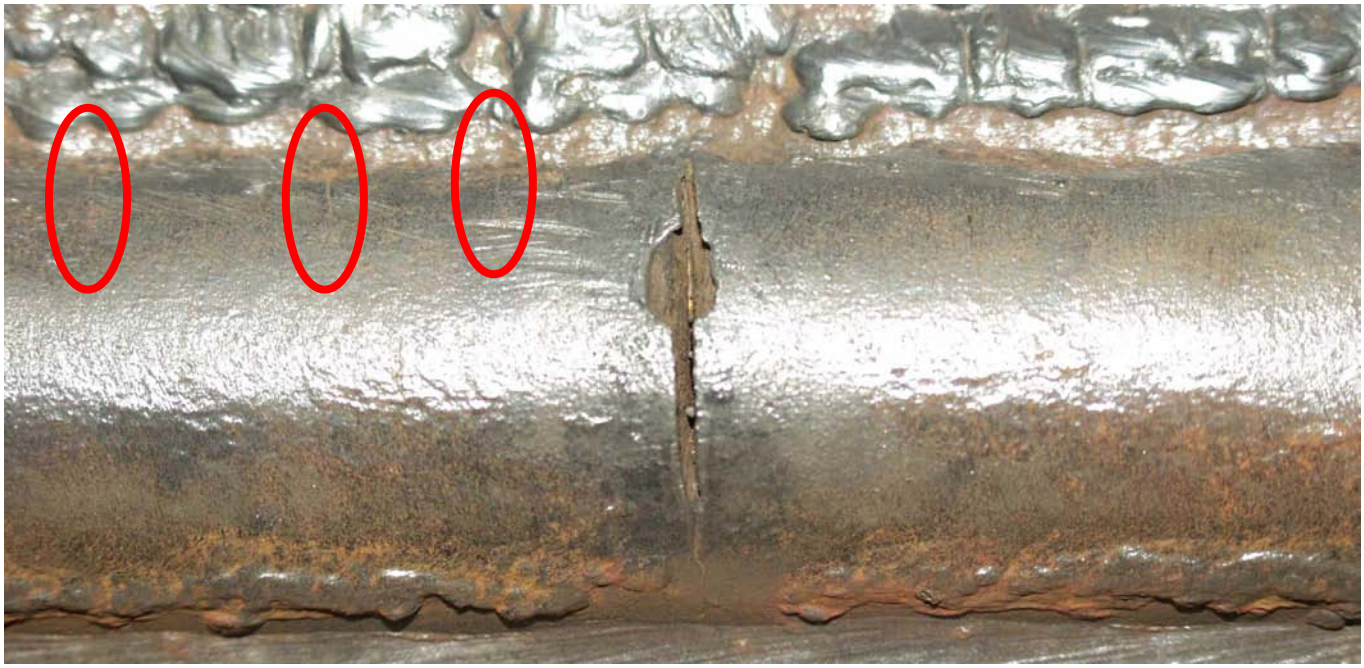


Figure 2

Above: Photograph of the leak in left side wall tube #238. Additional cracks are highlighted.
Below: Photograph of rear wall tube #451, showing extensive circumferential cracking.

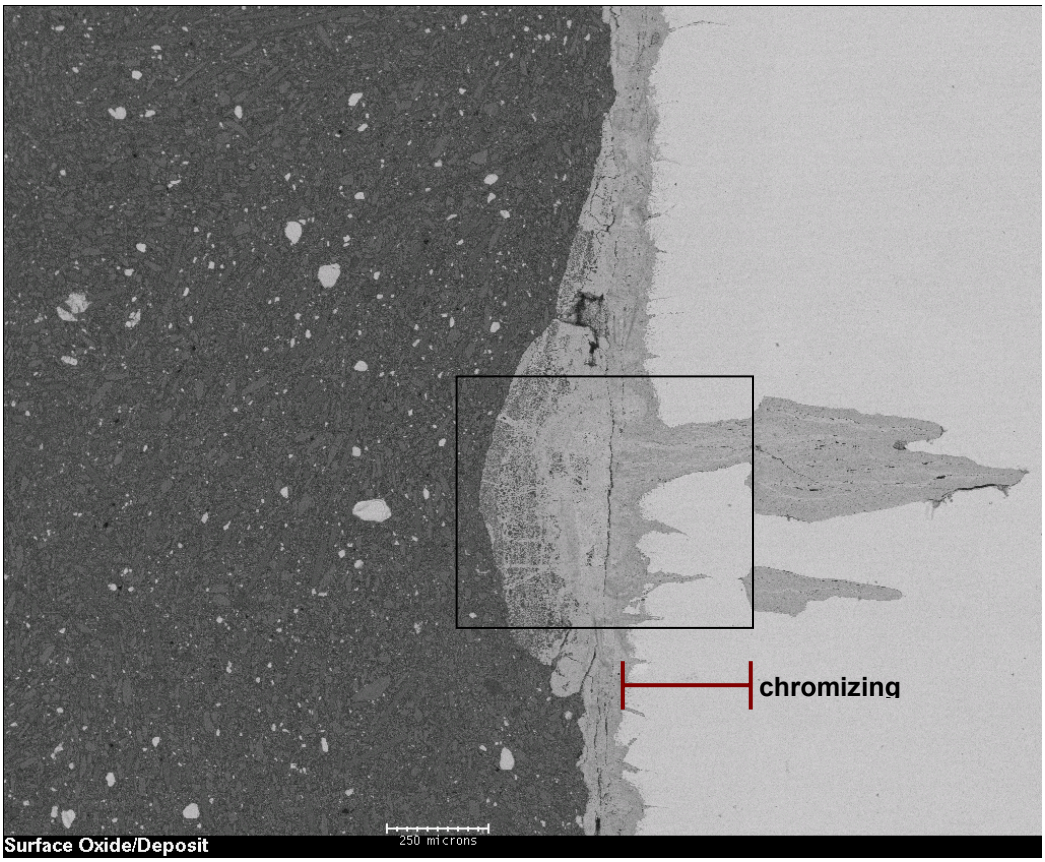
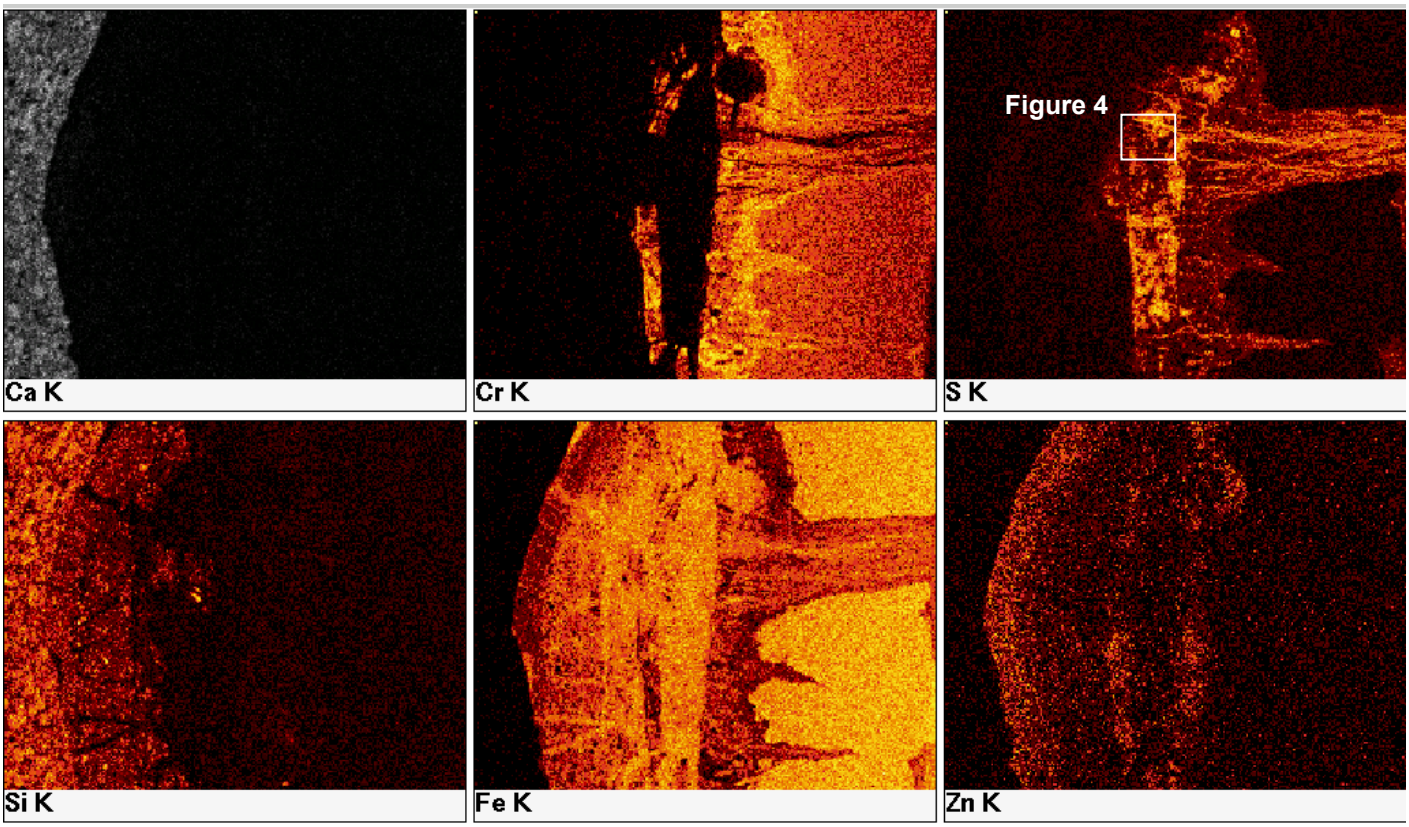


Figure 3

Above: Backscatter electron image of a cross-section through a circumferential crack in rear wall tube #451.
Below: SEM x-ray map through the surface deposit and crack through the chromizing.



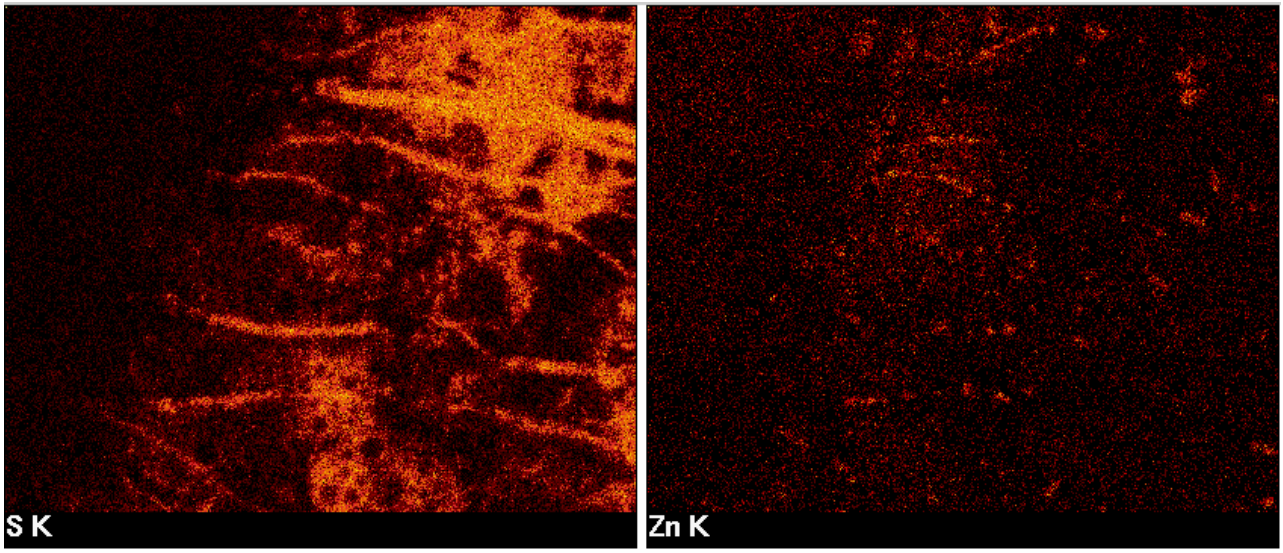
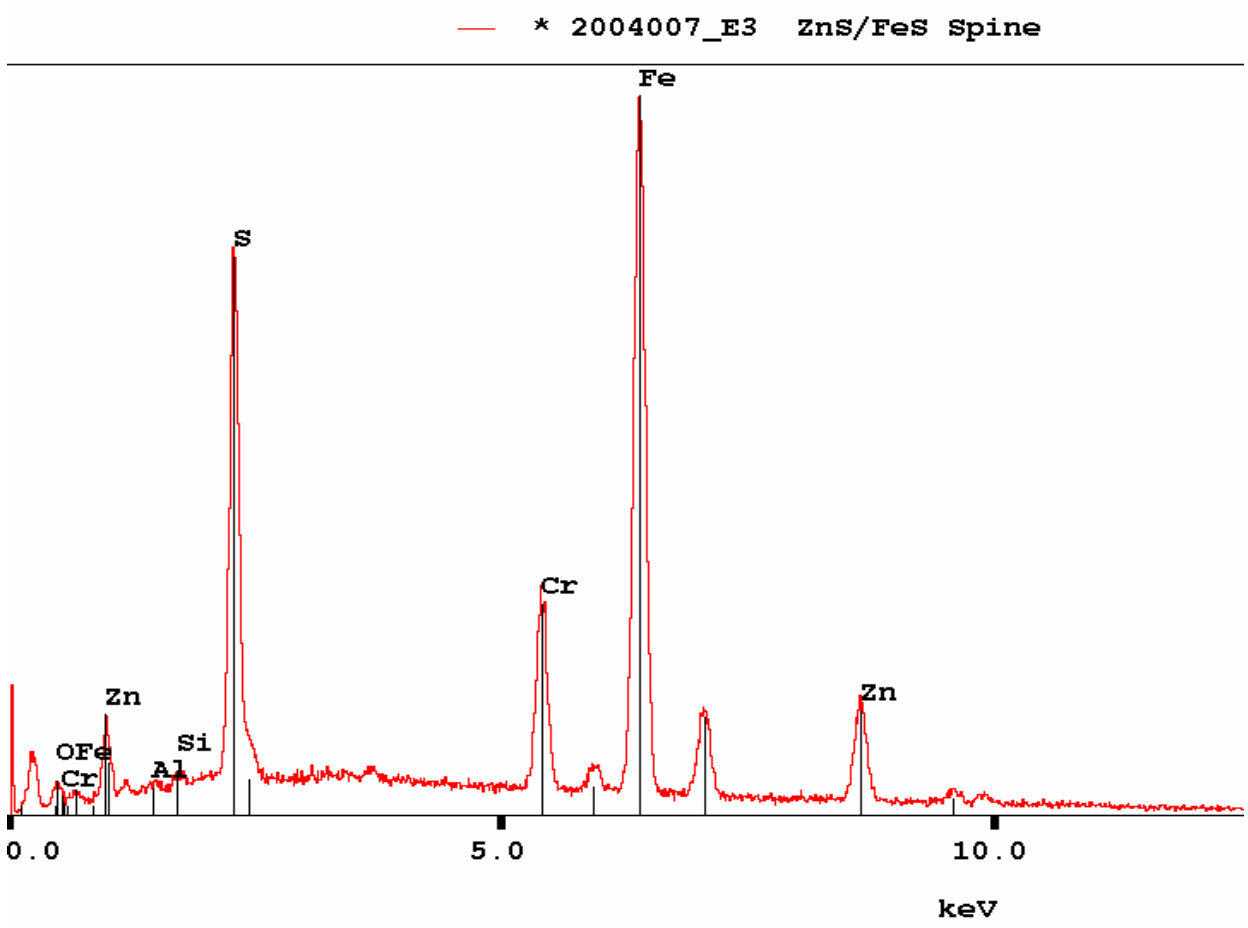


Figure 4

Higher magnification Zn & S x-ray map of the surface deposit (*above*) and EDS spectrum of sulfur-rich spine (*below*).



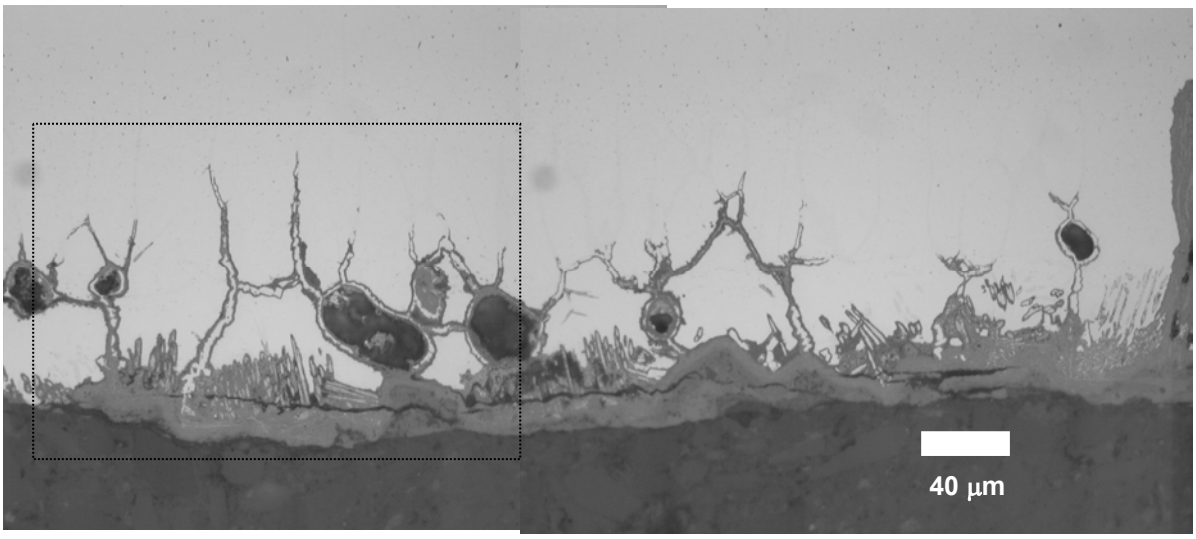
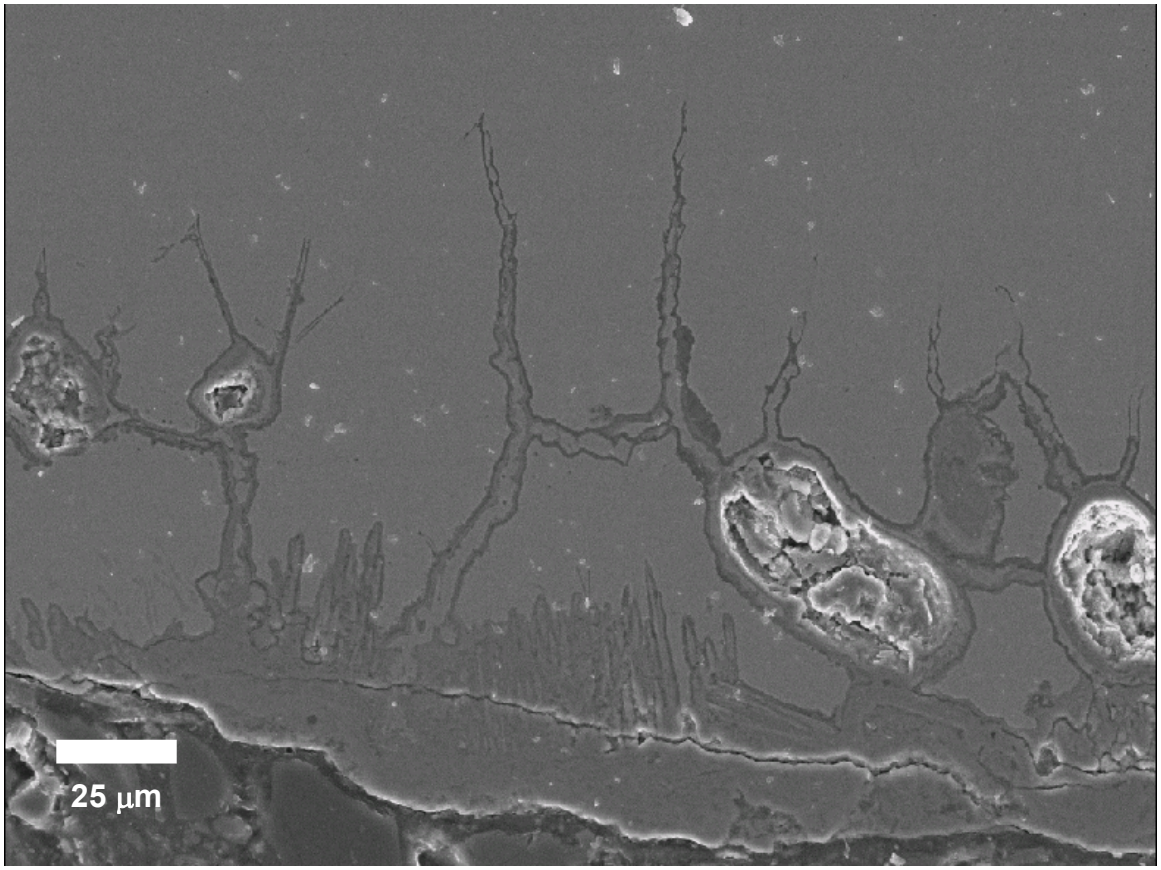


Figure 5

High magnification image of the surface of the tube immediately adjacent to the through-wall crack, showing the micro-cracking visible in the chromized layer. The same area is shown below in the electron microscope.



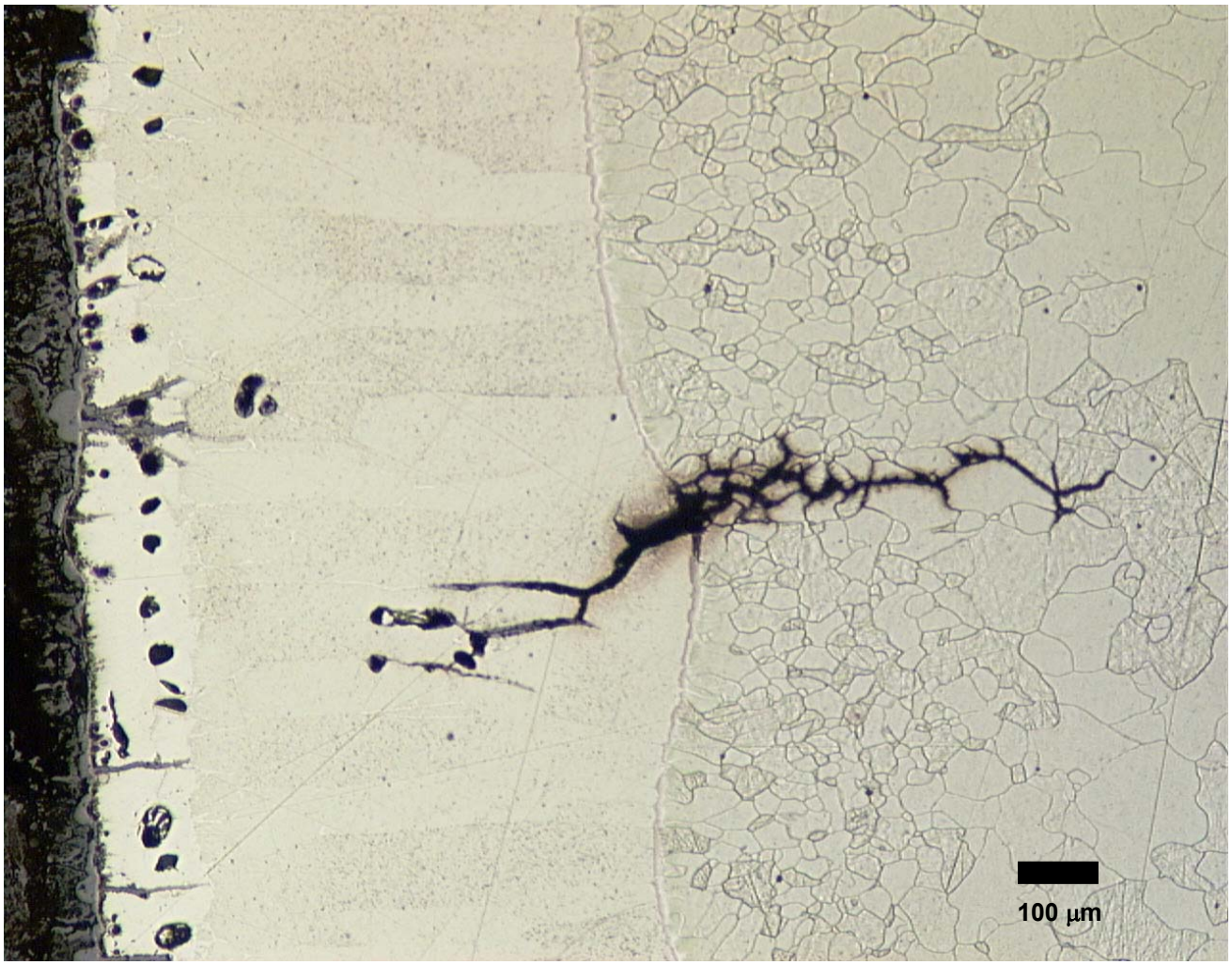


Figure 6

Intergranular attack in rear wall tube 451. The cracking in the columnar grains of the chromized layer extends to the surface out of the plane of this image. 5% Nital.

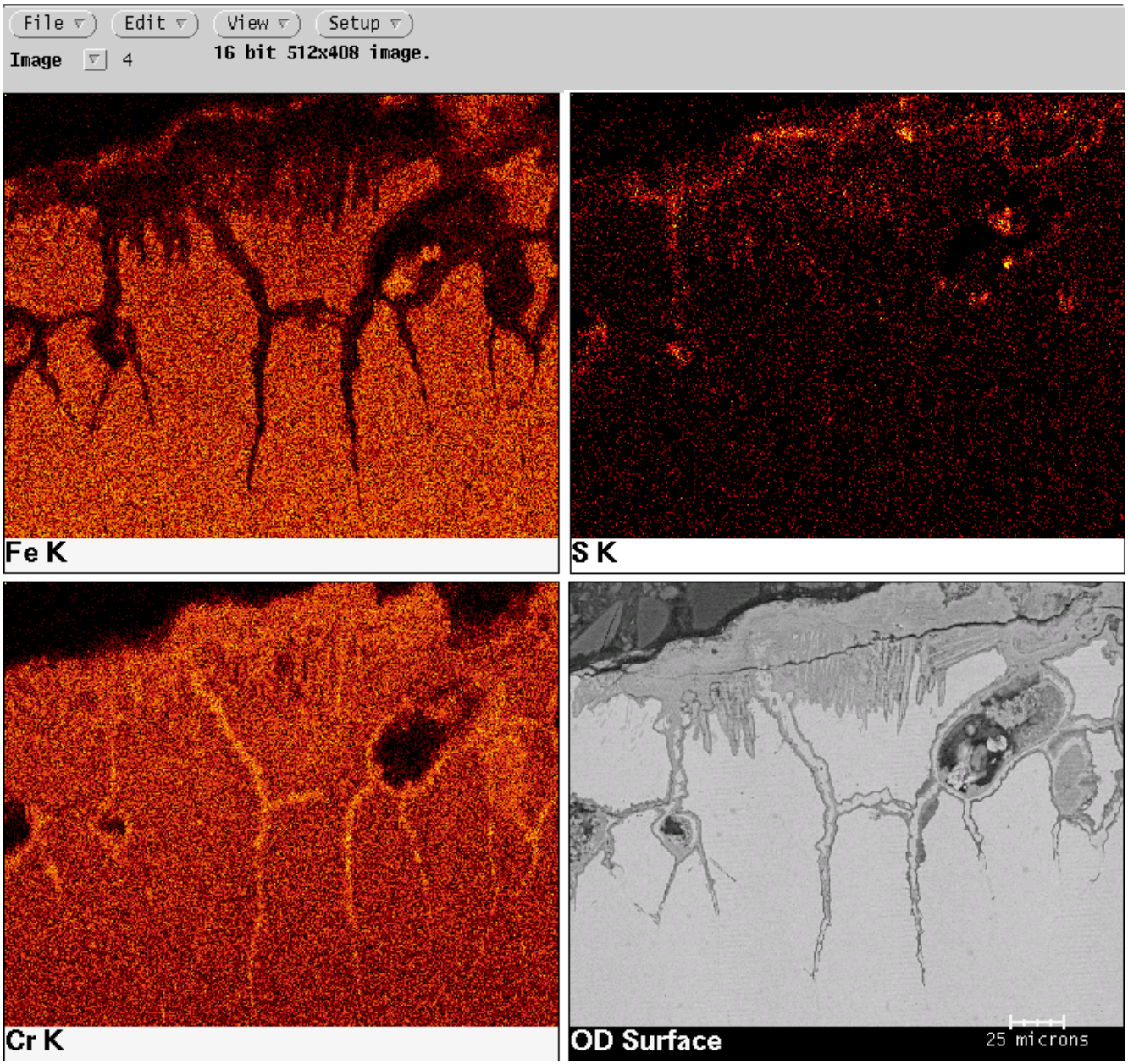


Figure 7

X-Ray maps of the area shown in Figure 4, showing a lower iron content, elevated sulfur and chromium in the corrosion/oxidation product. The image in the lower right is a backscatter electron image highlighting atomic number contrast.

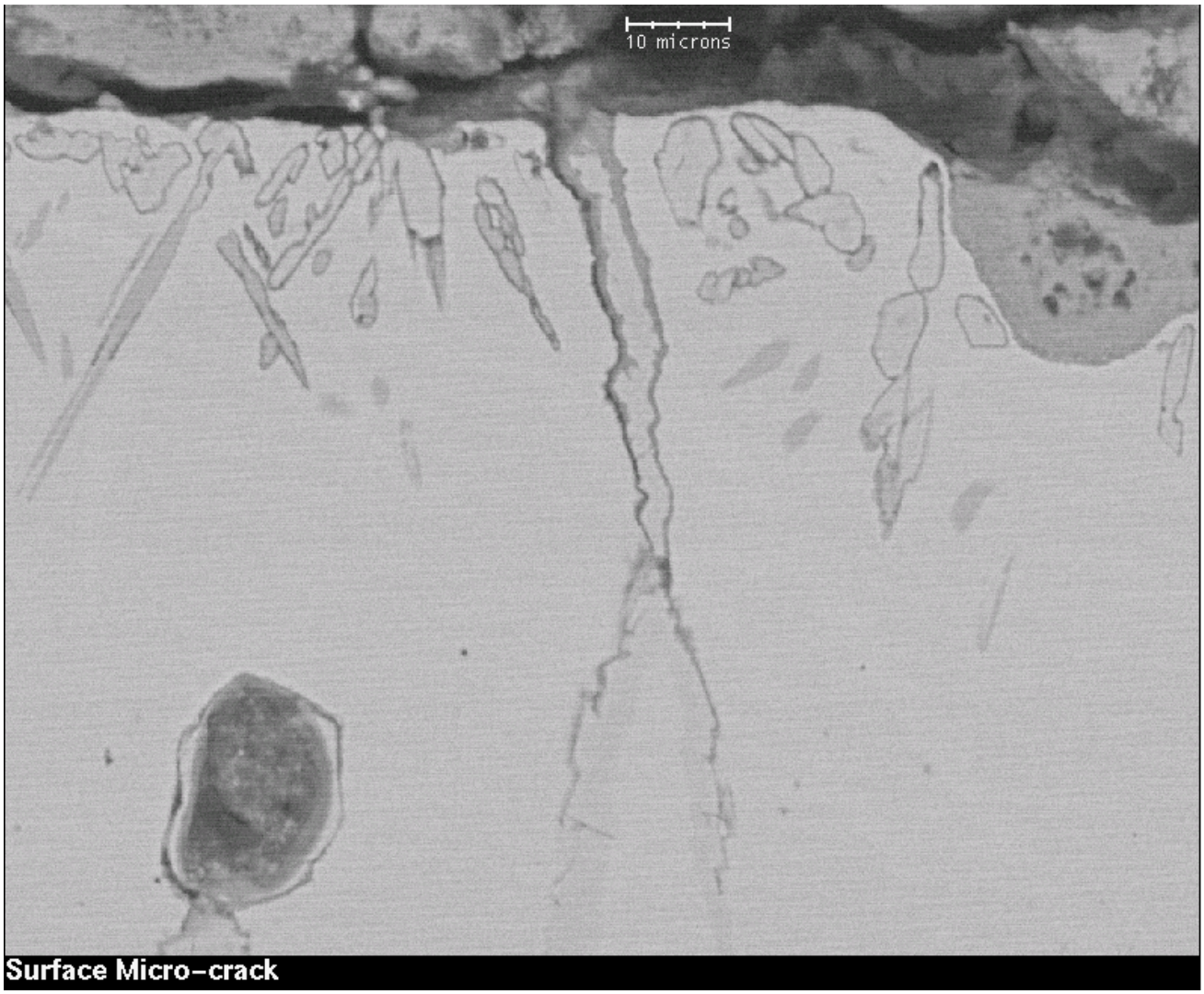


Figure 8

High magnification backscatter image of the surface showing what appears to be an initiated surface crack at the interface between the chromium diffusion layer and the chromium richer phase along the grain boundaries.

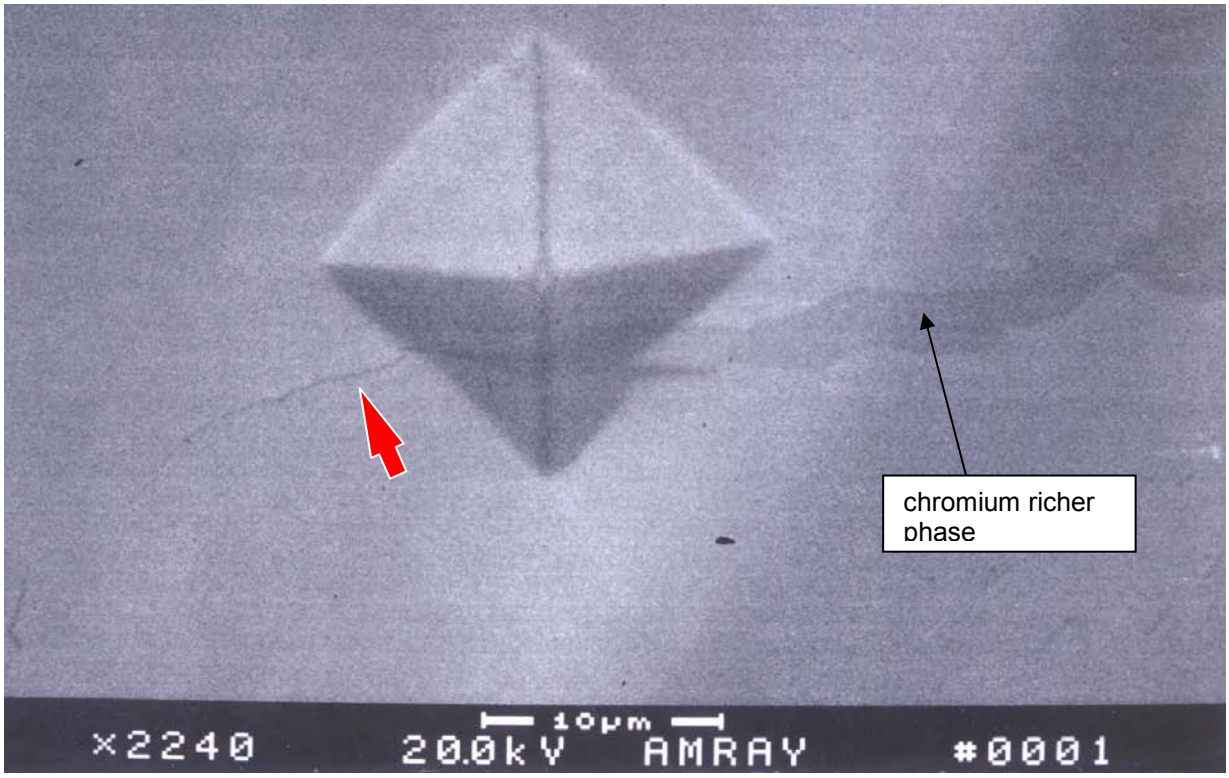


Figure 9

BSE images of microhardness indentations taken through the chromium-richer phase. A crack has formed at what looks to be the boundary of the phase (arrow), suggesting a brittle interface between the two regions.

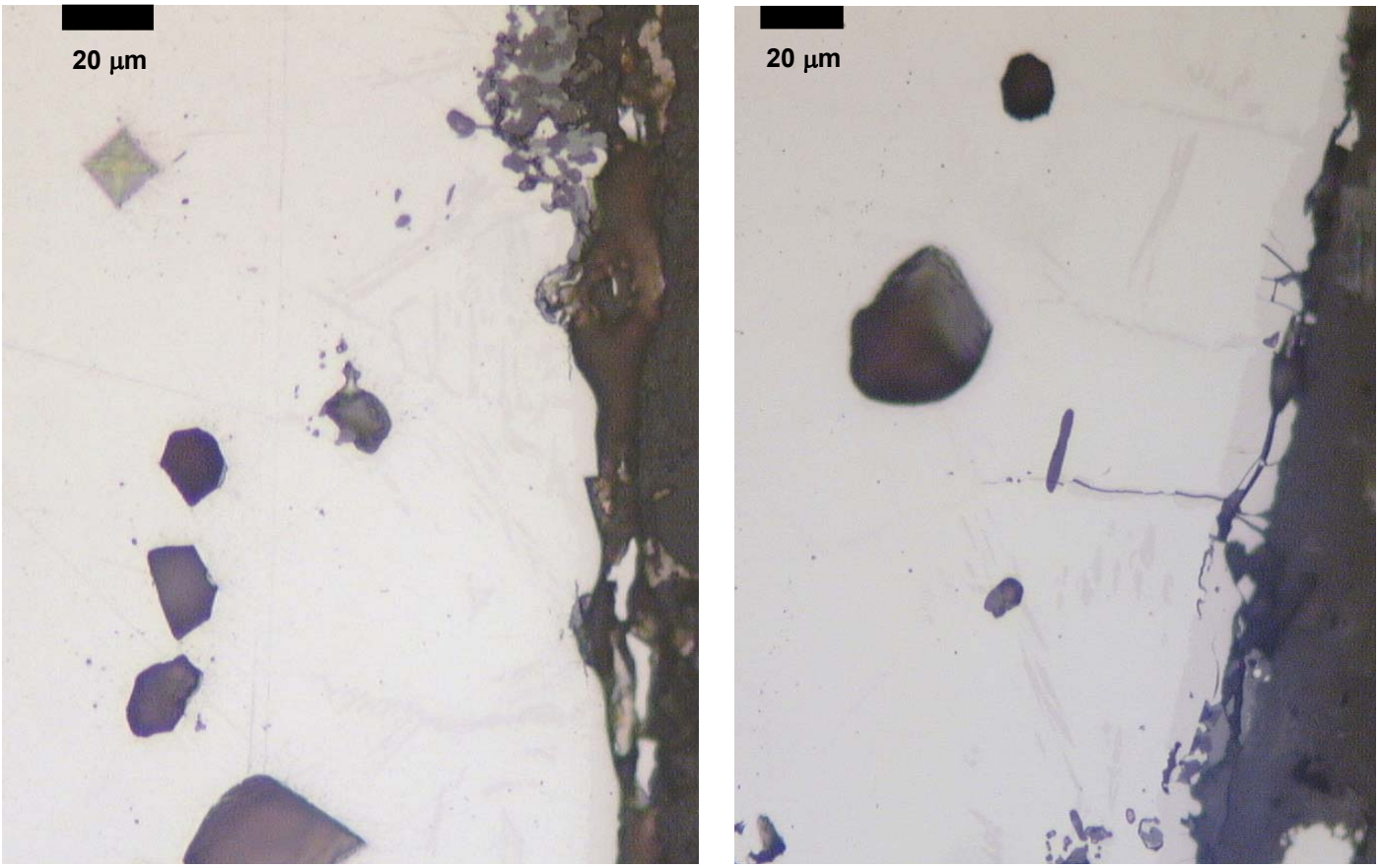


Figure 10

Light Optical images of the chromized surface of a new tube, before (*left*) and after (*right*) thermally cycling the sample between 900º and 70ºF (water quench). The chromium-richer phase faintly visible in these images as a slightly darker gray phase has developed cracks from the thermal cycling in the sample on the right.

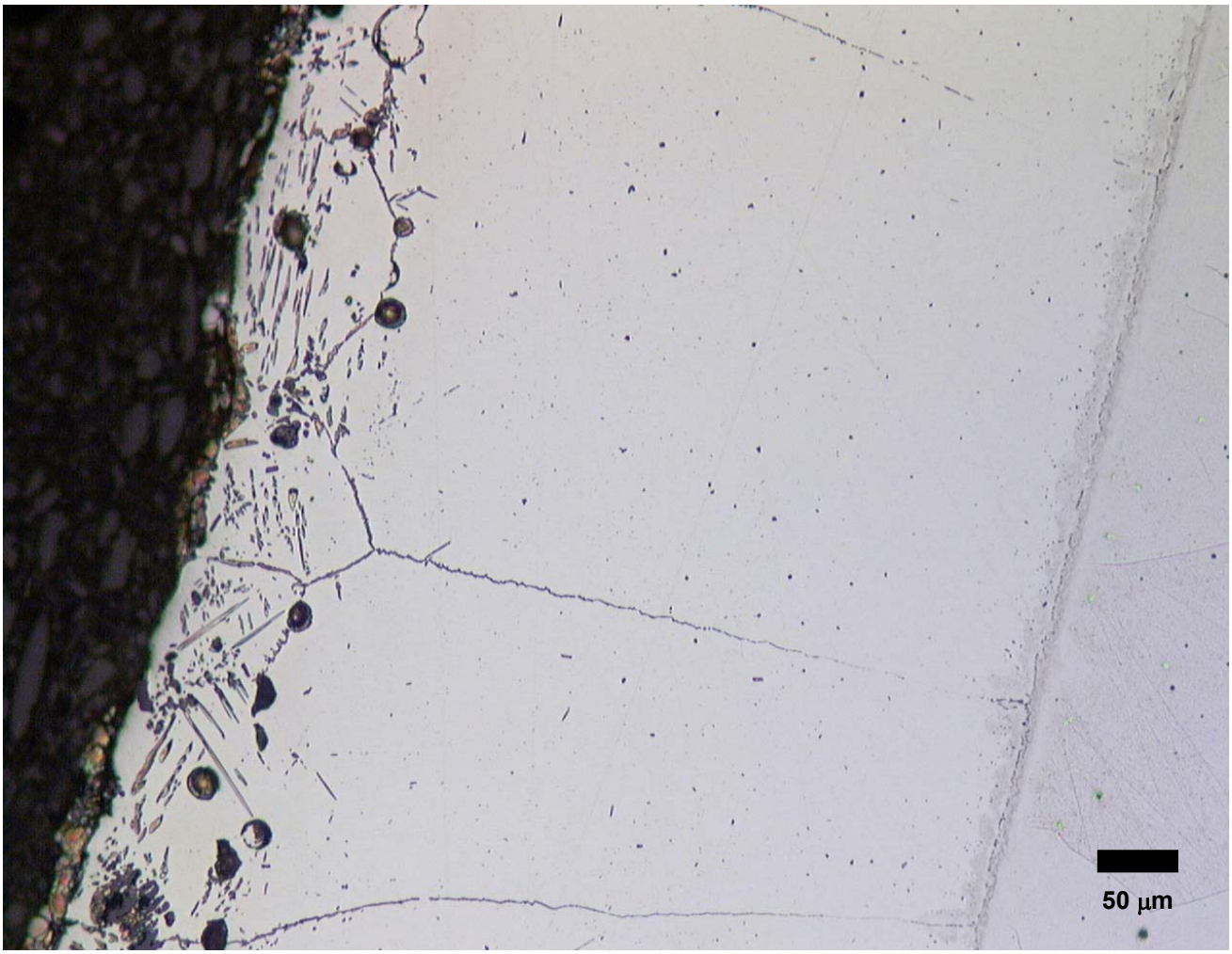


Figure 11

Sample of new chromized tube etched to reveal σ-phase.

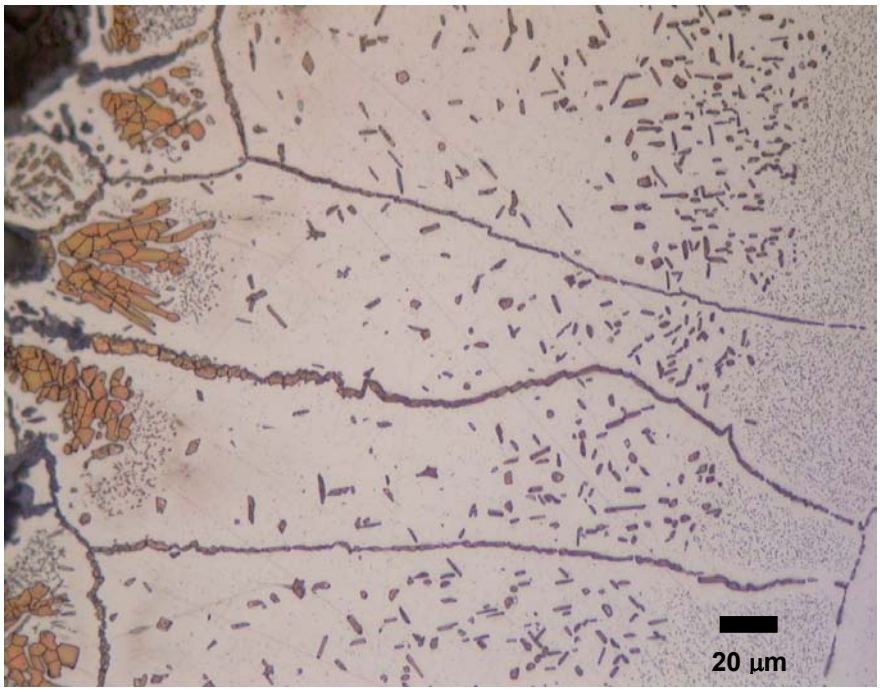
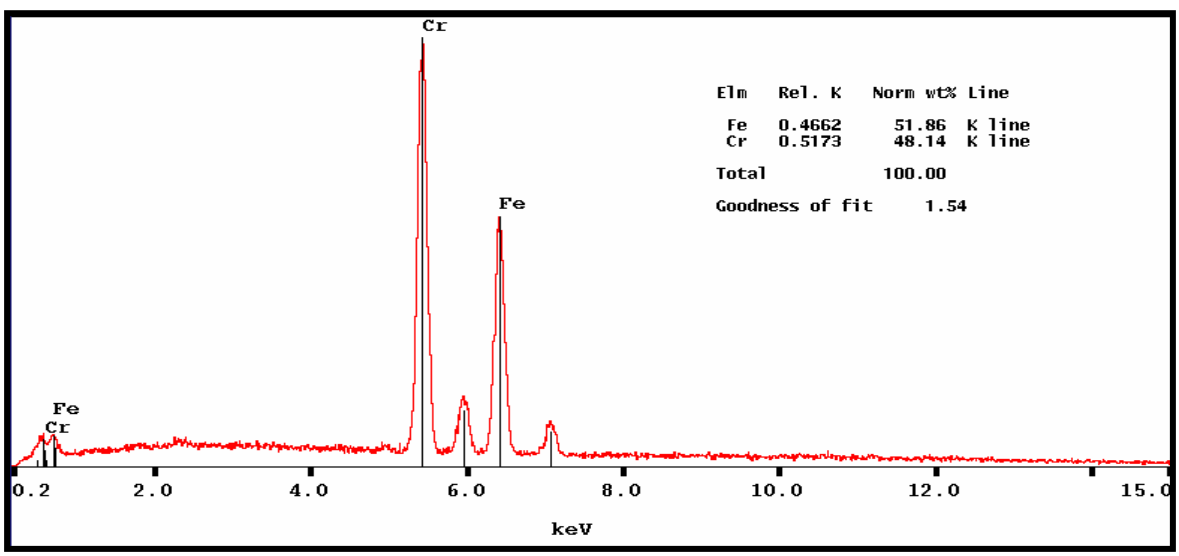


Figure 12

Above: Service exposed centerwall tube that failed due to creep after 3 years of service, etched for σ-phase.
Below: SEM/EDS spectrum of the intergranular precipitate, showing a 50/50 Cr/Fe composition.



SESSION 9: Mechanisms #4 – Stainless Steels

Chairman: P. James, EON-UK

The Importance of Solution Annealing Heat Treatment and Material Composition in the Performance of Austenitic Stainless Tubing Used in High Temperature Applications

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Abstract

Over the years, improvements to austenitic stainless steel materials have revolved, in part, around improving the material's resistance to corrosion. However, beginning in the late 1930's, it was discovered that the austenitic stainless materials could be modified to provide superior mechanical strength at high temperatures. While the utilization of austenitic grades such as TP-321H and TP-347H has been commonplace in the power generation industry for more than 50 years, a review of optimum processing requirements for these grades, as well as a consideration of the impact of certain aspects of material composition, may prove beneficial to anyone working to understand and to prevent component failures in austenitic stainless tubing. The purpose of this paper is to discuss certain aspects of the chemical composition and of the heat treatment of the high temperature austenitic stainless steels that are used to fabricate pressure parts for utility-type boilers. Several examples are presented to illustrate the consequences of failure to satisfy optimal compositional and processing requirements.

Introduction

The stainless steels designated as austenitic are classified by their crystallographic structure, which remains face centered cubic at room temperature. Elements such as nickel, carbon, and nitrogen stabilize this face-centered cubic, or austenitic phase, while ferrite forming elements, such as chromium and molybdenum, are critical to the material's corrosion resistance. Among other advantages, the fully austenitic alloys resist the embrittlement that inevitably occurs in ferritic stainless steels following prolonged operation at elevated temperatures. Typically, an austenitic stainless steel will be comprised of 16 to 26 weight % chromium and 8 to 24 weight % nickel. Under specific conditions, the chromium-rich oxide layer that forms on this steel is continuous, non-porous, and self-healing if disrupted in the presence of oxygen, and this oxide layer offers superior resistance to certain corrosive environments.

Fairly early in the application of the austenitic stainless steels it was recognized that their ability to resist corrosion at lower temperatures could be compromised when, during any phase of processing or operation, they were exposed to temperatures between approximately 800-1600° F. At these temperatures, chromium-rich carbides can precipitate at grain boundaries, which precipitation reduces the chromium content in the region immediately adjoining the grain boundary. As a result, under many conditions of exposure, the chromium-depleted region will

act as the anode in an electrochemical cell and preferential attack along the grain boundaries, termed intergranular attack (IGA), will occur. To counteract this problem, several modifications were introduced to the original compositional formulations, including a reduction in the carbon level (e.g., the type 304L grade) and the addition of elements having a higher affinity for carbon than chromium (e.g., columbium in type 347 and titanium in type 321). Thus, types 347 and 321 originally were developed, in large part, for their improved resistance to IGA. However, early testing on the modified compositions with columbium and titanium additions revealed that these grades could be optimized to provide substantially better creep rupture strength than the standard 18-8 grades. The ASME requirements that currently exist for the H grades of austenitic stainless steel (i.e. TP-347H and TP-321H) reflect the minimum changes in composition and processing that were found to be necessary to obtain good elevated temperature strength.

It is important to note that in optimizing the resistance of the modified austenitic grades to creep deformation by adding titanium or columbium it was recognized by the alloy developers that the addition of these elements would not confer immunity to IGA for material operating for long periods of time at elevated temperatures. However, for many high temperature applications, including large utility-type boilers, this was not regarded as a significant liability. In fact, it is not uncommon to observe shallow intergranular attack in boiler tubing manufactured from one of the austenitic H grades that has operated at elevated temperatures for an extended period of time. This occurs because during the life of the tubing the material inevitably passes through a period during which it becomes sensitized and, so long as the tubing is not subjected to aggressive contaminants while the boiler is off-line during that period, the sensitization does not compromise serviceability. The sensitization of the columbium and titanium alloyed grades occurs more slowly than it does for TP304H, for example, and several years of operation may be required to achieve the maximum level of sensitization for a specific heat of 347H or 321H tubing. It also is important to note that with continued elevated temperature operation the degree of sensitization for all grades gradually diminishes, because the material "heals" as the chromium slowly re-diffuses into the depleted grain boundary region at elevated service temperatures.

It should be emphasized, however, that a number of boiler operators have experienced failures due to intergranular corrosion of TP347H or TP321H tubing as a result of exposure of the material to contaminated condensate in areas, such as the lower bends of pendant elements, where the condensate collects when the unit is off-line. A possible countermeasure for this type of damage would be the use of a modified alloy, such as UNS34751 or the new TP347W, in which the carbon is maintained at low levels ($\leq 0.02\%$) and the columbium at high levels to substantially increase resistance to sensitization, even after prolonged operation at elevated temperatures.

The Effect of Chemical Composition

When austenitic stainless steels are alloyed with carbide/carbonitride forming elements, the result can be increased resistance to IGA, as previously discussed, and improved creep strength. The latter is the focus of the remaining discussion. By accepted definition, creep is the time-dependant and permanent deformation that occurs under stress at "elevated" temperatures (i.e., elevated relative to the melting temperature of the material). The propensity for forming creep damage increases with increasing stress and temperature. At temperatures above approximately

900° F for the ferrous alloys, diffusion-based creep becomes a concern for boiler components. The grades TP-347H and TP-321H exhibit a superior resistance to creep rupture at the higher temperatures encountered in superheater and reheater service due to the fact that fine particle (secondary) carbonitrides (i.e. CbC, TiC, etc.) precipitate during creep deformation. These precipitates tend to form at dislocations, so that the dislocations are "pinned", thereby resisting dislocation movement and reducing creep deformation.

Obviously, to the extent that this model of the alloy strengthening mechanism is correct, anything that optimizes the number of carbonitride precipitates will optimize the creep rupture strength of the steel. Research has shown that, as long as the solubility limit is not exceeded, the more carbide/nitride forming elements (i.e. Ti, Cb, V, etc.) that are present the higher the creep rupture strength. However, if the solubility limit is exceeded, the creep rupture strength can be reduced.

Several researchers have studied the effect of varying the ratio of these alloys with respect to the amount of carbon in the material. In the work of Kikuchi et al.[2], and the work of Keown and Pickering [3], the effect of varying the Cb:C ratio in austenitic stainless steel was studied. Based on this research, it was established that the optimum creep-rupture properties were achieved when Cb and carbon were added in a proportion approximately equal to their stoichiometric ratio. There is some disagreement among researchers as to whether the composition of the precipitate that forms approximates Cb_4C_3 (Keown and Pickering [3]) or CbC (Kikuchi et al.[2]), but the majority opinion supports the composition CbC (Wadsworth et al. [4]). As shown below, the stoichiometric ratio of Cb:C in CbC is 7.735. Therefore, adding Cb and Carbon in a ratio approximately equal to 7.735 should optimize the creep rupture properties of the steel.

$$\text{CbC: stoichiometric ratio} = \frac{\text{Atomic weight Cb}}{\text{(n) Atomic weight C}} = \frac{[92.90638]}{[(1)\times(12.0107)]} = 7.735$$

More importantly, adding carbon and columbium in a ratio that is significantly different from 7.735 can result in a lowering of the creep rupture strength, with the reduction in strength being directly proportional to the degree of deviation, in either direction, from the stoichiometric ratio. Similar results were obtained when researchers studied the grade TP321H, in which the carbonitride precipitate assumes the composition TiC (stoichiometric ratio = 3.99). It is of interest to note that the ASME specifications that govern the chemical composition of the H grades of TP347 and TP321 mandate a specific level of either Cb (TP-347H) or Ti (TP-321H) based on the amount of carbon present. The levels defined in these specifications were derived from empirical data collected long before the precise stoichiometric ratios had been identified by laboratory research.

Another important consideration for optimizing the elevated temperature strength of the austenitic stainless grades is the level of nitrogen. Around 1950, it was discovered that there had been an unexplained improvement in the creep rupture properties of Type 304 austenitic stainless steel. Because specific changes in steel melting practices had coincided with the timing of this improvement, it was suspected that non-specified elements introduced during the melting process were the explanation for the improved performance of the steel. Goodell et al. [5] performed a series of tests in order to confirm this theory. Based on their research, it was found that the most significant non-specified element affecting the creep rupture strength was nitrogen. Higher levels

of nitrogen result in a greater number of carbonitride precipitates and this results in improved creep rupture strength. Over the years, a rule of thumb born out of experience provides that for SH and RH service in utility type boilers a minimum [carbon + nitrogen] content of approximately 0.12 weight % is beneficial for insuring that sufficient precipitates form to provide adequate elevated temperature strength. For various reasons, requirements to insure proper levels of nitrogen never were incorporated into the ASTM/ASME specifications at the time the defining research was conducted. Today, because of the loss of so many experienced materials specialists from the industry, the benefit of the nitrogen content to the creep rupture strength of these grades often is overlooked by many steel makers. As a result, in the last 15-20 years there have been an increasing number of heats of austenitic stainless steel tubing produced that comply with the ASME specification for SA-213, TP347H or SA-213, TP321H tubing material, but that do not meet this recommended level of carbon + nitrogen. Such heats could be comparatively "weak" and could fail prematurely if the component is designed to take full advantage of the material's strength.

The Need for Proper Solution Anneal Heat Treatment

In order to insure optimum creep strength of the H grades of austenitic stainless steels, a proper solution annealing heat treatment must be employed. The combination of time and temperature must be selected to dissolve a sufficient amount of the carbide and carbonitride forming elements to insure their availability for re-precipitation during service, recognizing that columbium and titanium are refractory elements that resist dissolution. When the solution annealing is properly performed, these elements then are available during subsequent service to form new carbides and carbo-nitrides, thereby pinning dislocations and improving creep strength. If, however, the elements are not dissolved in sufficient quantity during the solution annealing treatment, they will not be available for precipitation during service. Older revisions of the ASME SA-213 specification required a minimum solution annealing temperature (e.g., ref: ASME SA-213, 1992, paragraph 6.4). For example, the minimum temperature for TP347H was specified to be 2000°F. For some, but not all, heats of this material, a temperature of 2000° F for a short holding time is sufficient. However, there is ample evidence to indicate that for certain heats of material it is necessary for the solution annealing temperature to be significantly higher than 2000° F or the holding time significantly longer than 15 minutes. Therefore, the older revisions of the ASME requirement were not adequate for ensuring that the optimum heat treatment had been employed. The current revision of the specification attempts to address the limitations of its predecessor by requiring, in addition to the minimum solution annealing temperature, a grain size of 7 or coarser.

The issue of grain size is of interest, because it is commonly understood that, since the rate of diffusion-based creep is inversely proportional to the grain size, the implementation of a grain size requirement was dictated by the desire to minimize grain boundary area as a way of increasing creep strength. Obviously, in coarser grained material the grain boundary area is reduced, and this should result in a somewhat lower rate of accumulation of creep-related damage at a given set of operating conditions. However, this relationship is not the primary basis for the grain size requirement. Instead, the grain size requirement was based on empirical data that suggested a relationship between grain size and the dissolution of the critical

precipitate-forming elements. In other words, when sufficient dissolution of elements such as columbium or titanium is achieved through the solution annealing, thereby insuring satisfactory creep rupture strength, the grains will coarsen, resulting in an ASTM grain size of 7 or coarser. Therefore, the primary objective for implementing the grain size requirement was to insure that the heat treatment was adequate. It is important to note, however, that the correlation between grain size and dissolution of carbide and carbo-nitride forming elements is inexact, and can vary significantly from heat to heat of material. The grain size can be strongly influenced by the presence of refractory type non-metallic inclusions that effectively restrain grain growth, so that for some heats of material it is very difficult to achieve a coarse grain size, regardless of the degree of dissolution of columbium or titanium.

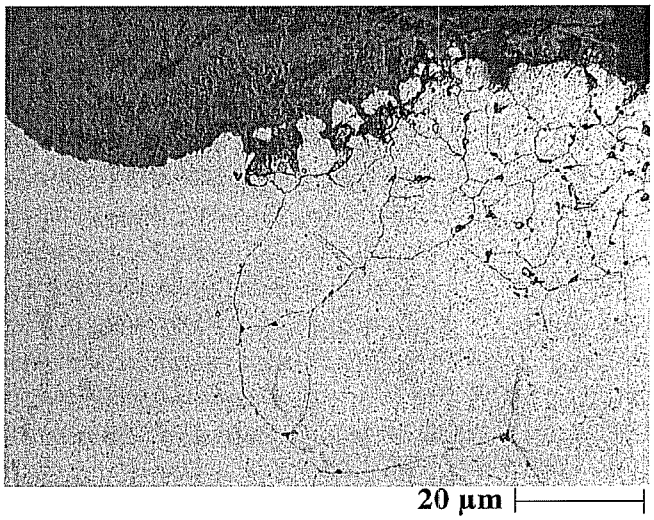
Recently, a number of austenitic tubes that were manufactured prior to the implementation of the grain size requirement were evaluated following a prolonged period of operation. The material in question was relatively fine-grained, with an average grain size finer than ASTM 7. Although the manufacturers may have complied with the minimum solution annealing temperature requirement that was in place at the time, these particular heats of material may have required higher solution annealing temperatures in order to optimize the creep rupture strength. As discussed in more detail below, these heats also contained levels of carbon + nitrogen that were below the 0.12% level. The combination of the non-optimum heat treatment and the less than desirable carbon + nitrogen content left these heats of material in a "creep weak" condition that resulted in premature failure of the tubing. These examples also demonstrate how this condition can be misinterpreted as long-term overheating damage.

Consequences of Not Optimizing for Creep Rupture Strength

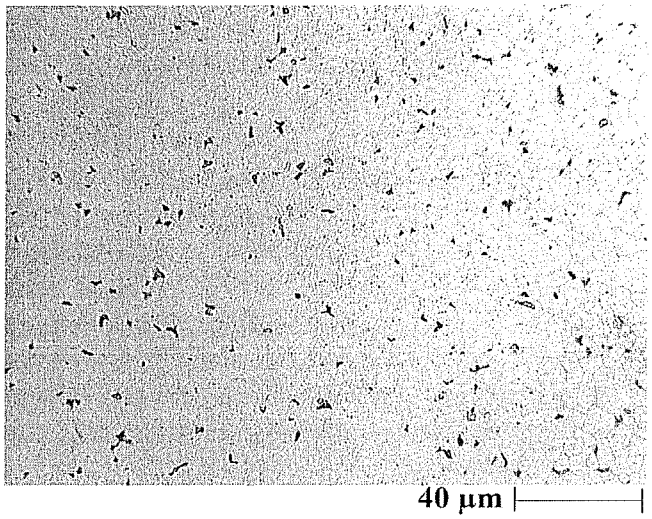
In 2003, seven sections of final superheater tubing were received for destructive evaluation. The samples were removed from a coal-fired boiler rated for a steam production of 6,351,470 lbs./hr (MCR), and designed to operate at a steam outlet temperature of 1000°F and a SH outlet pressure of 3625 psi. The samples were removed from tubing that was specified to be 1.50" OD x 0.220" MWT, SA-213, TP-347H material. The final superheater assemblies in this boiler had been replaced in 1993 and, less than 10 years later, 3 failures had occurred. At the time of the failures (2002), the failed tube sections were sent to an independent investigator for analysis so that the mode of failure could be identified. The independent analysis discovered creep damage in the failed tubes and reported that the failures were due to both short-term and long-term overheating.

Obviously, the customer's primary concern regarding the tubes submitted to the MTC was to determine if the unfailed tubing had suffered similar damage. As described below, the results of the MTC analysis confirmed the presence of creep damage, but indicated that the damage was not due to overheating. Instead, the damage was related to the non-optimal processing of the tubing prior to its installation. Had the tubing been processed in a manner that satisfied the criteria discussed above, it likely would have provided many years of additional service. Because the cause of the creep damage was misinterpreted, the plant reacted to what they thought was an overheating problem related to the operation of the boiler, when in fact the problem was caused by the as-installed condition of the tubing.

The metallurgical examination uncovered evidence of creep-induced cavitation at triple points and along grain boundaries. The micrographs presented below document the typical features that were observed in the damaged tubing. Despite the presence of significant amounts of creep damage, there was no evidence of prolonged operation at elevated temperatures, such as heavy precipitation of carbides along grain and twin boundaries or the presence of the intermetallic sigma phase.



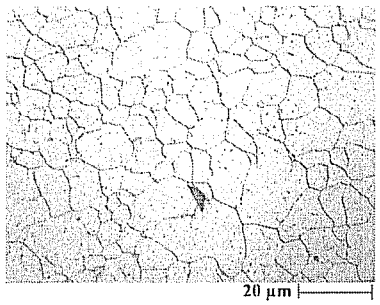
03145-W *Sample 6* Nitric Etch



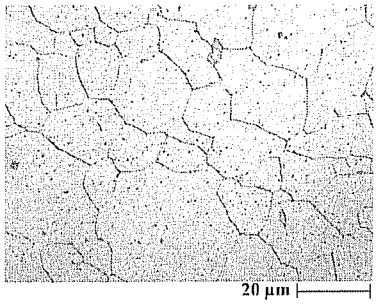
03145-AA *Sample 10* Nitric Etch

In attempting to understand how there could be creep damage in the absence of any clear evidence of prolonged exposure to excessive temperatures, several important observations were made. First, the chemical analysis of the TP347H tubing revealed that the nitrogen content was unusually low, so that the sum of the carbon plus nitrogen for this tubing was well below the 0.12% minimum considered essential. In addition, measurements indicated that the grain size ranged from 9.5 to 11.5. The very fine grain size suggested that the solution annealing heat treatment may have been inadequate.

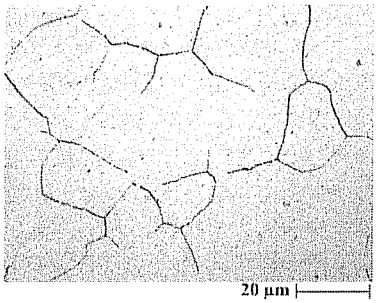
In order to estimate at what heat treatment temperature the grains for this heat of material would have coarsened, three sections were removed from one of the tubes and heat treated at temperatures of 2000°F, 2100°F, and 2200°F, respectively, for 15 minutes. The series of micrographs presented on the following page illustrates the grain size following each heat treatment. As shown, there was no significant change in grain size for the sample heat treated to a minimum temperature of 2000°F, suggesting that the original solution annealing temperature may have been as high as 2000°F, as was required by the ASME specification. The sample heat treated at 2200°F was the only sample that approached a grain size that would be acceptable by the current ASTM standard. The grain size shown for this sample was approximately 7.5.



2000°F Grain Size 11



2100°F Grain Size 9.5



2200°F Grain Size 7.5

The simple heat treatment study indicated that the material might not have been heat treated to a sufficiently high temperature to achieve optimum high-temperature rupture strength. In order for the tubing to have achieved satisfactory rupture properties, a higher solution annealing temperature, perhaps approaching 2200°F, for a sufficient length of time likely would have been necessary to allow adequate re-solution of critical carbonitride forming elements. A higher solution annealing temperature almost certainly would have increased the serviceable life of the austenitic tubing well beyond 10 years. Based on the results of this analysis, it was established that the creep damage formed at "normal" operating temperatures because both the heat treatment and the chemical composition of the tubing were not adequate to insure an acceptable level of elevated temperature strength.

Shortly after this analysis, a section of failed superheater tubing was analyzed that had been removed from a subcritical boiler that had been in operation for 50 years. The unit was rated to produce steam at a rate of 950,000 lbs./hr (MCR) with a superheater outlet pressure of 1500 psig and an outlet steam temperature of 1000°F. The tubing from which the sample was removed was specified to be 2.0" OD x 0.280" MWT, SA-213, TP321H material. The sample, shown in Figure 1 as it appeared when received from the field, contained a thick-lipped, fish-mouth type rupture along the "hot" side of the tube.

Longitudinal grooving was observed on both the OD and ID surfaces of the sample in the failure area, reflecting incremental creep swelling over a prolonged period of operation. Evaluation of the tubing microstructure uncovered clear evidence of widespread creep damage in the vicinity of the rupture, including grain boundary cavitation and microfissuring (Figure 2). It was found that the tube material exhibited a relatively fine average grain size, with the average grain size being finer than ASTM No.8, suggesting inadequate solution annealing. In addition, chemical analysis of the material revealed that the nitrogen content was 0.008 weight % and the carbon + nitrogen content was 0.056 weight %, well below the 0.12% level that would be considered advisable for superior creep rupture strength.

Based on the presence of creep damage, as well as evidence of advanced sigma phase formation and the fact that the tube had operated for 50 years, it could be assumed that the failure was due to long-term overheating. However, had this tube been manufactured with an acceptable chemical composition and had it been properly solution annealed it likely would have operated for several hundred thousand additional hours prior to the onset of failures. Therefore, this failure could be considered premature due to non-optimum processing of the material.

Summary

The research that was performed over several decades has shown that the creep rupture strength of an austenitic stainless steel can be optimized when the following criteria are met:

1) The carbide forming alloys are added in a proportion to carbon that is approximately equal to the stoichiometric ratio of the carbide that forms.

2) The amount of carbon + nitrogen is a minimum of 0.12 weight %

3) The solution anneal (temperature and time) is adequate to dissolve a sufficient fraction of carbonitrides. The specification attempts to address this by requiring both a minimum temperature and a grain size of 7 or coarser.

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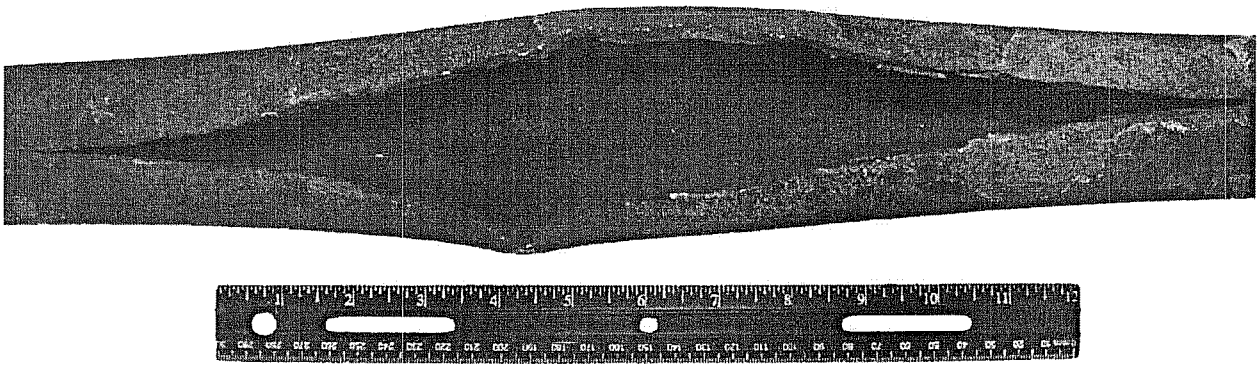
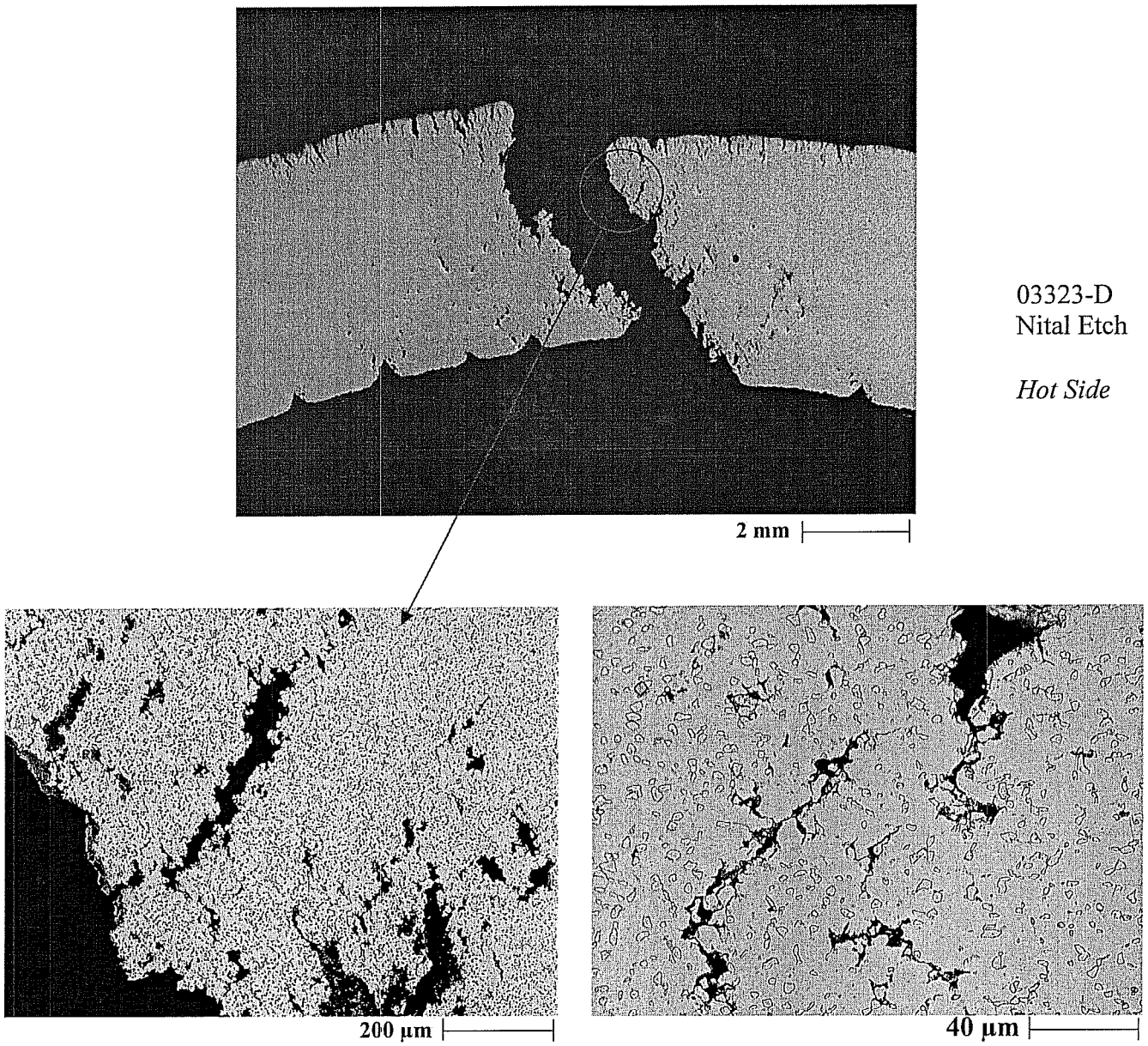


Figure 1. Documenting the Section of Failed Superheater Tubing, as it Appeared when Received from the Field.



03323-D Nital Etch *Hot Side*

Figure 2. Documenting the Damage Observed Near the Rupture Site in the SH Tube.

Remaining Life Assessment of Austenitic Stainless Steel Superheater and Reheater Tubing Subject to Longterm Overheat–Creep

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ABSTRACT

In the past decade there has been an increase in the frequency of austenitic stainless steel tube failures. The three most common failure mechanisms are stress corrosion cracking, oxide exfoliation leading to tube blockage induced short term overheating, and longterm overheat-creep failures. There was no recognized method of assessing these or the other less common failure mechanisms experienced by stainless steel superheater and reheater tubes. To overcome this deficiency, EPRI produced a guideline for the remaining life assessment of stainless steel tubing. The guidelines present roadmap approaches to assess a variety of failure mechanisms. This paper will present an overview on the method adopted in the guideline for predicting LTO-C failures.

The most commonly used method for assessing the life of ferritic superheater and reheater tubing is based on steamside oxide and wall thickness measurements. This method is not appropriate for austenitic stainless steel tubing. An alternative life assessment method was developed that relies on the prior LTO-C failure history, oxide scale and thermocouple measurements made on the ferritic tubing downstream of the stainless steel tubing, and the microstructural characteristics of creep cavitation and sigma phase thickness. Preliminary results from a cadaver study of a stainless steel secondary superheater that was recently replaced due to LTO-C failures will be presented to illustrate key attributes of the remaining life method.

INTRODUCTION

Austentic stainless steel tubing has been used for many decades for the outlet sections of superheaters and reheaters. The three most commonly used alloys are Type 304H, 321H, and 347H alloys. These alloys have in general provided excellent reliable and long term service. In the past decade, however, there has been an increased frequency of failures in the stainless steel sections of superheater and reheaters. The three most common causes of these failures are stress corrosion cracking, steamside oxide exfoliation leading to tube blockage induced short term overheating and longterm overheating, creep.

In general, the available options to address these failures have been somewhat limited due to the lack of recognized life assessment methods that can be used to predict the failure rates with and without the benefit of various corrective actions. The lack of a definitive means to assess which tube circuits/segments would fail, and when they would fail has led to numerous decisions to make wholesale replacements of the tubing.

To overcome this deficiency, EPRI developed a guideline for the remaining life assessment of stainless steel superheater and reheater tubes[1]. A summary of these guidelines was presented at EPRI's International Conference on Materials and Corrosion Experience for Fossil Plants in November 2003[2]. After the publication of the EPRI guidelines in December 2002, an opportunity to perform a comprehensive case study and validation of the methods recommended for assessing the remaining life for LTO-C damage availed itself. This paper documents this case study and a few of the key findings from this ongoing project.

Life assessment of LTO-C damage in ferritic tubing is relatively straightforward. For the past few decades most organizations have adopted the steamside oxide scale thickness method of assessing the remaining life of the ferritic SH/RH

tubing. This method has an excellent track record and has been refined to the point where it can now be used to estimate when and where failures will occur at all tube rows, assemblies and gas-touched lengths. Unfortunately this method cannot be directly applied to stainless steel tubing because the steamside oxide thickness on this tubing is thin, irregular and doesn't provide a meaningful correlation with the time/temperature history. It was obvious that an alternative method was required for stainless steel tubing.

It was also recognized that most organizations have mapped out the steamside oxide scale thicknesses on the ferritic tubing upstream of the stainless steel tubing and that if possible this information should be used in the remaining life assessment of the stainless steel tubing. The life assessment model thus began taking form using a steam temperature extrapolation/ thermal hydraulic based life assessment method that has been successfully used by the authors for the past decade that relied heavily on steamside oxide thickness surveys of the ferritic tubing up and downstream (in the outlet penthouse) of the stainless steel tubing. Additional refinements were added to the model such as allowing the effective temperature estimations derived from the metallurgical characteristics of segments of the stainless steel tubing to be included in the life estimations.

DESCRIPTION OF THE UNIT BEING EVALUATED

John Amos Unit 3 is a 1375 MW (1300MW nominal) Babcock & Wilcox universal pressure UP-101 unit that entered commercial operation in 1973 (~200,000 hours of service). The unit is owned and operated by American Electric Power (AEP).

The secondary superheater (SSH) consists of 146 pendant elements. Each element contains ten circuits with each circuit making two passes (Figures 1 and 2). The outlet passes are imbedded between inlet passes and are comprised primarily of Type 321H stainless steel. The outlet passes feed two superheater outlet headers.

The SSH outlet tubing is specified as SA 213, Grade 321H with measured dimensions of 1.75 inches outside diameter and 0.298" inch or 0.275" thickness. The main steam is designed to operate at 3845 psig/ 1010°F/ 9,775,000 lbm/hr.

In March 2003 a few months after two LTO-C failures in the stainless steel portion of the SSH, the center 80 elements 20 feet of the TP 321H material in the tenth tube from the front were replaced starting approximately 24 inches below the roof.

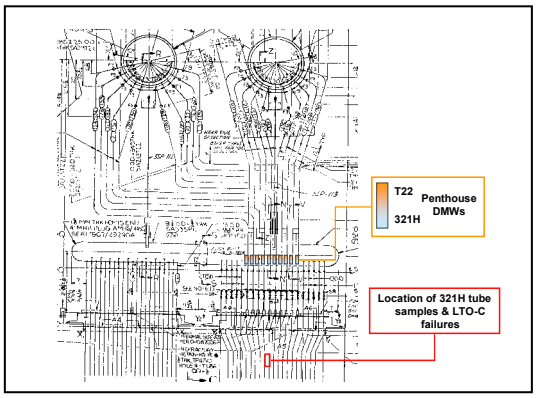


Figure 1 – Layout of the intermediate header, secondary superheater and two outlet headers. There are five T22 tube circuits at the front and rear of the secondary superheater (Rows 1 through 5 and 16 through 20). Near the bottom of these downflow rows is a T22 to 321H dissimilar metal weld. The final upflow tube legs (Rows 6 through 15) are 321H tubes.

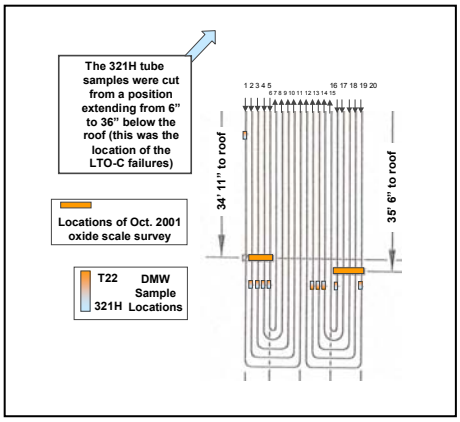


Figure 2 – Layout of the bottom portion of the SSH showing the furnace DMWs and locations of steamside oxide thickness surveys.

The entire secondary superheater was replaced during the Spring 2004 outage because of repeated failures and an uncertainty in the remaining life of the stainless steel portion of the elements in this unit and in sister units.

Historical records indicate that the SSH has experienced three tube rubbing failures, seven short-term overheat failures, two tube-to-header fatigue failures, and four longterm overheat-creep failures. The two recent failures attributed to long term overheat-creep (Figure 3) have occurred in the stainless steel outlet leg tubes.

The two recent LTO-C failures occurred between 28 to 32 inches below the roof in the pendants located 16 elements to the left and right of the center of the boiler.

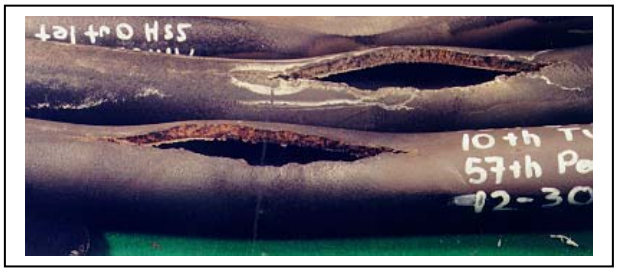


Figure 3 – LTO-C Failures in Row 10 of 20, Element 57 and 89 of 146

Following the two recent LTO-C failures that occurred in December of 2002 and January of 2003, AEP alerted EPRI of their decision to retube the SSH and indicated that they would be interested in participating on a "cadaver study" of the sections of austenitic stainless steels tubes that were being replaced. EPRI generated interest and obtained funding for a group sponsored project to perform a post mortem study of the SSH tubes. The objective of this project is to provide a detailed case study and validation of EPRI's guidelines for the remaining life assessment of austenitic stainless steel superheater/ reheater tubes subjected to LTO-C damage.

CONDITION ASSESSMENT

In spring of 2004, ultrasonic steamside oxide thickness measurements were made on all 1460 SSH outlet penthouse tubes. These measurements were made on the chromium molybdenum alloy tubing approximately 2 feet above the final penthouse DMWs The results of these measurements for Rows 6 through 10 and 11 through 15. are shown in Figures 4 and 5 respectively. As anticipated, the tube circuits that wrap around the leading edge of the SSH (i.e., Rows 6 through 10) have somewhat thicker steamside oxides compared to the circuits that wrap around the trailing edge of the SSH.

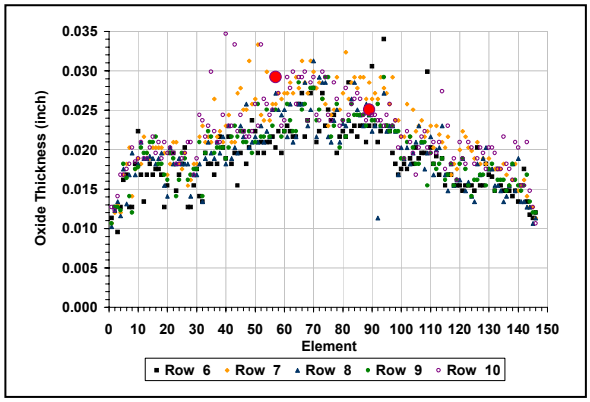


Figure 4 – Steamside oxide scale thickness for the Row 6 through 10 penthouse tubes. The red circles are the two Row 10 elements that experienced LTO-C failures.

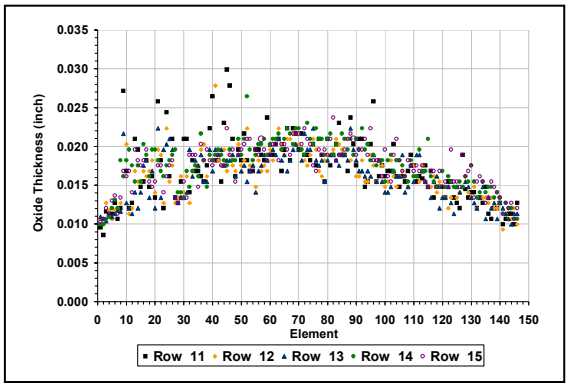


Figure 5 – Steamside oxide scale thickness for the Row 11 through 15 penthouse tubes

In the furnace, steamside oxide scale measurements were made in selected pendant element at locations just upstream of the T22 to 321H DMWs. For most tube rows, the DMWs are approximately 35 feet upstream of the location of the recent LTO-C failures. The furnace tube steamside oxide thickness measurements had been made in October 2001, whereas the penthouse tube measurements were made approximately 3-1/2 years later, in Spring 2004. Different NDE contractors made the penthouse and furnace measurements. Figure 6 presents the measured steamside oxide thickness values for Rows 2 through 5 (i.e., the circuits that feed Rows 6 through 9).

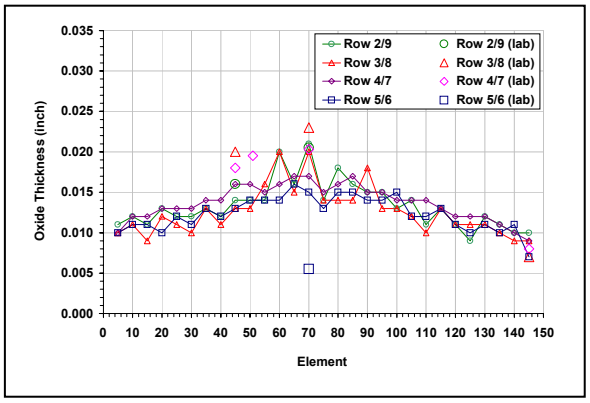


Figure 6 – Steamside oxide thickness measurements made in October 2001 on the T22 side of the furnace DMWs. The laboratory measurements shown were made on tubes removed from service in Spring 2004.

METALLURGICAL EVALUATIONS

During the recent Amos 3 SSH retubing, approximately 60 three-foot long sections of TP321H tubing at the elevation of the LTO-C failures and 60 furnace DMWs were removed for laboratory metallurgical evaluations and testing. The tube samples were selected from tube circuits perceived (from the furnace and penthouse steamside oxide measurements) to have severe, moderately severe, moderate and low levels of damage and which for the most part were original rather than replaced sections of tubing.

Laboratory testing is ongoing. The evaluations being performed include:

- Steamside oxide thickness measurements on the ferritic side of the DMWs
- Chemical analysis of the TP321H samples
- Dimensional measurements
- Microstructural evaluation of the TP321H samples
- Accelerated creep rupture tests of the TP321H samples including some interrupted tests to be used to document the evolution of microstructural changes

<u>DMW steamside oxide evaluations</u>

Laboratory measurements of the steamside oxide thickness on the T22 side of the furnace DMWs were made at 8 equally spaced positions around the tube circumference. The maximum measured steamside oxide thickness values for selected DMWs are included in Figure 6. The laboratory measurements were within approximately +0.0055-inch to –0.0020-inch of the ultrasonic readings. As expected, the measured oxides were in general somewhat thicker than the field readings that were made approximately 3-1/2 years earlier.

Review of the patterns of steamside oxide thickness revealed some unusual features that were probably not considered during field ultrasonic measurements. Specifically, it was found that the location where the thickest steamside oxide scale was located was at times in an unanticipated position on the tube. Normally the steamside oxide thickness will be greatest either on the leading edge of the tube or within the front 120-degree region of the tube. In the present case this was frequently not the situation, especially for tubes with thick steamside oxide scales (Figure 7).

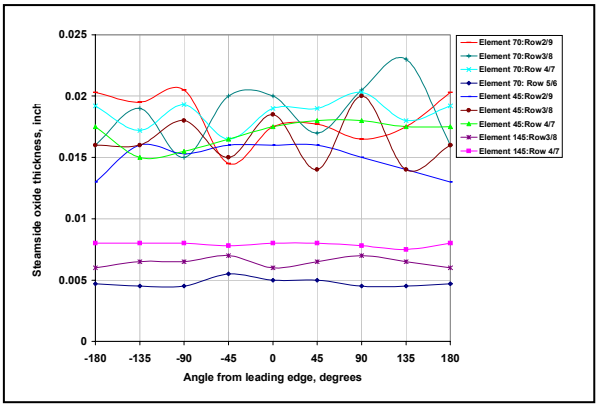


Figure 7 – Variation in steamside oxide thickness on the T22 tubing upstream of the furnace DMWs.

Understanding the oxidation kinetics of the steamside oxide scale formation in ferritic tubes is important since oxide thickness measurements are the most common method for assessing the condition of superheater tubes

Further evaluation of the unusual oxide thickness pattern revealed that there were regions around the steamside surface where the oxide had locally formed a thicker oxide. For example, steamside oxide thickness measurements for the DMW removed from Element 45, Row 2 (the same circuit as Row 9) range from 0.014 to 0.020 inch. One of the thicker oxide readings (shown below) is on the trailing side of the tube at Location F (~135° from the leading edge) exhibited a thick region of steamside oxide. (Figure 8).

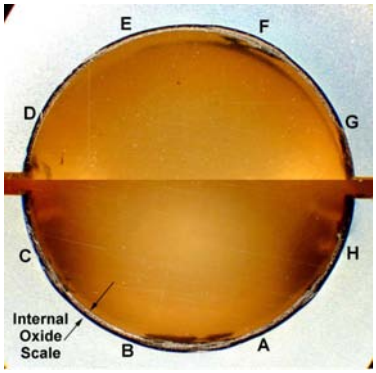


Figure 8 – Steamside oxide thickness around the inside diameter of a T22 tube upstream of a furnace DMW. Position A is located at the leading edge of the tube. The thickest oxide was located at location F, which is 135° from the leading edge of the tube.

Several regions with relatively thick oxides were apparent in this tube (e.g., Locations F, between H and C in Figure 8). These regions exhibit accelerated oxide growth kinetics. Two of these regions (Locations F, and between B and C) are limited enough in the circumferential direction that bulges into the tube metal are apparent. Thicker oxide scale and increased penetration at Location F (135° from the leading edge) is shown at a higher magnification in Figure 9.

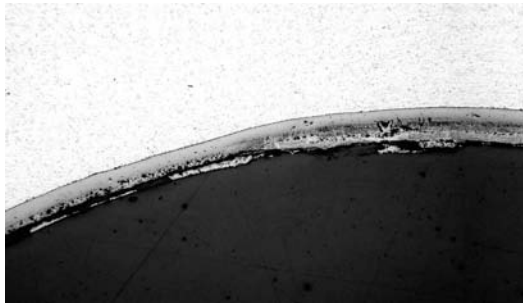


Figure 9 – Locally thick steamside oxide in the T22 tube section shown in Figure 8.

Adjacent to the locally thick region of scale the oxide exhibited the normal duplex oxide structure, consisting of a spinel layer, a porous magnetite layer and a thin hematite layer (Figure 10).

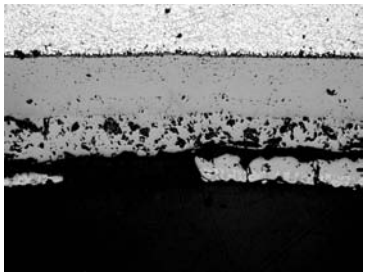


Figure 10 – Steamside oxide scale morphology adjacent to the locally thick oxide shown in Figure 9. A portion of the magnetite and hematite has exfoliated.

The region with accelerated oxide growth exhibits a lamellar structure between the spinel and magnetite layers (Figure 11). Various theories for the growth of these lamellar oxide layers have been made. One theory is that the lamellar region may be a consequence of the growth of wustite that then transforms into ferrite and magnetite during cooling to ambient

conditions.. Since the high chromium content of the inner spinel layer and the higher oxygen content in the outer magnetite layer tend to suppress wustite growth, wustite will preferentially grow between the spinel and magnetite layers in oxide scales.

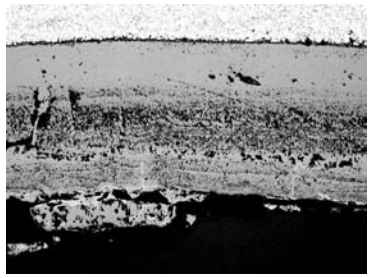


Figure 11- Steamside oxide scale morphology in the locally thick region of oxide shown in Figure 9. Note the thick laminated region located between the spinel and magnetite layers. A portion of the outer magnetite and hematite layers has exfoliated

Chemical Analysis

Table 1 provides a partial summary of the results of the chemical analysis performed on selected sections TP 321H tubing. With the possible exception of the low carbon content reported for Tube 70-3 the chemistry was within the ranges required for SA213 TP321H material.

ELEMENT	RESULTS (WEIGHT PERCENT)								REQUIREMENTS TYPE 321H
	45-2	**45-3**	**45-4**	**45-6**	**51-2**	**70-1**	**70-2**	**70-3**	
Carbon	0.06	0.05	0.06	0.05	0.05	0.05	0.06	0.03	0.04 - 0.10
Manganese	1.69	1.95	1.47	1.70	1.49	1.66	1.98	1.94	2.00 max
Phosphorus	0.023	0.024	0.021	0.022	0.026	0.027	0.023	0.024	0.040 max
Sulfur	0.002	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.030 max
Silicon	0.46	0.54	0.45	0.51	0.50	0.53	0.51	0.53	0.75 max
Nickel	9.82	10.51	10.02	11.04	10.78	11.23	10.64	10.61	9.0 - 13.0
Chromium	17.45	18.05	17.80	17.95	18.88	18.00	17.67	17.86	17.0 - 20.0
Titanium	0.50	0.43	0.48	0.39	0.31	0.42	0.31	0.36	4xC - 0.60
Copper	0.14	0.11	0.14	0.11	0.13	0.12	0.12	0.11	not specified
Molybdenum	0.04	0.28	0.21	0.15	0.03	0.23	0.12	0.29	not specified
Cobalt	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	not specified

Dimensional Measurements

Wall thickness, and inside and outside diameter measurements were made in selected sections of TP321H tubing. The maximum measured wall thickness values were in the range of approximately 8% to 12% above the specified minimum wall thickness (MWT). The minimum wall thickness values were in the range of 4% to 9% above the MWT and generally were lower in the tubes with thick DMW T22 oxide (Figure 12). A similar trend was seen for the inside and outside diameter measurements (Figure 12). The outside diameters only increased by up to 0.6% above the specified 1.75” outside diameters and would therefore be difficult to use as an effective tool to identify sections of tubing approaching end of life. The inside diameters had a more significant change (up to approximately 2.2%) with the exception of one section of tubing and seemed to have a good correlation with the DMW T22 oxide. This suggests that the commonly followed practice of measuring inside diameters during laboratory tube sample evaluations may have merit and that increases in inside diameter approaching 2% for TP321H superheater tubes may signal a need for more comprehensive condition and life assessments.

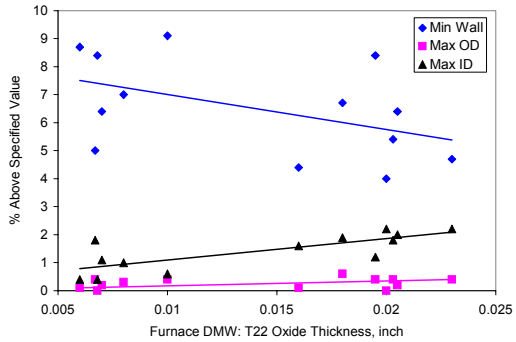
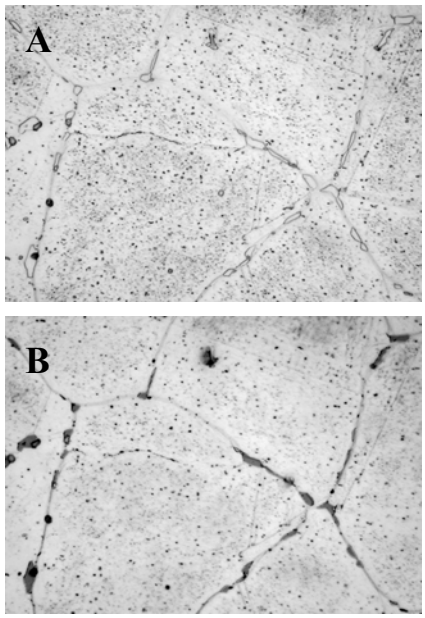


Figure 12 – A weak correlation between the steamside oxide (measured on the T22 side of the furnace DMWs and the minimum wall thickness and maximum inside and outside diameters of the TP321H tubes located approximately 40 feet downstream in the same tube circuit.

Microstructural Evaluations

Microstructural evaluation being performed on the TP321H samples include measurements of the sigma phase thickness, grain size and various characteristics of the creep cavitation including total void length (TVL) and equivalent void parameter (EVP).

Measurable amounts of sigma phase precipitate in TP321H during longterm exposure to service temperatures. This reaction provides a useful indication of the effective (i.e., lifetime average) tube metal temperature. Sigma phase is characterized for this purpose by measuring the average width of the grain boundary sigma precipitate from representative photomicrographs taken at a magnification of 1000X. Selective staining etching reagents are used to highlight the grain boundary sigma phase (Figure 13 A&B).



Figures 13A &B – Grain boundary sigma phase shown before and after selective etching. The sigma phase is selectively stained in B

Sigma phase width measurements have been made at 45° increments around the circumference of selected tubes that were in tube circuits with a range of measured T22 steamside oxide thickness values. Preliminary results from measurement made on 13 tubes show that the sigma phase thickness increases with creep cavity severity (Figure 14) but exhibits considerable scatter.

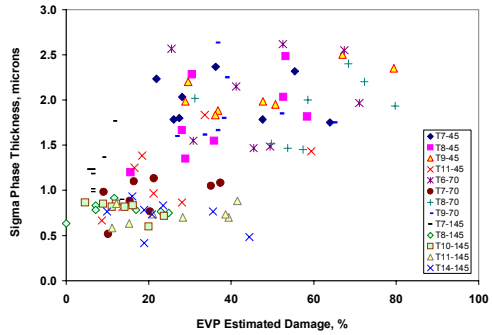


Figure 14 – Maximum sigma phase thickness in the TP321H tube compared with the creep damage fraction estimated from the creep cavity severity, EVP

Austenitic stainless steel furnace tubes are often exposed to temperatures and stresses sufficient to result in the nucleation and growth of creep cavities at the interface between sigma phase and the austenitic matrix. Density and size measurements of these cavities provide a useful method to estimate the severity of creep degradation. A special metallographic preparation technique is required to fully develop creep cavities that may be present in the steel. This technique involves multiple etch steps to remove the metal membrane that covers the cavities following mechanical polishing.

Creep cavities are characterized by their total void length (TVL) measured normal to the principal stress divided by the area examined. Photomicrographs prepared at a magnification of 500X with dimensions of 3-inch x 4-inch were used for this purpose. Because creep cavities form on grain boundaries, microstructural assessment of creep damage is influenced by grain size (GS). This is accounted for with the use of the Equivalent Void Parameter (EVP) which includes TVL and GS terms.

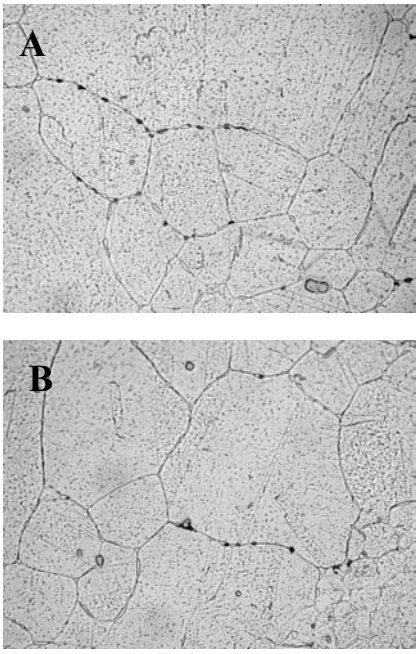


Figure 15 – Creep cavities in the leading (A) and trailing (B) edges of a TP321H tube.

Creep Rupture Tests

Creep rupture tests of selected TP321H tubes chosen for their perceived range of creep damage severity are being subjected to accelerated creep rupture tests. At this juncture only the initial, very short term "pointer" tests performed at 10 ksi and 1410°F have been completed. Tests are being performed in both the axial and circumferential directions of the tubes. As

expected, the creep rupture tests of the service degraded tube samples failed in test times well below those anticipated for virgin TP321H material (Figure 16).

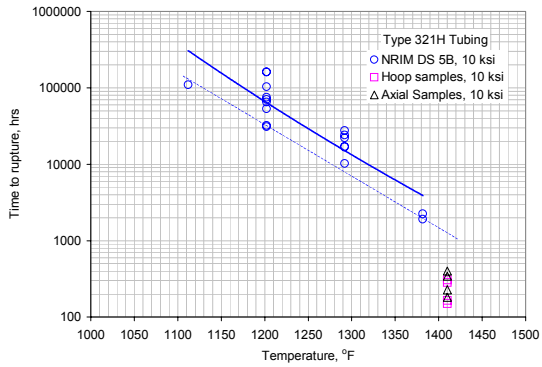


Figure 16 – Pointer creep rupture test results performed in the axial and hoop direction of four Type 321H tubes.

The test specimens tested in the hoop direction consistently failed in a somewhat shorter time than the axial specimens).

SUMMARY & ONGOING RESEARCH

A guideline for the assessment of remaining life of austenitic stainless steel superheater and reheater tubes was published by EPRI in December 2002. The guideline addresses all the common failure mechanisms experienced by Types 304H, 321H, and 347H tubing. For LTO-C damage, a roadmap approach that incorporates all the available historical information, steamside oxide scale surveys of the up and downstream ferritic tubing, metallurgical characteristics of selected stainless steel tube samples, and penthouse tube thermocouple data has been developed. The method can be used to determine when and where stainless steel tube failures will occur and the benefit of various reliability improvement corrective actions.

The metallurgical characteristics discussed in this paper are key elements of the LTO-C life assessment strategy. The T22 DMW oxides are used to estimate the steam temperatures entering and exiting specific austenitic stainless steel section of the superheater. The sigma phase thickness provides estimates of local tube metal temperatures within the austenitic stainless steel section of the superheater. The creep cavity severity (EVP) provides direct estimates of the remaining creep life at selected locations. The accelerated creep rupture tests also provide estimates of remaining creep life. The interrupted creep rupture tests are used to validate or fine tune the EVP v. creep life and sigma phase thickness v. temperature correlations for unique heats of austentic stainless steel tubing.

An ongoing project is being performed to illustrate the use of the EPRI approach for the LTO-C damage mechanism. Approximately 120 tube samples were removed from a 31 year old Type 321H SSH. Field and laboratory measurements of the steamside oxide scale on the T22 side of the DMWs both up and downstream of the stainless steel section of the SSH were made. Detailed metallurgical assessments of a range of the TP321H tube samples are being undertaken. These are being used to validate and refine the LTO-C damage models. Thermal hydraulic modelling of the SSH will also be performed to estimate the steam and tube metal temperatures throughout the SSH. These assessments will be published[3] as a case study which will illustrate the roadmap steps for LTO-C life assessment. It is anticipated that the project will be completed in 2005.

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SESSION 10: Cycle Chemistry Influences on Tube Failures

Chairman: G. Hoffman, PacifiCorp

XCEL ENERGY EXPERIENCE WITH CHEMISTRY-INFLUENCED BOILER TUBE FAILURES

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Abstract

Evaluation of boiler tube failure (BTF) statistics for Xcel Energy identified chemistry-influenced BTFs as the third leading failure category during the years 2000 through 2003. Further investigation revealed that the majority of chemistry-related BTFs involved mechanisms that were associated with heavy local waterside deposits, and that all of the failures occurred at five units, each of which experienced repeat failures. A team was formed to determine commonalities between the root cause(s) of the BTFs between the affected units, and to recommend actions for problem mitigation. Early indications suggest that some of the implemented corrective actions have been effective in reducing the likelihood of such failures in the future.

Introduction

Xcel Energy is an electric and gas utility with headquarters in Minneapolis, Minnesota. The company serves 3.3 million electric customers in eleven states, with total electric-generating capacity of about 15,433 MW from 71 facilities, utilizing a variety of fuel sources (nuclear, coal, oil, hydro, natural gas, refuse-derived, and wind).

Heavy waterside deposits are frequently associated with BTFs by the mechanisms of hydrogen damage, caustic gouging, phosphate corrosion, and nonspecific under-deposit pitting (Figures 1-8). Such deposits can also induce BTFs by long-term overheat (creep). In most cases, the formation of heavy local deposits is a common underlying precursor to failures by these mechanisms in waterwall tubes.[1-3]

Background

In 2002, Xcel Energy began developing an electronic database for recording BTF information on the company's Intranet. The database was completed early in 2003, and was initially populated with historical failures from the previous five-year period, along with ongoing recording of new BTF events. Since BTFs were the leading cause of forced outages at Xcel Energy plants, the database was soon utilized in conjunction with an EFOR (equivalent forced outage rate) reduction team to identify opportunities for EFOR improvement.

In order to capture all BTF events, failures causing forced outages and maintenance outages were combined for evaluating priority concerns. The leading cause of BTF outages was slag-related damage, with thermal damage coming in second. Internal efforts were established to focus on these failure mechanisms. The third-leading cause for BTF outages during the period 2000 – 2003 was tube failures related to chemistry. A team was established to investigate the reason for the excessive occurrence of chemistry-influenced BTFs.

Chemistry-Influenced Boiler Tube Failures at Xcel Energy

During the years 2000 through 2003, there were 50 reported outages at Xcel Energy units caused by chemistry-influenced BTFs, resulting in a combined generating loss of 719,141 MW. Of these 50 outages, 37 resulted from BTFs caused by heavy local deposits ("deposit-induced" failures), 11 were caused by corrosion fatigue failures, 1 resulted from stress-assisted corrosion, and 1 was caused by pitting.

The 37 chemistry-influenced BTFs occurred at five Xcel Energy units, as follows:

Unit A:	12 outages
Unit B:	2 outages
Unit C:	12 outages
Unit D:	7 outages
Unit E:	4 outages

For many of the unit outages, multiple tube leaks were identified and repaired, so that the 37 outages may represent more than a hundred actual tube failures.

The occurrence of multiple BTFs in given units, by the same failure mechanisms, was a repeat failure scenario that clearly warranted a significant effort directed towards problem resolution. The investigating team was initially tasked with identifying root-cause issues for each unit, correlating root-causes to identify possible common issues between units, and recommending improvements that have a low cost-to-benefit ratio.

Summaries of BTF Scenarios, Root Causes and Corrective Actions

A brief description is given of each of the five units listed above, along with a summary of historical factors relevant to the BTF problems during the period 2000-2003, probable root causes, and recommended actions for problem mitigation. All of the units have pulverized coal-fired drum boilers.

Units A and B *(located at the same facility)*

Unit A (184 MW, 2000 psi drum) began operation in 1965. The boiler experienced occasional deposit-induced failures in the 1990's, but had a significant increase in the years 2001-2003, with twelve BTF outages caused by either caustic gouging or hydrogen damage. Many of the leaks were small fissures with minimal water loss, so the unit would sometimes continue to operate for as long as two months with a minor leak.

Unit B (262 MW, 2100 psi drum) was commissioned in 1976. This unit had experienced numerous deposit-induced BTFs since the late 1980's, with failure mechanisms including hydrogen damage, caustic gouging, under-deposit pitting, and long-term overheat (creep). The BTF rate has been greatly reduced since 2000, with only two Unit outages due to chemistry-induced BTFs between 2000 and 2003. However, a recently-sampled boiler tube had a deposit weight density of 34 gms/ft^2, indicating the need for a cleaning in the very near future.

Historical efforts that may have helped to reduce or mitigate steam cycle metals transport for these units have included:

1. frequent boiler cleanings with ammoniated EDTA, including an extended multi-stage cleaning on Unit B in 2000
2. switched from hydroquinone to carbohydrazide as feedwater reducing agent (1996)
3. identification and removal / replacement of tubes with heavy deposits and/or underlying tube metal damage; for Unit B, replacement of waterwall panels from two major areas with widespread tube metal damage in 1990 / 1994 and 1990 / 1996 (same panels each replaced twice)
4. increased feedwater pH limits, and discontinued amine feed for pH control
5. installed full-flow particulate filters in 1998
6. replaced evaporator / demineralizer with reverse osmosis / demineralizer system for boiler makeup water in 2000
7. replaced copper-alloy high-pressure feedwater heaters with stainless steel (replacement completed in 2003 for Unit A, 2004 for Unit B)
8. steam sparging of condensate storage tanks (original equipment for Unit B, installed in 2002 for Unit A; began sparging tanks prior to re-filling drained boilers in 2002)

The top five most-probable root causes for deposit-induced BTF problems for both units were identified as follows, with recommended actions following each item:

1. <u>startup / layup procedures</u>
   - minimize oxygen when refilling boiler by installing an adequately-sized steam sparging line from sister unit
   - install equipment for steam or nitrogen blanketing of boiler, deaerator and feedwater heater shell-sides when possible during offline periods

2. <u>inadequate boiler cleanings</u>
   - clean boilers with more effective chemical(s) or procedure(s) for removal of heavy deposits [accomplished for Unit A with mineral acid cleaning in Spring, 2003; for Unit B, boiler cleaning planned for Spring, 2005 may use mineral acid if deposit evaluation supports the need]
   - removal & replacement of high-heat flux areas where heavy deposits and tube damage were identified [accomplished in Spring, 2003 for Unit A; ongoing major outage practice for Unit B]
   - remove appropriate tube samples for deposit weight density testing on an annual basis [ongoing]

3. <u>air ingress to condensate</u>
   - develop effective, practical plan & process for identification and correction of excessive air inleakage [in-progress]

4. <u>flame alignment</u>
   - balance flame after every major outage where burners are replaced and / or coal mills have been overhauled

5. <u>chemical choice for feedwater</u>
   - replacement of carbohydrazide overfeed with separate ammonia feed for condensate / feedwater pH control [in progress, expected completion date October, 2004]
   - monitor metals transport [ongoing]

As of 09/2004, the three most recent deposit-induced BTFs occurred on:

Unit A – 06/26/2004, 04/18/2004, 06/14/2003
Unit B – 04/19/2003, 04/13/2001, 04/13/2001

Unit C

Unit C (186 MW, 1930 psi drum) went into service in 1964. The unit had an extensive history of deposit-induced BTFs, beginning in the mid-1980's. Most failures were by the mechanism of hydrogen damage, although some occurred as long-term overheat (creep). Significant iron transport in this unit has resulted in generation-restricting iron deposits on the HP turbine.

Historical efforts that may have helped to reduce or mitigate steam cycle metals transport for these units have included:

- identification and replacement of waterwall sections containing heavy deposits / tube damage, on multiple occasions (most recently in 1999, 2000 and 2002)
- regular boiler chemical cleanings with ammoniated EDTA, most recently in March, 2002
- replacement of all copper-alloy feedwater heaters with stainless steel
- condenser tubesheet re-coated with epoxy in 2002

The top five most-probable root causes for deposit-induced BTF problems for Unit C were identified as follows, with recommended actions following each item:

1. <u>condensate / feedwater chemical selection</u>
   - replace hydroquinone (feedwater reducing agent) with either hydrazine or eliminate reducing agent; replace amines (condensate / feedwater pH control) with ammonia [testing in-progress to evaluate system response to elimination of reducing agent; hydrazine, carbohydrazide and ammonia are being added to the discharge permit for facility use]

2. <u>condensate / feedwater chemistry control</u>
   - insure condensate / feedwater pH remains in control range (primarily addressed by using ammonia for pH control, item 1.)
   - monitor metals transport to optimize chemistry control [ongoing]
   - install full-flow condensate particulate filter [in capital budget for 2006]

3. <u>inadequate boiler cleanings</u>
   - clean boilers with more effective chemical(s) or procedure(s) for removal of heavy deposits [considering either mineral acid cleaning or extended, multi-stage EDTA procedure]
   - remove appropriate tube samples for deposit weight density testing on an annual basis [ongoing]

4. <u>startup / layup procedures</u>
    - exclude oxygen when refilling boiler by installing an adequately-sized auxiliary boiler for deaerator steam sparging [in capital budget for 2006]
    - install equipment for steam or nitrogen blanketing of boiler, deaerator and feedwater heater shell-sides when possible during offline periods

5. <u>air ingress to condensate</u>
    - develop effective, practical plan & process for identification and correction of excessive air inleakage [in-progress]

As of 09/2004, the three most recent deposit-induced BTFs for Unit C occurred on:

04/23/2002, 02/08/2002, 12/16/2001

<u>Unit D</u>

Unit D (184 MW, 2000 psi drum) began operation in 1960. The unit had no historical record of deposit-induced BTFs until 2000, when the first of seven unit outages resulted from hydrogen damage, caustic gouging and phosphate corrosion. This unit experienced numerous condenser leaks only a few years after installation of new 304 stainless steel tubes in 1997.

Historical efforts that may have helped to reduce or mitigate steam cycle metals transport for these units have included:

- a boiler chemical cleaning (tetra-ammoniated EDTA) was accomplished in October, 2002; a post-clean boiler tube sample contained a heavy deposit chunk that had not been removed by the cleaning (the unit had previously been cleaned in 1994)
- waterwall tubes were tested and those identified with damage were replaced, including a major panel

The top five most-probable root causes for deposit-induced BTF problems for Unit D were identified as follows, with recommended actions following each item:

1. <u>inadequate boiler cleaning frequency</u>
    - take appropriate tube samples and proceed with necessary boiler chemical cleanings [development of management-authorized procedure in progress]

2. <u>air ingress to condensate</u>
    - develop effective, practical plan & process for identification and correction of excessive air inleakage [in-progress]

3. <u>flame alignment</u>
   - evaluate to confirm whether this is a significant issue [in-progress]

4. <u>boiler chemistry control</u>
   - adjust chemistry limits based on most recent EPRI guidelines [completed in 2003]

5. <u>condensate contamination</u>
   - replace 304 stainless steel condenser with suitable alloy [condenser replaced with SeaCure in 2004]
   - monitor cooling water contamination (condenser leaks, heating system returns) with continuous low-level sodium and cation conductivity analyzers [request for instrumentation submitted]

As of 09/2004, the three most recent deposit-induced BTFs for Unit D occurred on:

09/04/2004, 09/15/2002, 08/15/2002

<u>Unit E</u>

Unit E (178 MW, 1950 psi drum) was commissioned in 1959. The first deposit-induced BTF outage occurred in 2000, with three more occurring over the next couple of years, including a total of 15 BTFs. Most of the associated failures were by hydrogen damage, and several were at the site of previous weld-repairs.

Historical efforts that may have helped to reduce or mitigate steam cycle metals transport for these units have included:

- the boiler was chemically cleaned with tetra-ammoniated EDTA in February, 2003; it had not been previously cleaned since 1993
- waterwall tubes were tested and those identified with damage were replaced prior to the February, 2003 boiler cleaning
- fireball position was evaluated and believed to be adequate

The top five most-probable root causes for deposit-induced BTF problems for Unit E were identified as follows, with recommended actions following each item:

1. <u>inadequate boiler cleaning frequency</u>
   - take appropriate tube samples and proceed with necessary boiler chemical cleanings [development of management-authorized procedure in progress]

2. <u>pad welds / window welds</u>
   - replace any pad welds or window-welds for temporary repair of internal tube damage at the first opportunity [development of management-authorized procedure in progress]

3. <u>air ingress to condensate</u>
   - develop effective, practical plan & process for identification and correction of excessive air inleakage [in-progress]

4. <u>boiler / feedwater chemistry control</u>
   - adjust chemistry limits based on most recent EPRI guidelines [completed in 2003]

5. <u>condensate contamination</u>
   - monitor cooling water inleakage with continuous low-level sodium and cation conductivity analyzers [cation conductivity installed, sodium analyzer requested]

As of 09/2004, the three most recent deposit-induced BTFs for Unit E occurred on:

03/27/2004, 12/27/2002, 11/23/2002

Commonalities

An important function of the investigating team was to evaluate whether systematic deficiencies could be identified. Therefore, the "top five" root causes for each unit were compared, and the following correlations identified:

- Inadequacy of boiler cleanings was considered a primary issue for each of the five boilers. In some cases the cleanings were inadequate due to failure to remove heavy deposits (Units A, B, C, and D); in other cases, they were inadequate because they were not accomplished when needed, in spite of recommendations to do so (Units D, E).

- Condensate / feedwater / boiler chemistry issues were considered primary contributors to the BTFs for all units. Problem issues included selection of non-optimal chemicals for use (Units A, B and C), non-optimal control ranges (Units D and E), condensate contamination by air inleakage (all units), and condensate contamination by condenser tube leaks or other return flows (Units C, D and E).

- Inadequate shutdown – layup – startup procedures and practices were considered primary contributors to BTFs in three of the five units (A, B and C).

- Flame alignment was considered a primary contributor in three of the five units (A, B and D).

Additional Recommendations

In addition to the recommendations listed above to address specific root causes, the investigating team endorsed the following items:

⇒ Management endorsement of internally-developed "Best Practices" documents for cycle chemistry, boiler chemical cleanings and on-line instrumentation.

⇒ Develop a "Best Practices" guidelines for off-line periods.

⇒ Investigate and document the root cause(s) of each cycle chemistry contamination event.

Conclusions

An excessive number of repeat boiler tube failures induced by heavy internal deposition at Xcel Energy have occurred; the issue has been evaluated, and corrective actions have been partially implemented. The primary common root causes between the five affected units are associated with (1) inadequate boiler chemical cleanings and (2) condensate / feedwater chemistry issues. Improvement has been seen in the rate of BTFs by this cause since mitigation recommendations began to be implemented during 2003; however, full implementation of recommendations is necessary to increase the likelihood of long-term problem resolution.

Acknowledgements

Xcel Energy chemistry, engineering and operations personnel acquainted with the affected units were instrumental in identifying critical issues associated with deposit-induced BTFs at each unit.

Technical information from EPRI was used extensively in evaluating chemistry and BTF issues, and in the selection of cost-effective mitigation options.

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Chemical Cleaning and Steam Generator Tube Failure Prevention

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Abstract

Preoperational cleaning of the steam generators of new fossil units is generally advisable to assure that waterside surfaces will quickly form the protective oxide film needed to provide corrosion protection. In addition, effective preoperational cleaning can shorten the commissioning period. Recent experience has shown that preoperational cleaning justifies the initial cost. Such cleaning is an important initial step in a total program of total water chemistry control program with consequential unit availability and reliability benefits.

Several steam generator waterside tube damage mechanisms require the presence of deposits. While an optimized cycle chemistry program can minimize deposition on waterside surfaces of generating tubes, timely operational cleaning may be needed to prevent damage and failures. In some instances, cleaning of steam tubing may be considered to extend the useful service life of superheaters and reheaters.

Case studies are presented addressing methods used for some recent preoperational cleanings along with associated costs, startup/operational impacts and benefits.

Introduction

Cleanliness of waterside and steamside surfaces has a direct impact on fossil unit availability, reliability and efficiency. For optimum performance and profitability, cleanliness should be a goal throughout the entire life cycle of the unit, beginning with

design specifications and continuing through fabrication of components, packaging and shipping, unit construction and commissioning, and during all phases of operation. Timely chemical cleaning of steam generators and other cycle components assures continued satisfactory performance. Cleaning requirements will vary with many factors, including the following.

- Unit design
- Equipment fabrication specifications
- Construction practices
- Selection and optimization of operational feedwater and boiler water chemistry
- Chemistry surveillance capabilities
- Response to water chemistry excursions
- Protection of the cycle during outages with proper layup methods
- Operation and maintenance practices

Guidance on these subjects is available in EPRI publications. [1-7]

Tube failures represent a significant source of availability loss in many fossil units. A substantial fraction of these failures have been documented to involve cycle chemistry; many of the responsible damage mechanisms require or involve deposits on the water or steam touched surfaces. [8, 9] Considerable research effort has been expended to understand the mechanisms responsible for chemistry related tube damage and failures and chemistry in fossil steam-water cycles. Keeping surfaces clean can prevent many such mechanisms from developing. On the other hand, cleaning the steam generator is usually a required corrective action when tube failures have been experienced due to many of these mechanisms. [10. 11]

By understanding and applying the present state of knowledge in these areas, it should be possible to completely eliminate failures involving these mechanisms. [8, 9] Industry statistics, on the other hand indicate that this is not the case at many fossil plants. [12, 13] Thus it is clear that opportunities for improvement still exist, in spite of the knowledge available and the fact that tube failures represent a significant economic burden to the plants that continue to experience them.

Steam Generator Tube Failure Mechanisms Influenced By Waterside and Steamside Cleanliness

Many of the failure mechanisms which develop on steam and water touched surfaces of steam generator tubing are dependent upon the presence of deposits. For example, underdeposit corrosion mechanisms that affect waterwall tubing only become active when surface deposits are present. Other failure mechanisms can be aided by buildup of deposit due to its effect on heat transfer and tube metal temperatures during service. In water touched tubing, most deposit material originates in the feedwater system and is transported to the steam generator during unit startups and normal operation. Most of the deposit material on steam touched surfaces is generated in situ by reaction of steam and iron in the base metal of the tubing at elevated temperatures and pressures; additional deposit material may be transported to steam touched surfaces as a result of carryover (drum units) and/or attemperation.

Waterside deposits are regarded as a root cause influence for the following water touched tube failure mechanisms. [8, 9]

- Hydrogen damage
- Acid phosphate corrosion
- Caustic corrosion
- Supercritical waterwall cracking (conventional boilers)

Practice has shown that by monitoring tube cleanliness and performing effective chemical cleanings in a timely manner, it is possible to avoid damage and tube failures by these damage mechanisms.

With some mechanisms, improper cleaning can actually act as a root cause influence. Chemical cleaning with mineral acids such as hydrochloric acid can accelerate damage at locations which have experienced hydrogen damage or corrosion fatigue damage. Use of mineral acids to clean steam generators with hydrogen damage or corrosion fatigue should generally be avoided for this reason.

The link between waterside deposition and the boiler chemistry environment is well established for hydrogen damage, acid phosphate corrosion and caustic corrosion (or caustic gouging) mechanisms. Deposits act as a concentrating medium in each of these mechanisms. Surfaces that are subject to heaviest deposition are consistently the locations at which these mechanisms first become active. With a better understanding of deposition activity, it should be possible to better define the precise operating, surface deposition and environmental conditions needed to initiate corrosion damage by these mechanisms. EPRI has begun to evaluate deposition in fossil plants. [14, 15] This research could ultimately lead to better cycle chemistry operating guidelines and criteria for determining the need to chemically clean.

The following mechanisms may also result from deficient chemical cleaning. [8, 9]

- Short term overheating in water and steam touched tubing
- Stress corrosion cracking of susceptible steam touched tubing

If tube failures by these mechanisms are experience following chemical cleaning, the cleaning activities should be assessed as part of root cause analysis efforts. In the case of overheating failures, blockage of tubing by solids will normally be observed. Migration of chemical cleaning solvent to the failure site is needed for the cleaning to be the root cause of stress corrosion cracking.

Deposits formed in service are known to exacerbate the following damage mechanisms sometimes experienced in conventional boilers. [8]

- Waterwall fireside cracking
- Fireside corrosion in superheaters and reheaters

While chemical cleaning cannot stop these mechanisms it may extend the life of damaged tubing until tube replacements or other corrective action can be implemented. Poorly planned or controlled cleanings can directly damage steam generator tubing. Such experiences are fortunately rare and guidance on cleaning is available. [10, 11]

Role of Preoperational Chemical Cleaning

Divergent opinions exist with respect to when new steam generators, particularly those for use in combined cycle units, require chemical cleaning and the extent of cleaning needed. Clearly divergent opinions exist within the ranks of the various equipment manufacturers. End user views and experiences are inconsistent. There is generally no argument that new unit and steam generator cleanliness is important but often there is not a clear understanding of the potential impacts of commissioning or operating a new fossil unit that is not clean. With respect to heat recovery steam generators, preoperational cleaning experience covers a wide spectrum from essentially no cleaning activity whatsoever to very complex cleaning regimens that address the particular design characteristics of the cycle [16, 17]. Field results attained with a given approach have been variable; cleanliness criteria and procedures applied to units at one plant site have proven to be deficient at other sites.

Varying degrees of success or lack thereof have been noted within the projects of an individual owner [18]. Similar trends have been noted among design and construction firms, equipment manufacturers, and service companies. Unsatisfactory physical cleanup of steam piping has also been experienced [19] and the effect of system cleanliness on steam tubing cleanup requirements has been identified as a factor that can extend the construction process and delay the commissioning of new combined cycle units [17].

The idea that new fossil units could, at least in theory, be placed in service without any preoperational chemical cleaning of the steam generator, is very attractive. Elimination of cleaning offers opportunities to save time and money. Such opportunities are readily seized with optimism, particularly when finances and commissioning schedules for new projects are tight. Experienced organizations in the power generation industry have suggested that such an approach could in fact be feasible [20]; under carefully controlled conditions conventional fossil units with once through boilers have, in fact been successfully specified, fabricated, erected and commissioned without preoperational cleaning [21].

Traditionally, most high pressure boilers in conventional fossil cycles have routinely been chemically cleaned prior to initial service or following substantial tube replacements; chemical cleaning of the boiler was generally regarded as a standard practice under such circumstances prior to the 1980's. However, there have been considerable advancements in tube manufacturing techniques, which, in combination with proper packaging, transportation, storage and construction practices, have in some cases permitted procurement and installment of substantial areas of the furnace of conventional boilers without the need for cleaning [11]. In spite of improvement in fabrication methods, it is very clear that preoperational cleaning of the steam generator will be needed in many cases. At least one major manufacturer of conventional boilers continues to recommend preoperational cleanings, including an iron removal stage, prior to commercial service operation [22].

A 1998 seminar presentation [23] considering the development of reliable combined cycle plants made the following comment with respect to preoperational cleaning of HRSG: "Post construction chemical cleaning of water side components and steam purge of pipes is extremely important to long term durability of HRSGs. Many HRSGs which were not thoroughly cleaned have suffered corrosion and freeze damage from failure to completely drain while shutdown due to clogging of maintenance drains." There is a clear implication in this statement that many HRSG have not been delivered in a clean condition. As ultimate responsibility rests with the owner, it is incumbent on owner personnel to assess the cleanliness of their new equipment and, if unsatisfactory, be able to determine how it may be made satisfactory. A 2003 EPRI publication examines the subject of delivering reliable HRSGs from various aspects [24]. HRSG tube failure experience to date indicates that, in many cases, combined cycle designs did not carefully consider failure prevention and that unsatisfactory tube cleanliness may have contributed to some of the damage and failures experienced [9].

Unsatisfactory cleanliness of the steam generator (or other cycle components) cleanliness can adversely impact operation of a new fossil unit. In new combined cycle units, the following general types of contaminants may be present [18].

- Construction materials, including blasting media, other abrasive media residues, weld slag and welding consumables
- General debris such as construction materials not listed above (such as flashlights, batteries, hard hats, gloves, cups, paper, plastic, tape, etc.), dust and dirt
- Preservatives and lubricants, including those applied for corrosion protection and to facilitate construction efforts
- Non-protective metal oxides including mill scale formed during fabrication or field welding, and oxides formed during corrosion of unprotected metal surfaces

The impacts experienced will be dependent upon the extent to which steam and waterside surfaces of the units are contaminated during fabrication and construction activities, and characteristics of these contaminants. Ultimately, the actions taken or not taken to appraise the condition of the unit and apply cleaning measures as needed to improve it prior to commissioning, performance testing and initial commercial service operation will determine the severity of any deficiencies in cleanliness.

The consequences of failing to assure that steam and waterside surfaces of new combined cycle units are clean prior to commissioning can be both short term and long range in nature (Table 1). Short term impacts are of great concern to all parties involved in projects to develop a new commercial unit because they have the potential to extend the schedule and increase the cost of completing the project.

For economical (both timely and effective) commissioning, performance testing, warranty compliance and early commercial operation of new combined cycle units it is necessary to consider the cleanliness of the entire steam-water cycle. Long range impacts will generally be more problematic for the owner/operator of the unit. In many cases, impacts may be important both prior to and following commercial operation of the unit.

General Considerations for Cleanliness in New Fossil Units

In order to maximize combined cycle unit cleanliness and, in so doing, minimize possible impacts, it is most important to begin considering cleanliness of the steam-water cycle almost from the point of conception of the unit. The process must continue with a high level of importance through all ensuing phases of the project. This is a small but very important part of the broader message of the EPRI report entitled *Delivering High Recovery Heat Recovery Steam Generators* [24], which focuses on how

making proper choices during preparation of owner equipment specifications and the subsequent engineering/design, procurement and construction (EPC) process, in combination with the requisite unit commissioning activities can result in units that are more reliable during commercial service.

Specification

The owner equipment and installation specifications must include language that clearly indicates the intent to proceed in a manner that will assure high levels of cleanliness during all phases of the project. Included here are preferred fabrication techniques, transportation and storage criteria and cleanliness quality assurance requirements. It must be recognized that a general statement of intent or philosophy is not sufficient to assure that equipment will be in the high state of cleanliness desired for commissioning activities. An action plan must be included in the specification to identify all methods and procedures to be followed to meet the stated cleanliness requirements. Responsibilities for quality assurance need to be clearly defined. The final preoperational cleaning requirements must be clearly stated and their acceptance with less than complete preoperational cleaning will depend on findings of equipment cleanliness assessments resulting from scheduled inspections and quality checks conducted during the construction process.

Engineering/Design and Procurement

These activities must be coordinated so as to best assure that high levels of initial cleanliness are assured in all steam cycle components prepared for shipment to the plant site. With respect to steam cycles the following points should be stressed.
All ferrous construction is required; copper alloys should not be used except, perhaps in water cooled condensers.
Use of milling as a carbon steel fabrication method should be prohibited or discouraged as this will result in mill scale formation.

Hot working of carbon steel during fabrication should be minimized to the extent possible as hot working produces a non-protective iron oxide layer on surfaces.
Use of lubricants during fabrication should be minimized; where necessary, use of water-soluble lubricants is preferred.

Use of greases as a preservative should be avoided in favor of either vapor phase inhibitors or desiccants.

Tube ends should be securely capped prior to shipment; other openings, such as those in drums and headers should also be sealed.

An inspection of all fabricated, preserved and sealed assemblies should be made prior to packing and shipment.

If the procurement activity does not result in shipment of assemblies that are essentially free of mill scale and non-protective iron oxides associated with hot working, it is very likely that preoperational cleaning of the HRSG should include an iron removal stage, regardless of quality measures taken subsequent to receipt of the assemblies at the construction site.

Transportation, Storage and Construction

The high levels of component cleanliness achieved during the specification, engineering/design and procurement phases of the project can be nullified by poor practices during transportation, storage and construction activities. Steam cycle components should be re-inspected as soon as possible following delivery to the construction site, particularly if the construction schedule will require that they be placed in storage. This inspection affords the opportunity to verify that the actions taken to protect the assemblies prior to shipment have been effective. The initial effort should be to determine if tube caps or other component sealing techniques applied at the final assembly shop are missing, loose, broken or otherwise breached. Breached or otherwise compromised areas should be examined further, at least visually and if desired with fiber optics equipment to assess the extent of corrosion and loss of preservative that may have been experienced.

If there appears to be only incidental damage, it may be possible to restore the intended preservation conditions and store the effected assemblies until they are needed. If damage appears to be more serious, inspection of a small sample of the assemblies that appear to be properly packaged should be made to determine if they have sustained similar damage to that noted in the breached assemblies. If severe damage exists but is limited to a few assemblies it may be possible to either obtain replacement assemblies from the supplier or clean these assemblies prior to installation.

Construction

Unit fabrication and erection activities are another phase during which HRSG and combined cycle unit cleanliness can be impacted. There are several actions which can help to maintain HRSG cleanliness, mainly for preoperational cleaning and commissioning activities but also for future operational cleanings.

- Verify that assembly unpacking procedures are understood and carefully followed throughout the process.
- Ensure that welding and other hot work procedures specified for construction are adequate and properly followed; this will minimize formation of non-protective iron oxides.

- Field welding and related activities should strive to avoid creation of flow disruption sites, which are likely to be subject to deposition activity during service; these locations often serve as initiation sites for underdeposit corrosion mechanisms.

- Use of organics such as lubricants and cutting oils during construction should be reviewed to ensure that contact with waterside and steamside surfaces is minimized; use of water soluble oils should be encouraged.

- Generally accepted "clean work" policies and procedures should be stressed and emphasized by including cleanliness inspections as part of the work acceptance process.

- A review of the permanent thermocouples installed on the HRSG should be made to determine their suitability to support temperature surveillance needs during chemical cleanings; if desired for the preoperational cleaning, it should be possible to arrange for installation of some temporary thermocouples near the end of the construction period.

- Water to be used for hydrostatic testing should be of high purity and treated to minimize corrosion of metal surfaces; circuits should be drained completely upon completion of the test unless the unit can be placed in a proper wet layup condition [(25)].

- Prior to acceptance of the HRSG, a final inspection of the drums and headers should be made to ensure that the preoperational cleaning activities planned will be sufficient and will proceed in a timely manner.

With conscientious efforts to follow approved construction procedures and apply commonly recognized and accepted "good housekeeping practices" the steam cycle cleanliness requirements should not be significantly compromised. However, it must be kept in mind that results are not always consistent with intentions as is clearly indicated by the field and survey results presented earlier.

Preoperational Cleaning Activities

There is general agreement that preoperational cleaning should allow for flushing of all surfaces (except for those within the steam turbine) that will be contacted by cycle water and steam during unit operations. Additional cleaning of the steam generator, feedwater piping and/or steam piping may be performed as needed after flushing has been completed. The final preoperational cleaning activity is to thoroughly clean the steam lines, typically via steam blows or in some instances by alternative methods deemed satisfactory by the steam turbine supplier.

Flushing

The success of subsequent preoperational cleaning activities as well as unit commissioning efforts is influenced by the effectiveness of system flushing activities. Flushing is needed to remove most of the loose solids present in the system following unit construction.

Any residual solids not removed by flushing can lead to problems during unit operations.

- Erosion damage to metal surfaces.
- Plugging and/or flow restriction in valves, orifices and small diameter lines, including blowdown piping, drain lines, chemical feed lines, attemperation lines, instrument lines, sample lines, etc.
- Needless consumption of chemicals used in subsequent cleanings activities.
- Deposition in evaporators during commissioning and early commercial service operation.

Flushing with water, air and air/water mixtures has been practiced. Movement of the fluid creates drag forces capable of transporting loose solids out of the system or to low flow areas where they may be easily removed by other methods. Flushing effectiveness depends on velocities achieved since drag forces are a function of fluid velocity. For most applications, a minimum flush velocity of around 3 ft/s (0.9 m/s) is needed.

In many new units surfactants are added to the flush water to simultaneously remove organics present on surfaces being flushed. Heating of the treated flush water improves the detergency further enhancing removal of organics. With proper application of modern fabrication and construction methods, this approach is usually effective. However, if oils and greases are applied during construction, particularly during assembly of the HRSG, additional cleaning may be required to ensure that all organic residues have been removed from the effected surfaces.

Chemical Cleaning

Chemical cleaning is practiced principally to remove adherent and generally non-protective iron oxides from metal surfaces; the extent of such oxide accumulations is dependent on the effectiveness of the "clean construction" techniques selected and applied. However, the cleaning solvent s used to remove these oxides will also dissolve iron and other metals present in any loose solids remaining in the system after flushing.

In some instances it is possible to add surfactants to these cleaning solutions to remove any organics that are present; generally such action would be considered in cases where initial flushing was performed without surfactant additions. Removal of oils and

greases may be accomplished by an alkaline boilout, where alkaline chemicals are dissolved, added to the component to be cleaned, and circulated at temperatures high enough to assure natural circulation – unless circulation will be assured by other means. Such an approach, which was considered mandatory with older fabrication and construction methods, should be applied when high levels of oil and grease are known or suspected to be present. At least one manufacturer recommends that an alkaline boilout of the HRSG economizer and evaporator circuits be performed as part of the normal preoperational cleaning activities [26].

The need for cleaning of steam generators for removal of iron oxide deposits (and any mill scale that may be present) from water-touched surfaces of new fossil units is the aspect of preoperational cleaning most commonly omitted. This is done to avoid the time and costs associated with the iron removal solvents and procedures.

As mentioned previously, results with respect to preoperational cleaning are mixed. For project planning purposes, including an iron removal step as part of the preoperational cleaning activity is prudent. This can be implemented in parallel with an action plan designed to assure equipment cleanliness; results of such programs must be verified by means of quality checks and inspections. Such an approach assures that the appropriate quality checks are made and that resources for a chemical cleaning for iron removal are available in the event such cleaning is needed.

In cases of new combined cycle units where preoperational cleaning to remove iron was performed, the extent of cleaning has varied widely. In some cases, cleaning has been restricted to the evaporator and possibly economizer circuits, as was generally the practice in older fossil units with conventional boilers. In some combined cycle unit, cleaning to remove iron has been applied to most of the feedwater system, typically including all piping beyond the evaporator feed pump including the attemperation lines, as well as the entire HRSG, including superheater and reheater circuits and frequently the steam piping to the turbine isolation (stop) valves. Advocates of extensive cleaning for iron removal from new fossil units argue that the cost of cleaning is justified by shorter and more predictable steam blow and commissioning periods [17]. It also appears likely that following this approach will offer additional value with respect to unit performance. In combination with proper selection and control of the chemistry, extensive preoperational cleaning of new units should effectively maximize the run time before the first operational cleaning of the steam generator is required.

Cleaning of Steam Piping

Traditionally, steam blowing has been the method of choice to remove solids from steam piping and tubing prior to initial operation of the steam turbine. There are now procedures available that address the main negative features of traditional steam

blowing methods, namely noise levels and costs. However, not all methods are equally effective and some methods may not be regarded as acceptable processes from the standpoint of steam turbine warranty compliance.

In units with turbine bypass capabilities, it is possible to operate with the bypass open until the steam is considered clean enough to be directed to the steam turbine. However, such an approach is likely to be both lengthy and costly. This approach may be considered and applied usefully if any concerns exist over residual contamination by cleaning solvent following preoperational chemical cleaning of the steam piping. It should not, however, be regarded as a substitute for such cleaning or for proper steam blowing.

Role of Operational Chemical Cleaning

Operational cleaning of steam generators should be performed as needed to assure that deposit accumulations on steamside and waterside surfaces will not allow damage mechanisms to become active or exacerbate damage by other mechanisms where corrosion rates increase at elevated tube metal temperatures. Failure to monitor waterside cleanliness and perform cleanings as a preventive maintenance activity often leads to availability loss resulting from tube damage and failures. With many mechanisms, chemical cleaning of the boiler is a required corrective maintenance activity.

In general, operational cleaning of water touched tubing, particularly generator tubing, is more likely to be needed than is cleaning of steam-touched surfaces. In the absence of external contamination, cleaning of water-touched tubing is generally directed to remove iron oxide and other metals and metal oxides transported to the steam generator during unit operations.

The iron removal solvents used for preoperational cleaning are also generally suitable for operational cleaning. However, it is good practice to assess deposit loading and composition prior to cleaning to help determine the solvents and process conditions that are needed to assure removal of operational deposits. The latest EPRI chemical cleaning guidelines present clear and concise stepwise procedures that users may apply to determine when chemical cleaning of water-touched surfaces of steam generators is required. [10, 11]

Another possible reason to operationally clean the steam generator is to recover efficiency losses attributable to internal deposits. [27] While it is generally accepted that some efficiency improvement occurs following operational cleaning of conventional boilers, quantification of this benefit has proven to be nearly impossible because of the various factors that influence steam generator performance. In combined cycle units, it is thought that changes in steam production relative to combustion turbine output should be relatively easy to measure and provide a general indication of HRSG cleanliness. The relationship between HRSG cleanliness and combined cycle reliability

is well known [24]; effects of deposits on heat transfer in HRSGs and the link to unit efficiency may be investigated as a future research activity with EPRI's Heat Recovery Steam Generator Dependability Program.

Field Experience: Case Studies

Black & Veatch (B&V) has been involved in construction, preoperational cleaning, and commissioning of many combined cycle units using heat recovery steam generators (HRSGs) over the past several years. [28] Preferred methods of cleaning have been developed based on the technologies available, costs, schedules, and the need for proven results in a timely manner. Factors for consideration include the ability to get competitive bids from several service suppliers, the ability to meet required schedules, and the need to have clean systems for smooth downstream startup activities. Equipment procurement, precleaning construction activities, and ability to dispose of cleaning wastewaters are all important aspects of cleaning that must be factored into commissioning activities. While chemical cleaning is often an unpopular part of the project, B&V believes that the cleaning methods and techniques developed have allowed achievement of consistent high performance in this area. The schedule benefits from these chemistry improvements can be worth hundreds of thousands of dollars to a project.

This success is measured in a number of areas, including the following:

1. Drum inspections that show the internals free of mill scale and well passivated, as shown in Figure 1.
2. Timely completion of cleaning activities within the schedule window.
3. Minimized waste volumes and cost-effective disposal.
4. Excellent water chemistry during commissioning and initial operation of the unit with minimal impact on startup and commissioning schedule.
5. Careful cleaning practices have allowed improvements in the cleanup time for the cycle, which has enabled B&V to complete bypass operation more quickly.

Listed below are brief summary descriptions of chemical cleaning experiences from recent combined cycle plants. These cleanings all employed citric acid for removal and included a surfactant to concurrently remove any traces of light organics present. (When heavy organics such as greases are present, an alkaline boilout step should be applied to remove them prior to proceeding with iron removal.) B&V has used both citric acid and EDTA successfully for HRSG cleanings. However, the usual solvent of preference for preoperational cleans has been citric acid as it is an effective solvent, it is more economical, and there are fewer difficulties finding disposal facilities that will accept the waste citric acid, as compared to EDTA.

Plant 1

Plant 1 is a three on one combined cycle facility unit. The cleaning process consisted of heating to 180 to 200˚F (~82-93˚C) and addition of surfactant for degrease. After a twelve hour soak, inhibitor and 3 % citric acid were added for millscale removal. Once the iron levels stabilized, the solution was cooled to 150˚F (~66˚C) and ammonia added to raise the pH to 9 to 9.5. Finally, sodium nitrite was added and circulated for four hours to passivate the HRSG. During inspection, the drums were found to be clean of sludge and the metal had the "gun metal" gray coloring of a passivated surface. Following the cleaning, the HRSG was laid up with nitrogen.

One unexpected benefit of the cleaning was that first fire of the combustion turbine (CT) units occurred with no delays due to plugging of the boiler feed pump strainers. Previous experience was that the BFP strainers would plug with iron sludge remaining in the cycle after chemical cleaning. Since the HRSG's must be in service to fire the combustion turbines, when the strainers plug, the CT must be shut down as well and its commissioning be put on hold until the strainer is cleaned out and returned to service. On some projects, this problem had taken as long as a week to overcome. So, to be able to start the CT's with no strainer delays represents a significant enhancement of the project commissioning schedule.

Once the unit reached bypass operation, cycle and steam chemistry were satisfactory and minimal delays were encountered with rolling and synchronizing the steam turbine.

The success of the chemical cleaning and the resulting benefits were among the factors that enabled the facility to reach commercial operation approximately one month ahead of schedule.

Benefits of the cleaning included initial operation of the boiler feed pumps with no shutdowns for strainer plugging and excellent startup steam chemistry.

Plant 2

Plant 2 consists of two blocks of two on one combined cycle units. For the first block, the cleaning process was similar to that used at Plant 1, but soda ash was used instead of ammonia for pH adjustment following the millscale removal step. During the drum inspection, large amounts of sludge were found on the drum surfaces (Figure 2), but the underlying metal surfaces were found to be well passivated. During the drum restoration, the sludge was washed down. This block had several shutdowns for strainer plugging during startup. However, subsequent steam chemistry was acceptable.

The cleaning of the second block used the same process, but with ammonia for neutralization instead of the soda ash. The drums were clean of sludge and metal surfaces had the expected "gun metal" gray. This block experienced minimal delays due to boiler feed pump strainer plugging. Steam chemistry was acceptable throughout the startup and commissioning.

Both blocks of this plant were completed as scheduled. As a result of the experience with soda ash, Black & Veatch has since standardized on the use of ammonia for pH adjustment of citric acid.

Plant 3

Plant 3 also consists of two blocks, each consisting of two on one combined cycle units. Again, the surfactant/citric acid/ammonia/sodium nitrite process was used. Upon inspection following the cleanings, all four HRSG's were free of sludge and well passivated. During the first block startup, the boiler feed pump strainers required cleaning twice, but on the second block, no strainer plugging problems were encountered. Both units experienced excellent steam chemistry.

Once again, the chemical cleaning was a factor in the timely completion of project commissioning activities. The first block was completed early to meet the client's needs, and the second block was completed as scheduled.

Conclusion

Chemical cleaning of fossil plant steam generators is integral to longterm availability and reliability. Preoperational cleanings address any deficiencies in the steam cycle engineering procurement and construction process while operational cleanings can prevent or reduce the severity of a number of tube failure mechanisms. Determining when and how to clean requires diligent efforts to inspect equipment and to collect representative tube specimens for laboratory assessment.

Acknowledgment

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Table 1
Possible Consequences of Deficient Cleanliness on New Fossil Units

Cleanliness Issues and Impacts		Nature of Impacts	
Issue	**Impacts**	**Timing**	**Comments**
Corrosion before commissioning	Metals transport and further corrosion during commissioning	Short term	May influence in-service transport, deposition and corrosion
Plugged drains and tubes	Forced shutdown to clear drains; tube damage	Short term	Also possible after major maintenance outages
Plugging of strainers	Forced shutdown to remove and clean strainers	Short term	Feed pump strainers of greatest concern
Solids impingement	Damage to valves and rotating components	Short term or long range	Also possible after major maintenance outages
Metals transport	Longer startups, deposition in evaporators	Short term and long range	Also possible after major maintenance outages
Silica contamination and transport	Longer startups, silica deposition in evaporators and steam turbines	Short term and long range	Also possible after major maintenance outages
Steam blows	Duration and cost frequently relate to cycle cleanliness	Short term	Alternative steam path cleaning options exist
Commissioning	Duration and cost frequently relate to cycle cleanliness	Short term	Costs and Liquidated Damages
Performance testing	Duration and cost frequently relate to cycle cleanliness; results and their interpretation may be influenced by cleanliness of system	Short term and long range	Liquidated Damages
Equipment warranties	For some components, compliance may depend on cleaning activity prior to operation	Short term and long range	Influences risk during operation
Steam generator deposition and corrosion	Long term reliability (failures)	Long range	May require operational cleaning

Adapted from Reference 11. [11]

Figure 1

HRSG steam drum after citric acid cleaning; ammonia was used for pH adjustment prior to passivation[28]

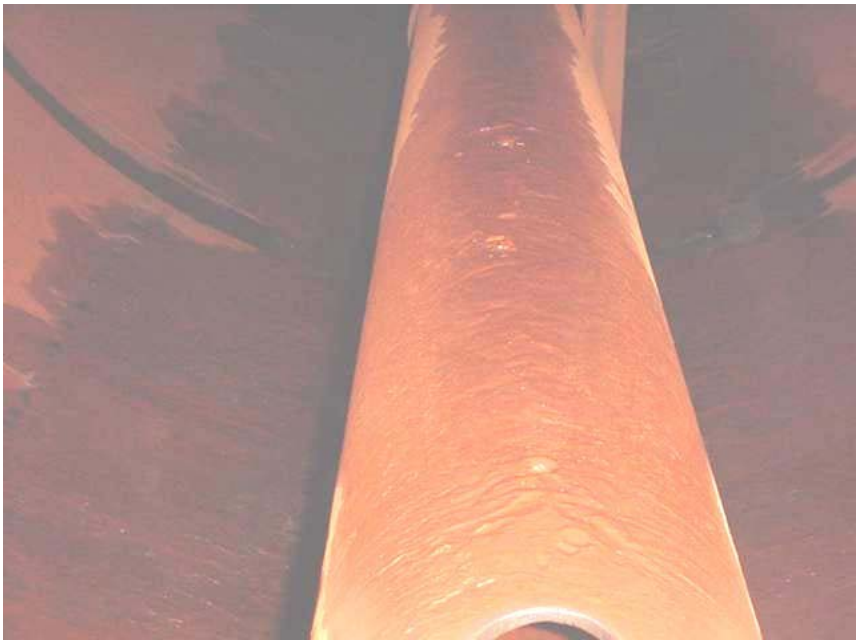

Figure 2

HRSG steam drum after citric acid cleaning; soda ash was used for pH adjustment prior to passivation[28]

INFLUENCE OF STEAM GENERATOR SHUTDOWN, LAYUP AND STARTUP CHEMISTRY CONTROL PRACTICES ON STEAM GENERATOR TUBE FAILURES

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Abstract

Advancements in the understanding and application of feedwater and boiler water chemical treatment requirements have resulted in improved control during operation of many, if not most fossil units. Research activity and field experience has clearly shown that optimal results are possible only when the proper control of the chemistry is exercised during all operational and non-operational conditions. Protective oxide layers formed on water and steam touched surfaces while in service cannot be maintained when out of service unless appropriate steps are taken to control the environment. Unfortunately, chemistry control during idle periods is not always consistent with the best practices known to protect steam generator tube waterside and steamside surfaces-as well as surfaces of other components-from corrosion. Deficient chemistry practices during unit shutdown, layup and startup are known to be responsible for or a contributing factor to many waterside tube damage and failure mechanisms and often have other detrimental impacts on unit performance. Other non-chemical aspects of fossil unit shutdown and startup are also important as these can have influence on some steam generator tubing damage mechanisms, irrespective of the chemistry practices followed.

Introduction

In order to minimize corrosion damage of steam and water touched surfaces of fossil plant components, it is essential that the environment be carefully controlled at all times. Failure to do so will inevitably lead to failures and negative impacts on unit reliability, availability and performance.

In the case of steam generator tubing and other pressure parts, failures are typically experienced during unit operation. Thus it is understandable that a high level of attention is given to control of the environment when the unit is in service. Considerable effort has been applied to understanding of the operational chemistry requirements of fossil units. [1-3]

However, many damage mechanisms involve interaction of the material with the environment at other times. The importance of protecting steam and water touched surfaces of boilers and other cycle components is also understood. [4-6] In general, organizations that operate fossil units place greater emphasis on the operational environment than on the environment maintained when generating units are not in service.

These statements on overall industry practices are supported by the recent experience of the worldwide body of chemical specialists, as captured in a survey conducted in 2003. [7] In conventional fossil plants, survey participants indicated that:

- Only 45% nitrogen blanket boilers during shutdowns.
- Only 18% provide protection to reheaters during shutdowns.
- Only 12% provide protection to steam turbines during long outages.
- Only 11% nitrogen blanket feedwater heaters during shutdown.

It should also be noted that these figures on equipment protection represent a modest improvement over results of earlier surveys of chemistry personnel on this subject.

Several organizations listed, among their two most serious cycle and chemistry problems, phenomena which typically or at least in some instances involve the chemistry environment maintained during idle periods as well as operational cycle chemistry surveillance and control. These include:

- Turbine Deposits-Copper and Other (23%)
- Boiler Tube Failures by Corrosion Fatigue (22%)
- Boiler Tube Failures by Hydrogen Damage (14%)

- Feedwater Heater Corrosion and Transport (15%)
- Iron and Copper (12%)
- Condenser Leaks (49%)

In view of these statistics it becomes evident that nearly every component in contact with water and steam can be affected if satisfactory protection is not available. More importantly, many organizations are not giving their assets the protection needed to maximize their performance.

While these statistics focus on conventional fossil units, there is naturally concern that the relatively new and growing fleet of combined cycle units with heat recovery steam generators (HRSG) will ultimately exhibit a similar pattern. To counteract this, the importance of establishing designs that facilitate protection of the equipment during shutdowns was an important theme in a recent publication which focused on delivery of high reliability HRSGs. [8] EPRI will also be developing guidelines for shutdown, layup and startup of combined cycle units in 2005.

In 2006, revision of a 1998 guideline on shutdown, layup and startup [6] applicable to conventional cycles is tentatively planned.

Prevention of Chemistry-related Damage in Fossil Units

It is now very clear that in order to assure the best fossil unit performance possible, attention to the materials and chemistry is needed throughout the entire life cycle. Key to this is making good choices during the engineering/procurement/construction (EPC) process. [8] Experience has proven time and again that doing so will simplify and shorten the commissioning period, thus setting the stage for high availability and reliability during commercial service.

Selection of the cycle chemistry for the feedwater and boiler water should be integral to the plant design activity. Initial selections should be carefully evaluated during commissioning and early commercial service operation. The selections should be periodically reassessed as the requirements of the unit will change during the service life of the unit. Improper selection of cycle chemistry initially or failure to recognize that the cycle chemistry originally selected is no longer optimal provide opportunities for damage and failure.

Similarly, early attention must be given to unit shutdown, layup and startup. The intent here is to maintain an environment that will protect the steam-water cycle. Specific requirements are dependent on unit design and choice of cycle chemistry. Thus it is very important to also periodically reassess the needs of the unit, particularly, when planning a change in the operational feedwater and/or boiler water treatment.

Unit shutdowns occur for various reasons and there should be careful consideration given as to how to optimally deal with them from the standpoint of equipment protection. Uncertainties relating to the purpose of the outage or its duration as well as the applicable procedures to be followed are frequently cited as reasons that fossil plant equipment protection is deficient. This is further complicated by the fact that outages also represent opportunities to inspect equipment, collect samples and perform necessary maintenance. The environment provided at such times generally will not be optimum for the equipment. It is therefore important to strike a balance between the needs of the equipment and the needs of personnel engaged in these activities.

Steam Generator Tube Failure Damage Mechanisms Resulting from Deficient Shutdown, Layup and Startup Practices

Over the past 20 years, considerable effort has been expended to establish an improved understanding of the basic science governing damage and failures in conventional fossil boilers. [4] More recently, a similar assessment was made for tube failures in the heat recovery steam generators (HRSG) of combined cycle units. [9] Interestingly, while many types of damage are common to conventional boiler and HRSG tubing, there are frequently important differences in the root causes.

By review of the available literature on tube failures it becomes readily apparent that many are influenced by the shutdown, layup and startup practices followed. In some cases, these practices are integral to the mechanism and have been identified as root cause influences of the damage. In others, the influence of these practices is of an indirect nature but may exacerbate the mechanism. While most of the mechanisms involve the environment during the shutdown, layup and startup periods, some are not influenced by the chemistry; equipment design characteristics and operational practices or maintenance practices are generally the issue of concern with respect to these mechanisms.

The following mechanisms are likely to be active if the unit shutdown, layup and startup practices are deficient: [4, 9]

- Pitting (Figure1)
- Acid Dew Point Corrosion (Figure 2)
- Corrosion Fatigue

Pitting attack will occur at surfaces exposed to moisture and oxygen under stagnant conditions. Sodium sulfate carryover can result in pitting in reheater circuits. Proper layup of idle units prevents pitting. Acid dew point corrosion is influenced by the fireside environment and metal temperatures during steam generator shutdown. Corrosion fatigue is a complex mechanism, with both environmental and mechanical influences. It is active during all operating modes. Proper layup is helpful since the chief environmental influences are low pH and high dissolved oxygen during startups.

Other mechanisms are active entirely or at least mainly during normal steam generator operation.

- Hydrogen Damage (Figure 3)
- Caustic Corrosion (Figure 4)
- Acid Phosphate Corrosion (Figure 5)
- Supercritical Waterwall Cracking
- Fireside Corrosion of Waterwall Tubing

These mechanisms are influenced by shutdown, layup and startup practices in that they either require or are enhanced by accumulation of waterside deposit materials. Most of this deposit material is transported to the steam generator with the feedwater; transport is most significant during startups, especially when cycle equipment has not been protected during the outage.

Hydrogen damage, acid phosphate corrosion and caustic corrosion cause failures in drum type steam generators. Waterside deposition is recognized as a root cause influence. Waterside deposition is also a root cause influence for supercritical waterwall cracking in conventional once through boilers. Waterside deposition is not a root cause influence in the case of fireside corrosion of waterwall tubing in conventional boilers; however, such accumulations are an exacerbating factor since they will increase metal temperatures, thereby accelerating the rate of corrosion.

The following mechanisms do not involve cycle chemistry. However, they may be influenced by unit shutdown and startup practices. [4, 9]

- Thermal-mechanical Fatigue (Figure 6)
- Short Term Overheating
- Fireside Corrosion of Superheaters and Reheaters
- Creep Fatigue
- Thermal Quenching-induced Fracture

Thermal fatigue is a prevalent damage mechanism in HRSGs. It can be minimized by controlling metal temperatures during unit shutdown and startup. Thermal fatigue of the economizers of conventional boilers may develop if temperatures are not properly controlled during the shutdown. [9]

Fireside corrosion is possible in the superheaters and reheaters of conventional boilers. Rapid startups can increase metal temperatures and thus intensify the corrosion damage. Creep fatigue and thermal quenching-induced fracture have been observed in HRSGs; these mechanisms involve unit operations.

The following mechanisms are not influenced by normal shutdown, layup and startup practices. They may be related to maintenance cleaning activities.

- Chemical Cleaning Damage
- Stress Corrosion Cracking

Ideally, such damage is prevented through effective control of the cleaning process. They are included here because chemistry surveillance during startup operations after cleanings provides opportunities to identify possible problems and thus take action to prevent further damage and failures while the boiler is in service. [10, 11] Chemical cleaning damage refers to attack on tubing being cleaned due to ineffective control of the cleaning process, including failure to remove all of the solvent from the steam generator before it is returned to service. Stress corrosion cracking of stainless steel tubing involves contaminants reaching the steam circuits containing these materials. Cleaning chemicals are one possible root cause; others, such as carryover of caustic to the steam circuits, are not related to unit shutdown and startup.

Effects on Other Fossil Unit Components

Steam generator tube failures are but one possible consequence of deficient shutdown practices. Other effects of concern include:

- Pitting and general corrosion of water and steam touched surfaces in condensers, feedwater heaters, deaerators, headers and piping, and turbines.
- Deposition of corrosion products on boiler feed pumps, in feedwater heaters, in orifices, in blowdown systems and on turbines
- Corrosion of the turbine in the presence of moisture, oxygen and salt deposits
- Exfoliation of steam path oxides and solid particle erosion of steam turbines
- Hideout and return of impurities and treatment chemicals

- Increased thermal stresses, strain, and vibration
- Contamination of the steam-water cycle by equipment and material used during maintenance activity

It should be noted that most of these concerns can be ameliorated through the same sort of diligence needed during unit shutdown, layup and startup periods to minimize the risk of steam generator tube damage.

Protection of Fossil Steam Cycle Components during Idle Periods

Operating experience, as reflected in the survey results of fossil plant chemistry personnel, make it clear that efforts to protect equipment during outages is often unsatisfactory. It is also apparent that some of the serious problems chemistry personnel face involve the shutdown/layup/startup period. Further, it is clear that many steam generator tube failure mechanisms, both chemical and non-chemical, are influenced by the operating practices followed at this time. The research activities of EPRI continue to yield findings supporting these observations and confirming that it is very important to maintain a protective chemical environment during shutdowns.

EPRI's Program Copper was initiated to address high pressure turbine fouling and other problems experienced by fossil units with copper alloys in the cycle. [12-15] As part of this investigation, the stability of copper oxides formed in low and high pressure heaters was evaluated by means of electrochemical studies. [14, 15] These studies showed that the copper oxides were in general less stable than the iron oxides formed on ferrous materials. Further, the most stable oxide, cuprous oxide (Cu_2O) was formed in a reducing environment, under heater operating conditions. Allowing these surfaces to be exposed to ambient oxidizing conditions, as exist during unprotected shutdowns, resulted in conversion of cuprous oxide to a less protective cupric oxide (CuO) in as little as eight hours. Figure 7 illustrates the difference in surface roughness of cuprous and cuprous oxides; copper transport is significantly greater under oxidizing conditions due to the high surface area of cupric oxide deposits.

Extensive Investigations of stress corrosion cracking (SCC) and corrosion fatigue (CF) in steam turbines has confirmed that damage typically initiates during unprotected outages due to pitting attack. A schematic representation of the influences of turbine operation and turbine shutdown is shown in Figure 8. Pit growth and onset of SCC or CF are dependent on operating conditions; however, these mechanisms cannot become active if the requisite precursor conditions associated with unprotected shutdowns are avoided. The latest research clearly suggests that protection of steam turbines during all outages is essential to avoiding the developments of pits that are the precursors to cracking via SCC and CF. [16, 17] Field experience has shown that use of dehumidified air is an effective means of preventing pitting corrosion in turbine disks and blades.

In view of the foregoing, it becomes apparent that operators of fossil units need to place greater emphasis on equipment protection during shutdowns. The objective of such action is to eliminate pitting and general corrosion damage and to maintain the stability of protective metal oxides formed during normal operation. Successful implementation of equipment protection serves the broader purpose of minimizing damage by other mechanisms which are active when the unit is in service.

The optimal protection strategy for a particular unit will naturally depend on various site-specific factors. These include unit design and operational requirements. The strategy will also need to consider the requirements of the outage and its expected duration. Regardless of the specific requirements, there are some general requirements applicable in virtually all circumstances. The following guiding principles for protection of fossil plant equipment, based on worldwide experience, need to be kept in mind when addressing chemistry control during unit shutdown.

- Ingress of air must be avoided. To accomplish this, condenser vacuum should be maintained as long as possible; this is essentially the practical duration of a short term outage.

- A means of equipment layup effective in protecting all water and steam touched surfaces must be implemented; typical options and considerations for layup are discussed in the next subsection of the paper.

- Surfaces to be maintained wet must be protected from contact with ambient air; this is typically accomplished by nitrogen blanket or, in some instances by steam blanketing.

- Chemistry requirements and procedures for wet layup must be specified, established, monitored and maintained until the unit is returned to service.

- Surfaces that cannot be effectively protected by wet layup require dry layup methods that exclude oxygen and or maintain relative humidity low enough to prevent corrosion. Like wet layup, methods for dry layup must be specified, established, monitored and maintained until the unit is returned to service.

- Water added to the cycle at startup should be of high purity and contain low levels of oxygen; unfortunately, the makeup treatment systems of many fossil plants produce water that is saturated with oxygen. This is of particular concern when the unit must be filled with water for cold startup after a maintenance outage.

Each unit shutdown should be regarded as a unique event. Equipment maintenance requirements will vary and must be accounted for when implementing cycle protection procedures.

Shutdown and Layup

There are only two major equipment design options available for conventional units, drum and once through, although there are many variables relative to pressures, temperatures and balance of plant equipment. [1, 2, 6] The situation is much more complex in combined cycle design configurations. [8, 18] Combined cycle units include, at present, one to three separate pressure designs and may include drum units, once-through units and combinations of drum/once- through units. Even though combined cycles are of increasingly complex design, the principles of layup, startup, and shutdown are similar to those used in conventional units. However, some aspects of layup, startup and shutdown will need to be modified from the guidelines given in this paper to account for unique differences in equipment, design and operation vs. conventional units. For example, combined cycle units may or may not include stand-alone deaerators, feedwater heaters and reheaters among other differences. Therefore, because of the complexities of design inherent in today's combined cycles, it is impossible to address all aspects of layup, startup and shutdown which could be encountered in modern combined cycle design. The discussion which follows will concentrate on the general principles of this topic, assuming the individual operators will have enough information from the ensuing discussion to adapt the processes described herein to fit the equipment being operated.

As previously mentioned, the two types of layup applicable to all types of units, conventional and combined cycle, are classified as "wet" or "dry". Wet layup requires the filling of most of the system with an alkaline reducing solution, generally ammonia and hydrazine, and preventing air ingress by pressurizing with nitrogen. There is one important distinction for units operating on oxygenated treatment (OT). (While OT is not presently in common usage with combined cycles, its use has gained wide acceptance for conventional once-through units and is now gaining more acceptance on conventional drum type units). The use of wet layup solutions in OT units should generally be restricted to short term protection, since the use of hydrazine is not recommended in the wet layup solution. This caveat also applies to those units operating with feedwater chemistry based on all-volatile treatment (AVT) in the oxidizing mode, AVT(O) as opposed to the reducing mode, AVT(R). (AVT(O) will have a positive ORP (oxidizing/reducing potential); the AVT(R) a negative ORP). Extended wet layup without a reducing agent in these types of units could lead to pitting attack unless the equipment is reliably nitrogen capped at all times and there is a means provided to circulate the layup solution. In view of these concerns, dry layup methods are clearly preferred for OT and AVT(O) units.

Dry layup requires draining the units while hot, and removal of all water followed by pressurization with a moisture-free inert gas (nitrogen) or by use of dehumidified air to maintain a low moisture environment. (Wet and dry layup procedures and details are further described in subsequent sections).

A generic road map that organizations may use to develop unit specific shutdown and layup procedures is shown in Figure 9. [2] Because of variations in design, some generating units may require deviations to this road map, or may require customization to adapt to a particular plant design as previously discussed. Figure 9 is divided into eight steps, which are further described as follows:

Step 1-Short-term Layup

Short-term layup presumes that the unit will be required to operate within a relatively short time frame. In consideration of this, no major changes are required from normal operating conditions, with the exception being that the unit must be protected from air ingress. The condenser vacuum and turbine seals are maintained; the deaerator and heater shells and boiler are inerted with nitrogen or steam; and, the feedwater chemistry is maintained according to the requirements of the treatment philosophy employed.

Step 2- Intermediate and Longterm Layup

Intermediate and long-term layup require additional steps to be taken to prevent corrosion during intermediate periods of layup, such as for maintenance and indeterminate cycling or peaking requirements; and during longterm layup for indefinite periods of time. Certain procedures are common regardless of whether the units are to be laid up dry or wet. There is a danger of off-load corrosion (pitting) if there are salts present. Consideration needs to be given to whether the reheater supports can take the weight if the reheater is to be filled with water.

During shutdown, the turbine, condenser (steam side) and reheater are generally considered together because, unless special facilities are provided, there is no practical way to isolate them. Generally, it is not practical to place the condenser in wet layup for a number of reasons. The reheater is evacuated by utilizing the vacuum in the condenser. The vacuum is then broken using nitrogen pressure and the condenser is drained under nitrogen.

Step 3- Dry Air Layup

The dry air layup procedure requires that all components of the system be drained. There are several methods of maintaining dry air flow through the equipment. (The equipment required for dry layup will be described later).

Step 4- Dry Layup with Nitrogen

Nitrogen can be used for blanketing equipment, which is drained but not completely dry, or for blanketing equipment either filled with water or not, to prevent air ingress. Step 4 is similar to Step 3, except nitrogen is used for a positive pressure on all components rather than a dry air purge. A small continuous purge of nitrogen is required to protect the turbine and deaerator tank.

Step 5- Wet Layup (Boiler and Feedwater Heaters)

For those units having copper alloy condenser tubes, feedwater pH should be limited to 9.0 to 9.3 by reducing ammonia. Hydrazine is held at 40 to 50 ppm. For these units, it is most important to maintain reducing conditions (ORP less than 0 mV and preferably to –350 mV) to prevent increased attack of the copper alloys associated with a change of the surface oxide layers from cuprous to cupric oxide.

Step 6- Wet Layup (Balance of Cycle)

As the turbine spins down, nitrogen is added to the condenser, which also purges the reheater system. A continuous purge of nitrogen is necessary to account for leakage through the turbine steam seals. Nitrogen is added to the deaerator and storage tank while this system is still hot. A small flow of nitrogen is provided to purge this system. A nitrogen cap is maintained on the shell side of the feedwater heaters. The superheater is back filled with a solution of up to 200 ppm hydrazine and 10 ppm ammonia.

Step 7- Very Long Storage

For very long storage periods, the reheater is isolated fuom the turbine and back filled with a solution of up to 200 ppm hydrazine and 10 ppm ammonia and capped with nitrogen. The superheater is treated similarly.

Step 8- Maintenance

Only equipment requiring maintenance should be drained (wet storage only), and nitrogen (if used) purged with air to provide an environment suitable for entry of personnel. Since nitrogen does not support human life, it is extremely important that nitrogen be completely displaced by air. The atmosphere within the equipment to be maintained should be tested with suitable test equipment to ensure the equipment is safe for personnel entry.

Wet Layup Protection Considerations Using Nitrogen

Nitrogen supply systems need to be large enough to sufficiently supply nitrogen to steam systems while pressure is collapsing during cooling in order to prevent any sub-atmospheric condition from occurring; and, to preclude any air ingress into the systems being blanketed.

Nitrogen supply piping must be connected separately to all circuits and components that are normally isolated during normal shutdown. All nitrogen piping connections must be per code requirements of the component or circuit involved. The valves can be manually operated but, preferably, they will be automatic, wired into the plant's control system so as to admit nitrogen as soon as the specified pressure set point for that component or circuit is reached. The object is always to replace the collapsing steam with nitrogen to prevent air ingress into the unit, including the condenser.

As the turbine comes off line, the condenser and reheater need to be flooded with nitrogen to achieve positive pressure as fast as possible before shutting down the air removal system. Care must be taken not to violate any turbine cooling requirements and to not over-pressurize the condenser.

The boiler should be drained under nitrogen pressure if draining is desired; or, capped under a continuous nitrogen pressure if it is to remain full. The boiler can be "flash drained" to produce a dry condition if desired, all the while under nitrogen pressure.

If other systems are to be drained, this should be accomplished under positive nitrogen pressure. A slight positive pressure should be maintained on the isolated system once the drain is accomplished. If these systems are to remain full of condensate, a positive nitrogen pressure must exist at all times to prevent any air ingress and to replace any water that may have leaked from seals, flanges, etc.

During wet layup, the oxygen scavenger concentration and the ORP must be monitored. Also, the boiler and economizer waters should be circulated on a routine basis to prevent stagnant conditions from developing.

The use of a nitrogen cap, as outlined above, improves startup chemistry, reduces layup corrosion, reduces boiler tube deposits and lengthens the time between chemical cleanings.

Dry Layup Protection Considerations

EPRI's research and inspections of many existing combined cycle installations confirms the imperative necessity of protecting the turbine from corrosion caused by ingress of air and other contaminants during shutdown periods. In nitrogen purging, a very large nitrogen system is required to provide enough nitrogen to give adequate protection to the turbine. So much so that most installed systems are incapable of meeting the requirement with originally installed equipment. In addition, many installations were not originally provided with any nitrogen equipment; or, if equipment has been provided, it is not being used to the fullest extent. Rather than adding a nitrogen system or supplementing an originally installed system to meet the demands of turbine protection, there is an alternate available - dehumidified air. This alternate is simple, reliable and may be less expensive than adding a nitrogen system or adding enough additional nitrogen storage and piping to existing systems. In addition, dehumidified air can, and is being used to provide protection to all other power plant systems.

The use of clean, dehumidified air to purge the boiler and auxiliary equipment during layup periods is routinely practiced throughout this country and internationally, for both short-term and long-term layup periods. The justification for the use of dehumidified air to protect ferrous surfaces is depicted in Figure 10, which is a plot of corrosion rate vs. humidity of air. This graph illustrates that corrosion can be mitigated by maintaining air in contact with corrosion prone surfaces at a relative humidity of

60% or less. [6] As mentioned earlier, use of dehumidified air appears to be the best approach to protect turbine steam touched surfaces from pitting attack during shutdowns.

A desiccant dehumidifier commonly used for layup of boilers and other systems is shown in Figure 11. [6, 19] The dehumidifier consists of a wheel of ceramic material that has been corrugated, so air can pass lengthwise down the fluted corrugations. A desiccant is impregnated into the structure. Moisture is attracted from the air onto the desiccant as the air passes through.

Other dehumidifier components include two fans, one each to pull the process and reactivation air streams through the wheel, a drive motor to turn the wheel, and a heater to warm the reactivation air so it can regenerate the desiccant. Finally, an electrical control panel coordinates the operation of the fans, drive motor and heater.

The wheel rotates slowly between two air streams. The first air stream is dried by the desiccant. The second air stream is heated and runs through the wheel in the other direction to regenerate the desiccant and carry away the moisture so that the desiccant remains active at all times.

The system utilized to supply dry air to the various components of the feedwater, steam and boiler circuits may be customized to adapt to various heat cycle configurations. One example for a conventional unit is shown in Figure 12. [6, 20]

Air moisture levels are checked as air enters and as it exits the reheat section. Two humidistats are installed in the return plenum of the steam side dehumidifier. They are set to turn the reactivation heaters and blower off when the returning air humidity decreases to 15% and turned on when it reaches 25%. Provision of ducts to capture and recycle dehumidified air, where feasible, offers opportunities to further protect the unit and reduce operating costs associated with dry layup, based on experience at a fossil plant with air-cooled condensers in South Africa. [21]

Unit Startup

Again it is necessary to prevent oxygen ingress if iron and copper are to be controlled to acceptable levels. The use of deaerated makeup will appreciably reduce oxygen levels during startup. Air in-leakage must be controlled as additional parts of the heat cycle are under vacuum during low load operation. The use of auxiliary steam to peg the deaerator (if available) will enhance oxygen removal at this point in the cycle.

Detection and repair of condenser leaks during startup is critical to prevent ingress of harmful contaminants such as chlorides and sulfates. Condensate polishers and/or condensate filters can markedly decrease startup times.

In general, and to the extent practical, it may be desirable to discard heater drains (if heaters are used in the cycle) during initial startup operations to reduce the amount of iron and copper entering the boiler.

Initial startup depends on the layup procedures followed prior to startup. If the layup was short-term, and the unit was filled with water treated for typical normal operations, startup can proceed without delay. If the feed water system was full of water treated for longer term layup , as shown in the road map (Figure 9) , some water may have to be dumped to reduce hydrazine (cycles with copper) and ammonia to more appropriate values.

If the unit was laid up dry, the feedwater system and boiler must be filled with deaerated water from the makeup system and treated with chemicals (ammonia and hydrazine- if used) to correspond to the normal operating conditions practiced on that unit.

During startup, the boiler feedwater should be closely monitored. The following limits for the boiler feedwater have been used as guidelines prior to firing the boiler:

- Oxygen < 100 ppb
- Iron< 100 ppb
- Copper< 10 ppb

By following the guidelines and procedures outlined above, it is expected that these limits can (and should) be reduced from those shown above. Attainment of these prefiring limits will be more difficult in units not equipped with condensate polishers and/or condensate filters. Best control will require close compliance with the guidelines outlined above for shutdown and layup.

After firing the boiler, monitoring of the condensate and feedwater must be continued, both for chemistry parameters and to ensure that temperature ramps are maintained according to equipment manufacturer's specifications.

Boiler pressure should remain at a reduced level until all chemistry limits previously established for normal unit operation have been reached. Maximum use of blowdown and condensate polishing (if available) will minimize startup times.

Conclusion

Protection of fossil plant components during idle periods is essential; failure to provide appropriate protection will inevitably lead to unit availability losses. Pitting attack is the most common of several boiler tube failure mechanisms directly or indirectly

influenced by deficient shutdown, layup and startup practices. Effective layup methods are available, though not consistently applied within the industry. Selection of the best approach to layup of individual fossil units requires consideration of site-specific factors. However, all layup procedures need to address guiding principles intended to ensure protection of idle equipment in fossil steam-water cycles.

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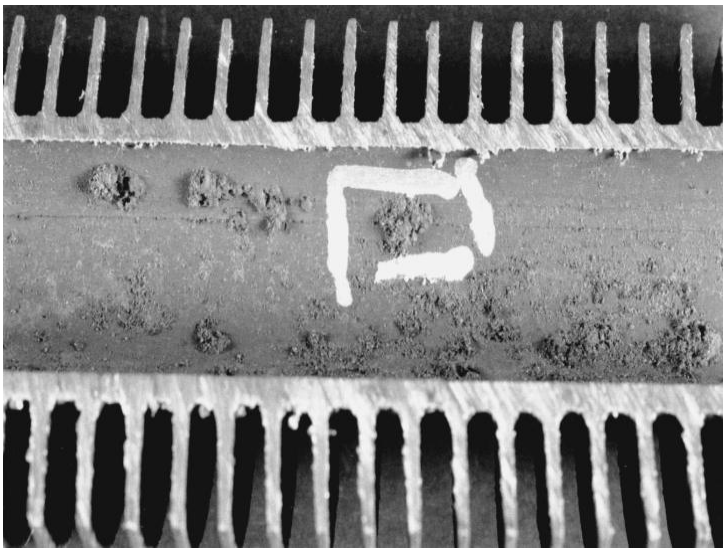

Fig. 1. Oxygen Pitting in HRSG Evaporator Tube[9]

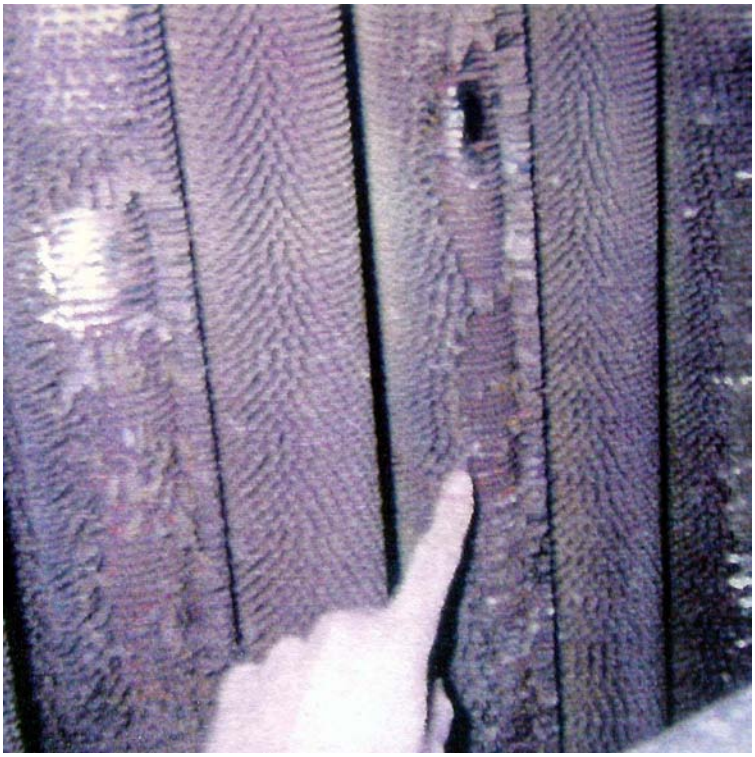

Fig. 2. HRSG Economizer Tube Fin Damage Caused by Acid Dewpoint Corrosion[9]

Fig. 3. HRSG Evaporator Tube with Heavy Deposits and Hydrogen Damage[9]

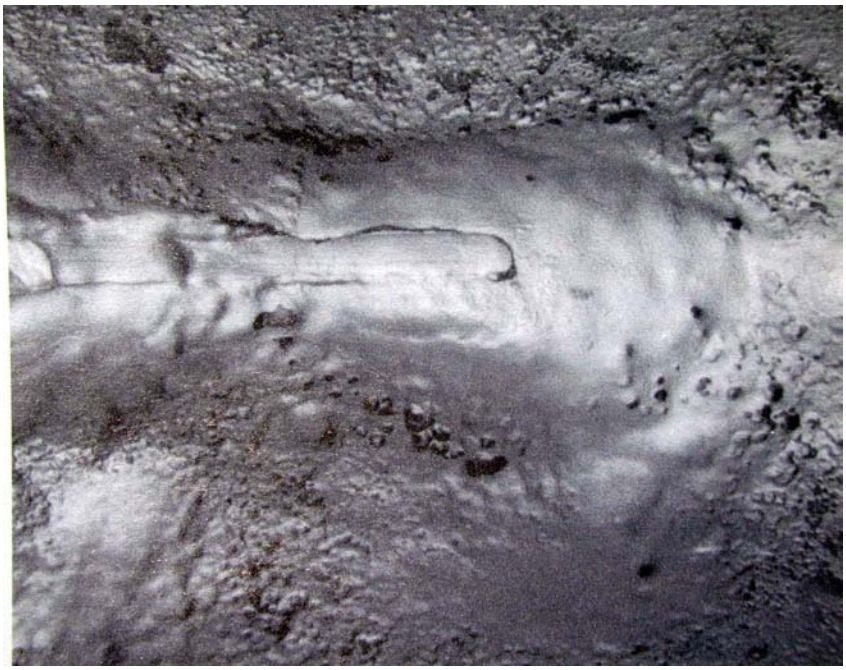

Fig. 4. Caustic Corrosion Site Revealed after Deposit Removal[9]

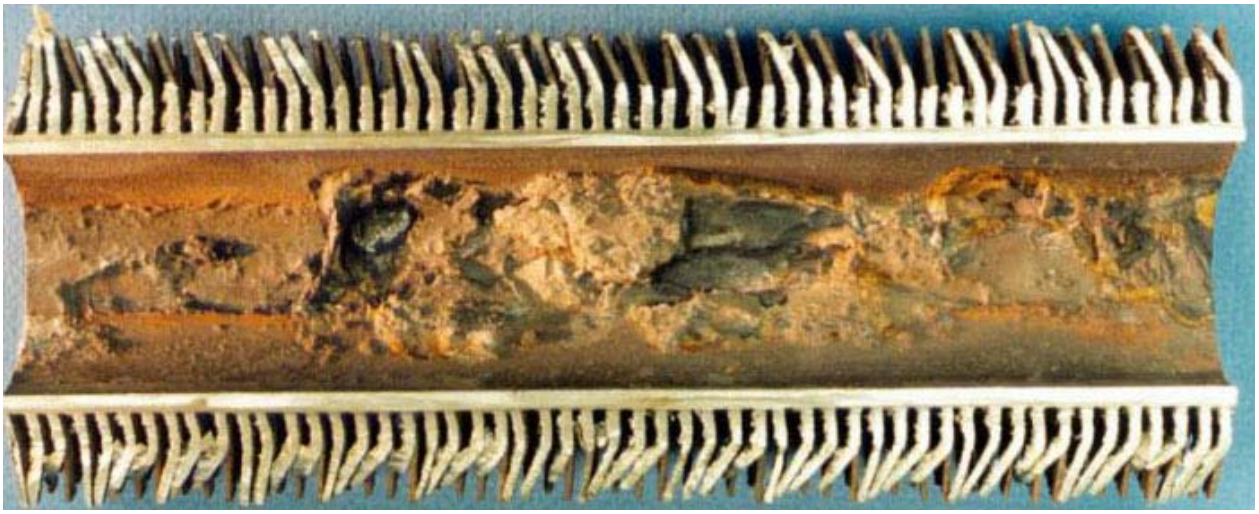

Fig. 5. HRSG Evaporator Tube with Heavy Deposits and Acid Phosphate Corrosion[9]

Fig. 6 Thermal-mechanical Fatigue Crack at Tube to Header Weld in HRSG Economizer[9]

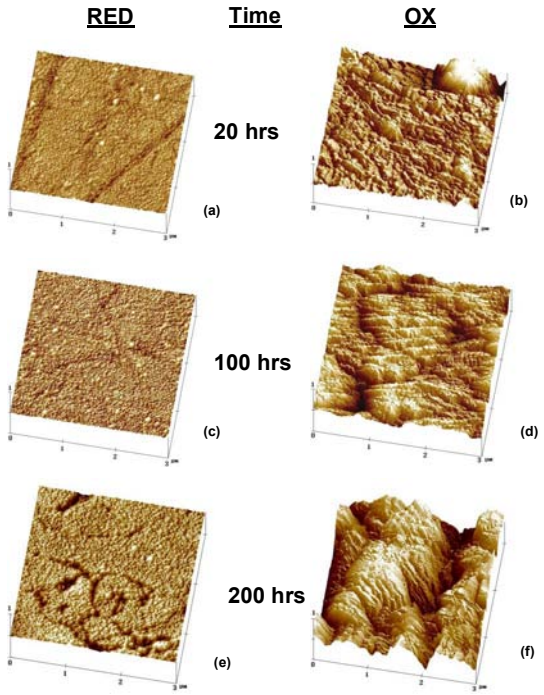

Fig. 7. Atomic Force Microscopy Images of 90/10 Cu/Ni Surfaces after Reducing and Oxidizing Treatment at 95°C (203°F)[14]

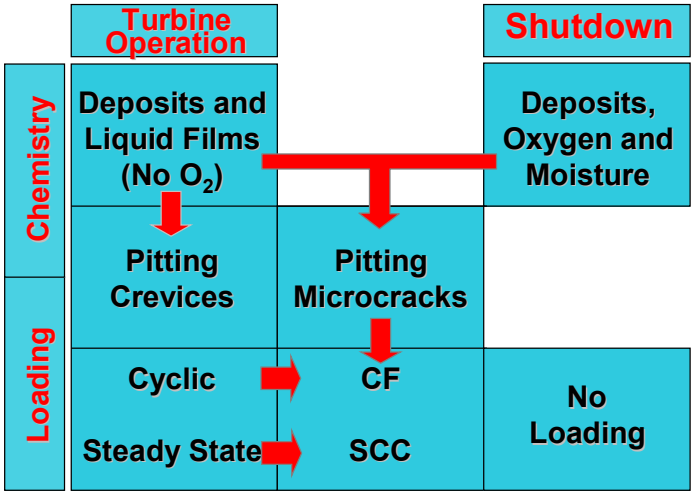

Fig. 8. Schematic of Influence of Turbine Operation and Shutdown on Corrosion Fatigue and Stress Corrosion Cracking[16]

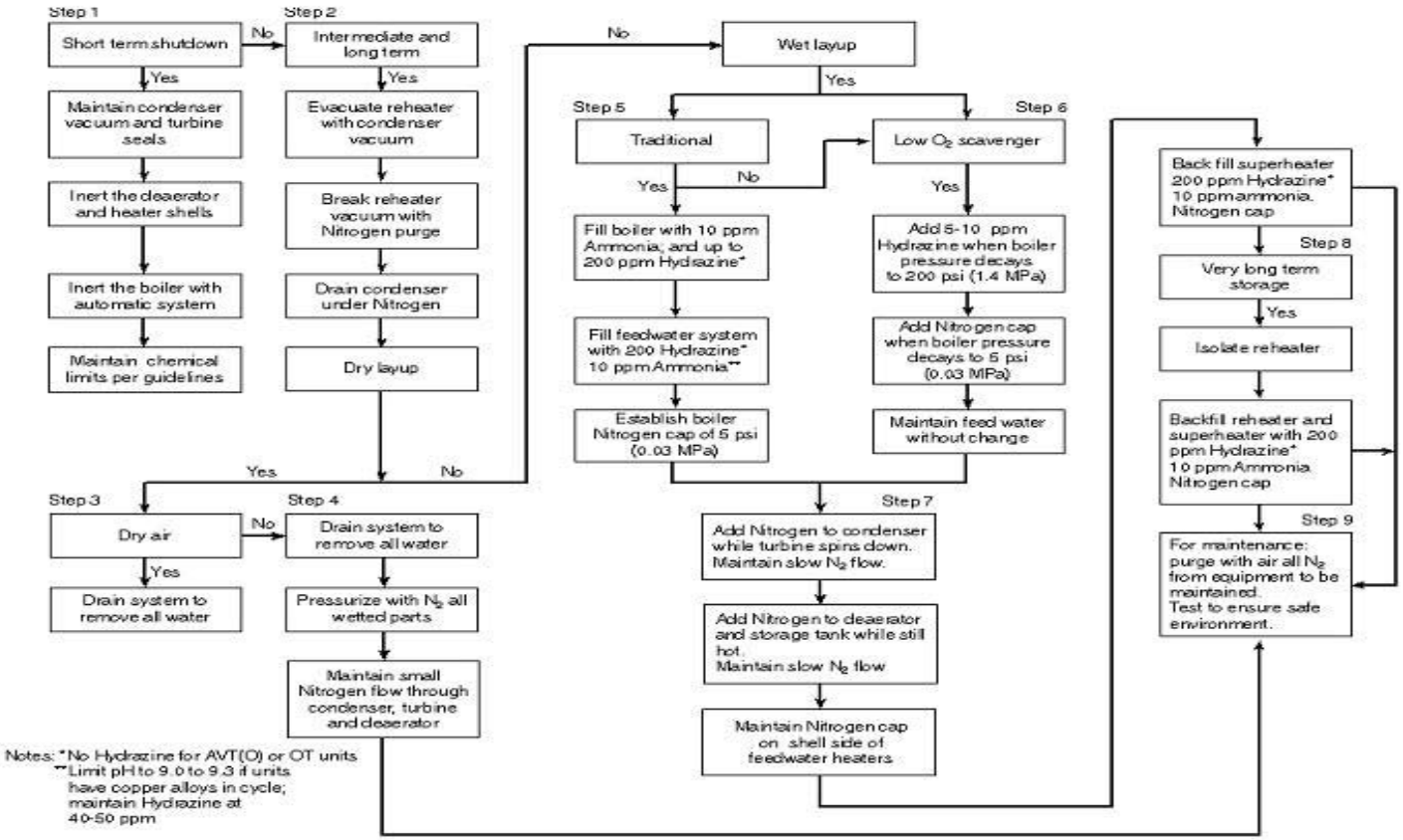

Fig. 9. Road Map for Developing Shutdown and Layup Procedures for Conventional Fossil Units[2]

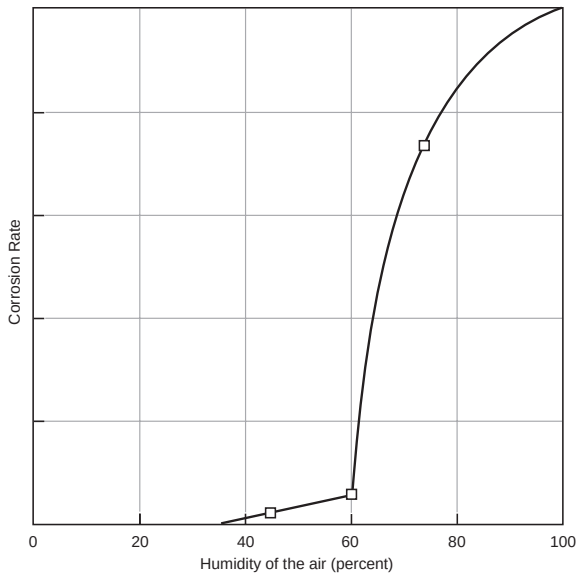

Fig. 10. Effect of Relative Humidity in Air on Corrosion Rate for Steel[6]

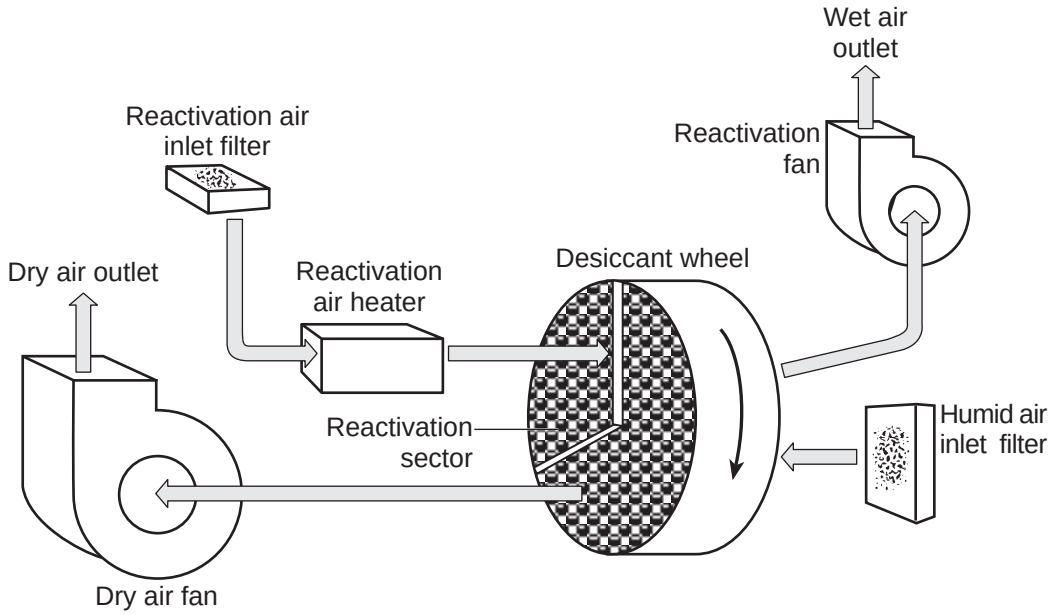

Fig. 11. Rotary Desiccant Dehumidifier used to Protect Fossil Plant Components[6,19]

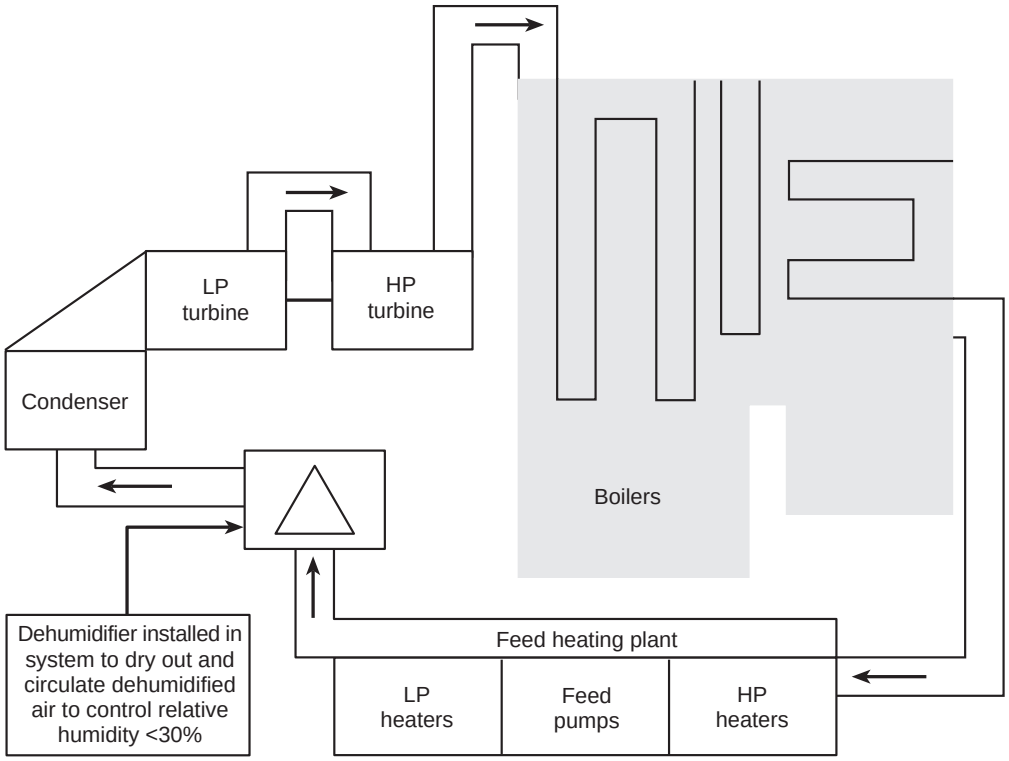

Fig. 12. Schematic of Dry Air Layup of Conventional Fossil Plant Steam-Water Cycle[6,20]

SESSION 11: NDE for Boiler and HRSG Tubing

Chairman: L. McQueen, OPG

LONG-RANGE GUIDED-WAVE INSPECTION OF REHEATER TUBE NETWORKS IN BOILER

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Field trials of the long-range guided-wave inspection technique were conducted, using the magnetostrictive sensor (MsS) technology, on horizontal reheater tube networks in a boiler during an outage. The trial results showed that comprehensive inspection of an entire length of reheater tube network between the outlet and inlet headers could be achieved without scaffolding from a few test locations using the technique. The achievable inspection range in one direction was approximately 30 feet for both 128-kHz torsional and 128-kHz longitudinal guided waves. Vertical spacers between the tubes in adjacent rows increased background noise and, thus, degraded inspection capability somewhat. In general, 90-degree bends and U-bends in the tube network showed no observable negative influence on inspection capability. Tight U-bends with bend radius of three tube diameters and less appeared to impair the wave propagation and, thus, prevent inspection of the area beyond. With proper tooling of the guided-wave probe that facilitates the placement of the probe on tubes in the rear row (from the accessible side of the tube bank), 100 percent volumetric examination of the entire reheater tube networks in a boiler without scaffolding or tube removal appears feasible.

INTRODUCTION

Boiler tube failure is the number-one cause of forced outages in power generating units, with corrosion, erosion, and fatigue cracking constituting the primary damage mechanisms. In order to prevent forced outages and the associated revenue loss and repair cost, boiler tubes are inspected during normally scheduled outages. Because of accessibility problems and the high cost of preparation (scaffolding and surface cleaning), inspections are typically performed only in limited and sampled areas—for example, ultrasonic measurements of wall thickness at selected tube locations. These limited inspection results are then used to assess the overall condition of the boiler and to determine subsequent maintenance actions. Boiler reliability could be significantly improved if the maintenance decision is based on comprehensive, rather than sampled, inspection results. Inspection techniques are needed that can provide comprehensive information on tube condition without requiring extensive preparation and long inspection time.

The long-range guided-wave inspection technique, an emerging technology already in use for inspection of piping in refineries and chemical plants, provides a 100-percent volumetric inspection of a long length of pipeline (typically more than 100 feet in one direction using 32-kHz torsional wave) for inside and outside surface corrosion/erosion defects and circumferential cracks, from a single measurement location [1–4]. This technique involves launching a short pulse of

guided waves in relatively low frequencies (up to a few hundred kHz) along the structure under inspection, and detecting signals reflected from geometric irregularities in the structure such as welds and defects in the pulse-echo mode, as schematically described in Figure 1. From the occurrence time of the defect signal and the signal amplitude, the axial location and severity of the defect are determined. This technique, therefore, has the potential to provide comprehensive condition information of the entire length of boiler tubing between the steam drum and the lower drum from one median elevation point of the boiler.

Recognizing the potential of the long-range guided-wave inspection technique for significantly improved boiler tube inspection, EPRI recently evaluated the technique's capability for inspecting reheater tube networks on laboratory mockups, made of new tubes and containing both 90- and 180-degree bends. The study, conducted by using the magnetostrictive sensor (MsS) technology, confirmed the technique's potential for inspecting entire lengths of tubing between the inlet and outlet headers [5]. Encouraged by the promising laboratory results, field trials of the long-range guided-wave inspection technique were conducted on horizontal reheater tube networks in a boiler during an outage to examine field applicability and limitations of the technique.

In this paper, the technical background of the guided-wave properties in boiler tubes and the MsS technology is briefly described first. Then, details of the field trials are given, including the configuration of horizontal reheater networks, test procedures, examples of test data, and findings.

TECHNICAL BACKGROUND

Guided-Wave Properties in Boiler Tubes

The tubes used for reheaters and superheaters are typically 1.75 to 2.5 inches in outside diameter (OD) and 0.17 to 0.44 inch in wall thickness. To illustrate the properties of guided-waves, the dispersion curves of longitudinal (L) and torsional (T) wave modes in various tube sizes are shown in Figures 2(a) and (b). These curves were calculated using general-purpose software called DISPERSE, developed at Imperial College in London [6]. As shown, L-waves are highly dispersive, and their properties vary significantly with tube size. T-waves, on the other hand, have much simpler properties. In particular, the T(0,1) wave is not dispersive and has a constant velocity (approximately 1.28×10^5 in./sec), independent of tube size. For long-range inspection purposes, the frequency is chosen from the region where the wave is not strongly dispersive.

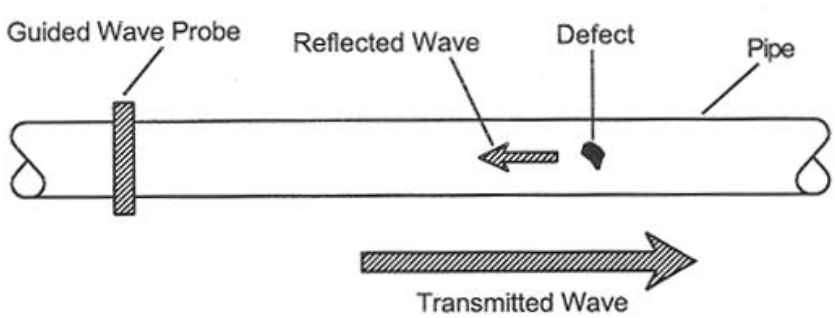
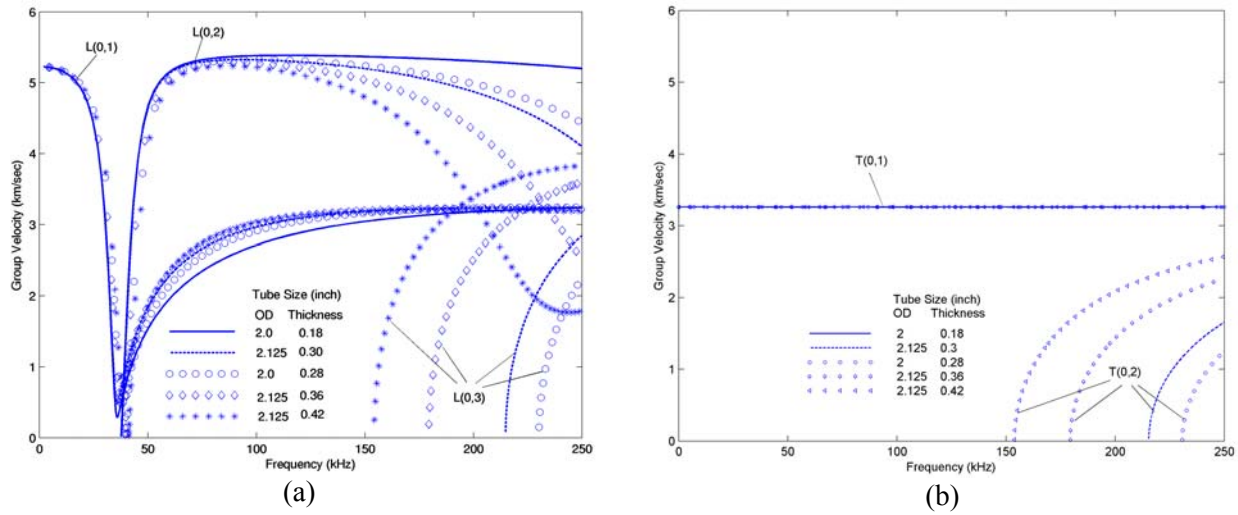


Figure 1. Long-range guided-wave inspection of piping



(a) (b)

Figure 2. Dispersion curves in boiler tubes of various diameter and wall thickness:
(a) L-wave and (b) T-wave

The MsS Technology

The MsS, developed and patented by SwRI [7], is a sensor that generates and detects guided waves electromagnetically in the material being tested. For wave generation, it relies on the magnetostrictive (or Joule) effect; the manifestation of a small change in the physical dimensions of ferromagnetic materials—on the order of several parts per million in carbon steel—caused by an externally applied magnetic field. For wave detection, it relies on the inverse-magnetostrictive (or Villari) effect; the change in the magnetic induction of ferromagnetic material caused by mechanical stress (or strain). Since the probe relies on the magnetostrictive effects, it is called a "magnetostrictive sensor (MsS)."

A schematic diagram of the MsS and associated instruments (Model MsSR 2020 [4]) for generation and detection of guided waves in pipe is illustrated in Figure 3. The MsS for piping uses encircling coils to apply the time-varying magnetic fields during guided-wave generation and to detect the magnetic induction changes during guided-wave detection.

The MsS is directly operable on structures made of ferrous materials such as carbon steel or alloyed steel. The MsS is also operable on structures made of nonferrous materials such as aluminum, by bonding a thin layer of ferromagnetic material (typically nickel) to the structure being tested and placing the MsS over the layer. In the latter case, the guided waves are generated in the ferromagnetic layer and coupled to the nonferrous structure. Detection is achieved through the reverse process.

For operation, the MsS requires that the ferromagnetic material under testing be in a magnetized state. This is achieved by applying a DC bias magnetic field to the material using either a permanent magnet, electromagnet, or residual magnetization induced in the material. The DC bias magnetization is necessary to enhance the transduction efficiency of the sensor (from electrical to mechanical and vice versa) and to make the frequencies of the electrical signals and guided waves the same.

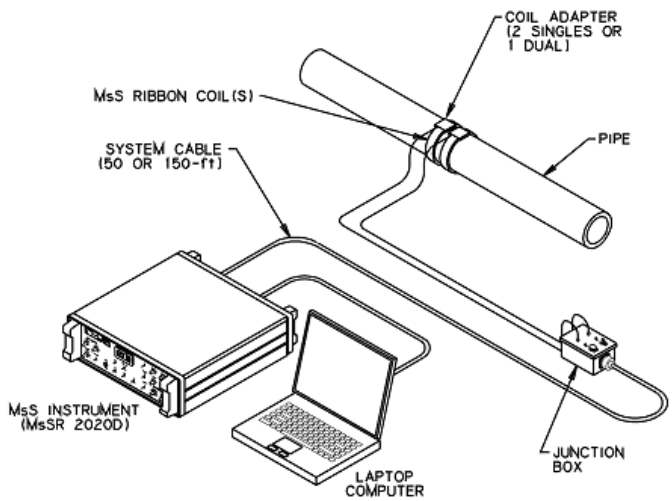


Figure 3. MsS system for piping inspection

The operating wave mode of the MsS is controlled by the relative alignment between the DC bias magnetic field and the time-varying magnetic field produced by the MsS. For L-wave modes in piping, the DC bias magnetic field should be applied along the lengthwise direction of the pipe. Permanent magnets are typically used to provide the required DC bias magnetic field for L-mode. For T-wave modes in piping, the DC bias magnetic field should be applied along the circumferential direction of the pipe. The circumferential DC bias field required for T-mode operation can be provided by applying a high DC electric current along the lengthwise direction of the pipe. Due to safety reasons, however, the high DC electric current approach is less practical. The thin-ferromagnetic-strip approach is, therefore, almost exclusively used in practice where, before or after attaching the strip around the pipe circumference, the strip is momentarily magnetized along its lengthwise direction. The resulting residual magnetization induced in the strip provides the circumferential DC bias magnetic field required for T-mode.

Single MsS generates and detects the guided waves propagating in both directions. In practical inspection applications, guided-wave generation and detection are controlled to work primarily in one direction so that the area of the structure on either side of the sensor can be separately inspected. The wave direction control is achieved by employing two sensors, as illustrated in Figure 3, and the phased-array principle in the MsS instrument.

FIELD TRIALS ON REHEATER TUBES IN BOILER

Reheater Tube Network Configuration

The field trials described in this paper were conducted at the O. W. Sommers Power Plant, owned by City Public Service of San Antonio, Texas. It is a gas-fired plant with a generation capacity of 400 MW and has been in operation since 1972.

The MsS guided-wave testing was conducted on horizontal reheater tubes in one of the boilers at the plant. A schematic diagram of the horizontal reheater tube network is shown in Figure 4. The reheater tube banks consisted of five rows of tube lines between the outlet and inlet headers. The

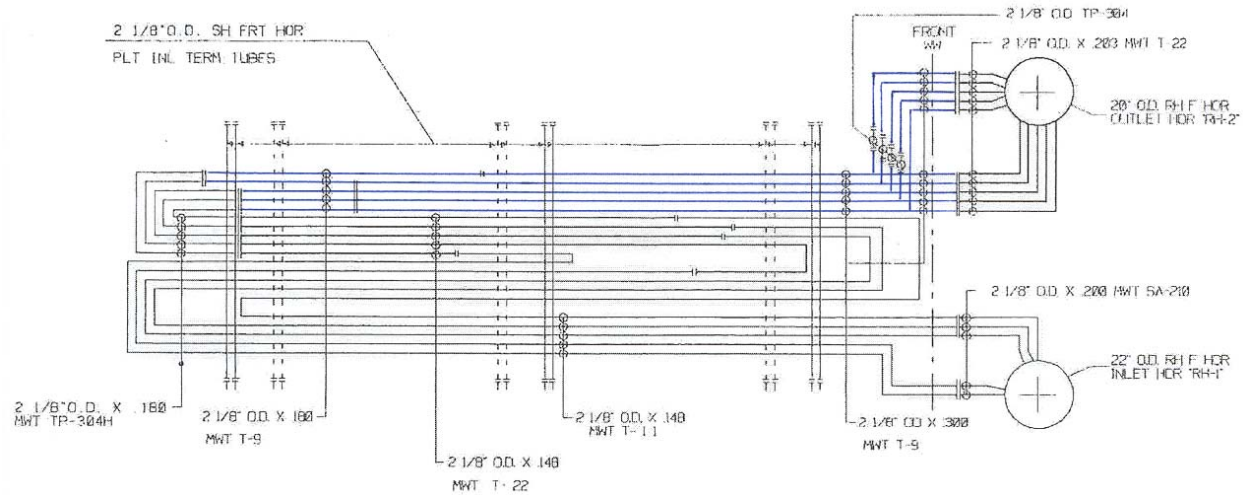


Figure 4. Schematic diagram of the horizontal reheater tube network

OD of the tube was 2-1/8 inches. The overall horizontal length of the reheater tube was approximately 40 feet. Each tube line was made of five different materials (SA-210 A-1, SA-213 T-11, SA-213 T-22, SA-213 T-9, and SA-213 TP-304H), with thicknesses ranging from 0.148 to 0.300 inch. Each line also contained three U-bends and two or more 90-degree bends. The total length of each tube line between the inlet and the outlet headers was approximately 130 feet. The reheater tubes were fastened to hangers by means of welded brackets, as shown in Figure 5(a), and the tubes in adjacent rows were kept apart by means of vertical spacers welded between them, as shown in Figure 5(b).

Test Instrument, Parameters, and Procedures

The MsS system illustrated in Figure 3 was used. The MsS instrument was set up outside the boiler near a manway on the 7th floor of the unit, and the MsS coils installed on the tubes to be tested were connected to the instrument via a 100-foot-long system cable. Both 128-kHz T(0,1)-wave and 128-kHz L(0,2)-wave were used in this trial.

(a) (b)

Figure 5. Photo of reheater tubes: (a) at hangers and (b) at a spacer area

For T-wave operation, the tube surface at a selected test location was brushed off and loose particles were wiped off with a paper towel. A 0.005-inch × 1-inch nickel strip was cut to the right length and magnetized along its lengthwise direction. Then the strip was adhesively bonded around the tube using 5-minute epoxy. The MsS ribbon coils were then placed around the tube over the nickel strip, as shown in Figure 6(a).

For L-wave operation, the MsS ribbon coils were placed around the tube. Then two relatively small size (1-inch × 2-1/8-inch × 6-inch), U-shaped, permanent magnetic circuits were placed approximately 180 degrees apart on the tube across the MsS ribbon coils, as shown in Figure 6(b). The magnetic poles of the two circuits should be oriented the same way.

After the placement of the MsS coils, the right- and left-hand sides of the tube from the sensor were examined separately using the wave direction control in the MsS instrument.

Since the L-wave operation did not involve the adhesive bonding process, it was easier and quicker to conduct than the T-wave operation for reheater tube inspection. In areas where the spacing between the tubes was large enough to put an arm through, the MsS coils could be placed on a tube even in the farthest (fifth) row from the accessible side of the tube bank. Most of the testing was performed, however, on the easily accessible front row tubes.

Test Results and Findings

Examples of the test data are shown in Figures 7 through 10. They were all obtained from the tubes in the front row and, in each figure, data from two different tubes are given. The data in Figure 7 are for 128-kHz T-wave obtained from a test location approximately 9 feet from the outlet header. The data in Figures 8 through 10 are for 128-kHz L-wave that were obtained from a test location near the outlet header, near the first U-bend from the outlet, and near the inlet header, respectively.

(a) (b)

Figure 6. Photos of MsS ribbon coils placed on a reheater tube:
(a) for T-wave and (b) for L-wave

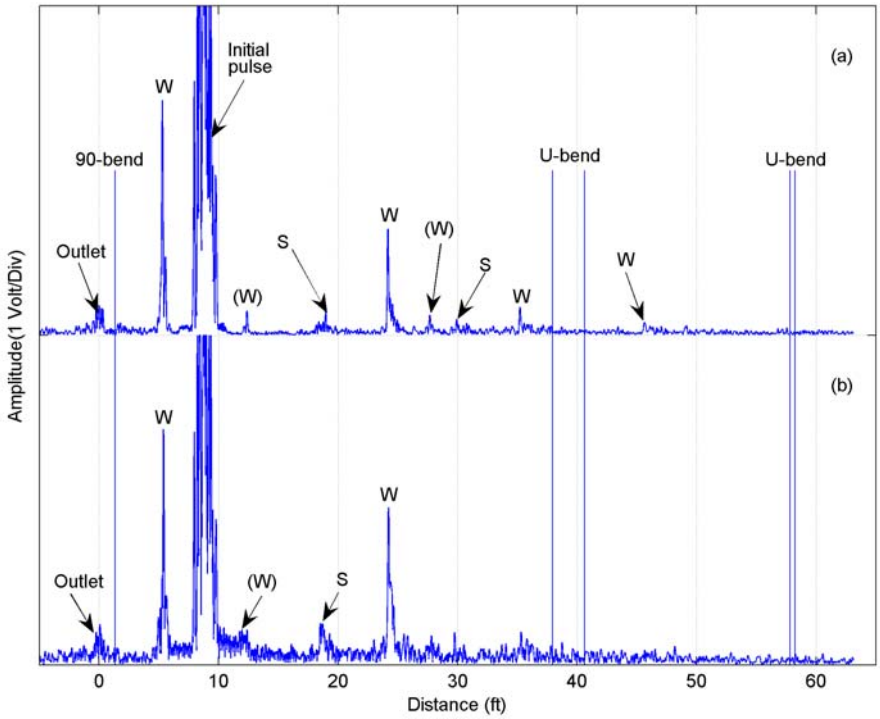


Figure 7. 128-kHz T-wave data taken from a location near the outlet header

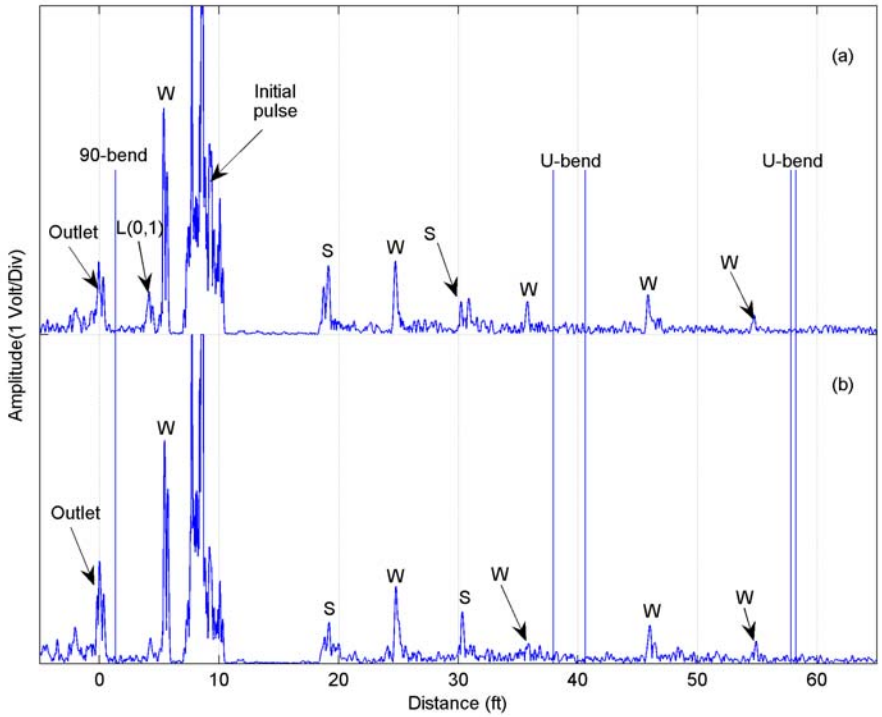


Figure 8. 128-kHz L-wave data taken from a location near the outlet header

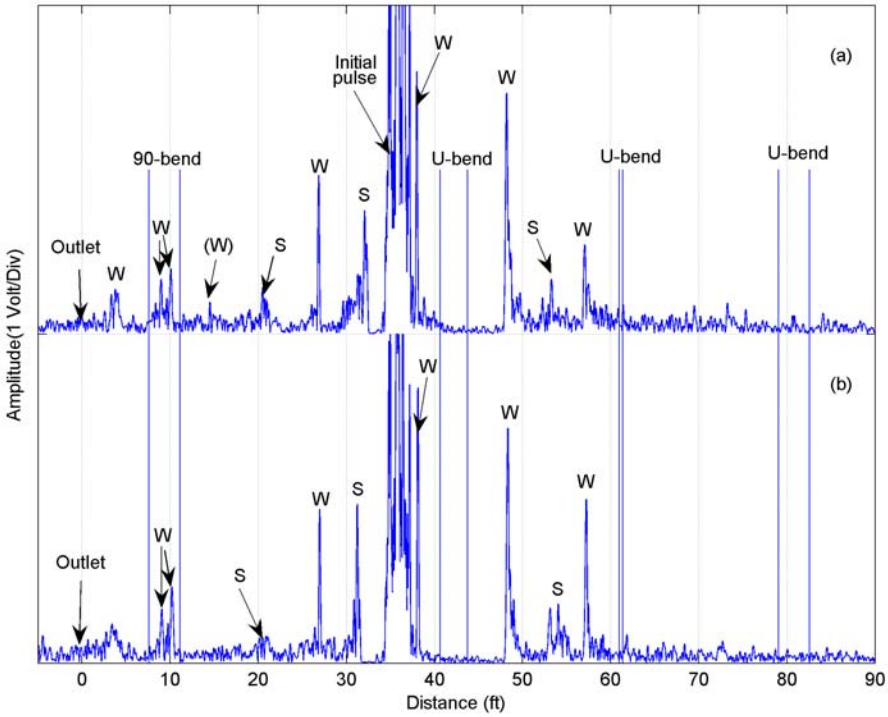


Figure 9. 128-kHz L-wave data taken from a location near the first U-bend from the outlet header

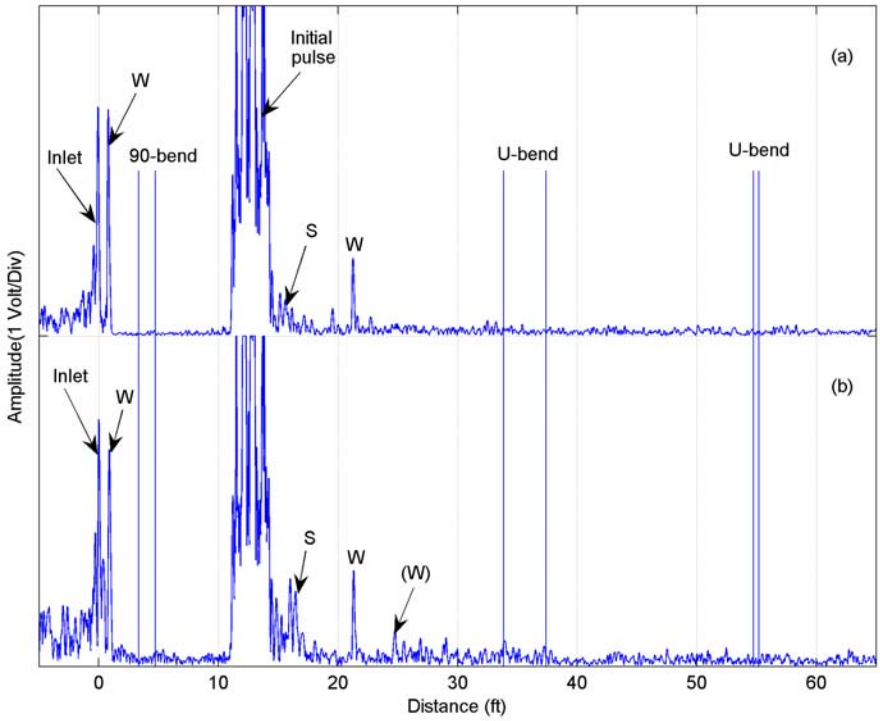


Figure 10. 128-kHz L-wave data taken from a location near the inlet header

In the figures, “W” indicates a signal from a weld and “S” from a vertical spacer between the tubes in adjacent rows. The locations of 90-degree and U-bends in the reheater tube network are indicated in the plot. Signals caused by imperfect direction control and multiple reflections are indicated in parentheses [for example, (W)]. Welded brackets at the hangers did not produce measurable signals and, therefore, are not indicated in the figures. Because the configuration of all tube networks was more or less the same, the data obtained from different tubes in a given test location were very similar to each other, as shown in Figures 7 through 10.

Referring to the 128-kHz T-wave data in Figure 7(a), a weld that was approximately 46 feet away from the sensor location was detectable. Assuming that a weld corresponds to a 20-percent reflector, the inspection range for detecting a 5-percent defect was estimated to be approximately 30 feet. The attenuation coefficient of the 128-kHz T-wave was about 0.25 to 0.35 dB/ft (for one-way trip distance). Signals from the vertical spacers were about one-fourth the weld signal amplitude. There was an increase in the background noise level before and after the first S-signal, indicating that vertical spacers degrade the inspection capability. The increased background noise level after the first S-signal (in this case, about a factor of two) was believed to be due to mode-converted signals at the vertical spacer. On the other hand, the U- and 90-degree bends (except for tight U-bends) produced no observable increase in the background noise level.

The data in Figure 7(b) were worse than the data in Figure 7(a), not because the tube was in poorer condition but because MsS performance was lower, mostly likely due to poorer bonding of the nickel strip.

The 128-kHz L-wave data shown in Figure 8 were obtained from the same tubes shown in Figure 7. The attenuation coefficient of the 128-kHz L-wave was also about 0.25 to 0.35 dB/ft. The inspection range for detecting a 5-percent defect was also estimated to be approximately 30 feet. The L-wave signal from S was comparable to the weld signal in amplitude, and the increase in background noise before and after S was greater than the T-wave. The degradation in inspection capability caused by vertical spacers was, therefore, greater for the L-wave. When an L(0,2) wave mode interacts with a weld, it also produces an L(0,1) mode. The signal indicated as L(0,1) after the 90-degree bend was caused at the nearby weld.

The L-wave data in Figures 9 and 10 showed similar behavior to that observed in the data in Figure 8. Additionally, in Figure 9, signals fell to noise level after the tight U-bend (at approximately 61 feet), indicating that the tight U-bends (bend radius estimated to be three tube diameters or less) disrupt wave propagation and prevent inspection of the area beyond.

During the field trials, no areas with significant defect indications were found. To facilitate the field inspection of reheater tubes, development of special guided-wave probes for this application is necessary. Also, to improve data interpretation and quantify the detected signals, suitable calibration procedures are needed.

CONCLUSIONS

Based on the findings and lessons learned from these limited field trials, we conclude the following:

(1) The long-range guided-wave inspection technique has potential for comprehensive inspection of reheater boiler tube networks in the field.

(2) The achievable inspection range in one direction was approximately 30 feet for both 128-kHz T-waves and 128-kHz L-waves.

(3) In general, suitable locations for MsS installation could be found along the length of any tube network. Therefore, with proper tooling, all tube networks could be inspected from the accessible side of the tube bank without requiring scaffolding and tube removal.

(4) Vertical spacers increased background noise level and, thus degraded inspection capability. The degradation was greater for the L-waves than for the T-waves.

(5) Except for tight U-bends, other 90-degree bends and U-bends in the tube networks did not show any observable negative influence on wave propagation. Tight U-bends (bend radius estimated to be three tube diameters or less) appeared to impair wave propagation and, thus, prevented inspection of the area beyond.

(6) The entire length of the tube network between the inlet and outlet headers could be examined from two to three test locations, depending on the number of tight U-bends in the network.

For eventual field implementation of the MsS long-range guided-wave technique for reheater boiler tube inspections, the following actions are recommended:

(1) Develop a customized MsS guided-wave probe that facilitates tests on tubes in back rows, including the farthest row from the accessible side of the tube bank.

(2) Add a calibration procedure to improve data interpretation.

(3) Conduct additional field trials to optimize test parameters (T-wave vs. L-wave, wave frequency) and procedures for reheater tube inspection and to determine the applicable range and defect detection sensitivity achievable using the guided-wave inspection technique.

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DETECTION AND QUANTIFICATION OF DAMAGE IN STUB TUBES USING ULTRASONIC PHASED ARRAYS

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Abstract

Socket welds joining stub tubes to high temperature headers fail at a number of locations and due to a number of mechanisms. Many failures initiate at exposed surfaces, where they are relatively easy to detect using conventional magnetic particle and liquid dye penetrant inspection methods. However, cracks can also initiate internally, at the weld root due to high temperature creep, where they can grow undetected to failure unless non-conventional inspection approaches are utilized. Properly designed and implemented ultrasonic inspection techniques have proven effective in detecting these subsurface cracks and, in fact, such techniques have been the only proven means of defining internal service damage prior to failure. Unfortunately, initial inspection approaches have been typically very sensitive to initiation but less effective in defining growth and in distinguishing between minor damage and significant damage. Consequently, results have been conservative, often leading to corrective action well before necessary based on actual flaw size.

Ultrasonic inspection techniques available for this inspection have now evolved from qualitative, to semi-quantitative, to fully quantitative. This evolution has involved advancements from first using broad beams, to cylindrically focused, to fully focused and steerable beams using linear phased arrays with lateral focusing capabilities. The use of laterally focused linear phased arrays now represents the state of the art for stub tube socket weld inspection and provides the means to quantify damage and perform remedial repairs only as necessitated by growth rates and planned outage schedules.

Introduction

Stub tube to header socket welds in conventional fossil-fueled power plants have long been recognized as a location susceptible to cracking and failure. The damage may occur in the header-side or tube-side heat-affected zone or in the weld metal. The damage may also initiate on the external surface or sub-surface at the weld root. The susceptibility and exact damage morphology is dictated by the specific stress and relative properties of the header, stub tube, and weld metal. In addition, for convention plants the low alloy systems used provide a tolerance to rapid crack initiation and growth and access to the stub tube welds is in the majority of cases reasonable; thus, detection and quantification

of damage in most stub tube to header welds can be managed through the implementation of rather coarse, surface nondestructive testing techniques. However, increasingly outage intervals are being extended and as a consequence more quantitative NDE techniques are being used even for conventional plants particularly for the subsurface of weld root initiated cracking. Over the past 10 years this has lead to the development and implementation of enhanced focused and linear array ultrasonic techniques for the detection, quantification, and trending of subsurface or weld root cracking.

Stub tube welds in most high temperature sections of HRSG's are significantly different than conventional plants. Specifically, these welds are most often not the more damage tolerant low alloy steels (e.g., 2.25CR-1MO) but are the less marginal T91 which are reported to be less tolerate to defects from the fabrication process (fit-up, root condition, percent penetration, heat-treatment, etc.). The susceptibility to damage can be exacerbated in those instances where the stub tube weld represents a dissimilar metal weld between low alloy and 9CR steels. Access to the stub tube welds can be very limited due to header spacing within a module and the available length of unfinned tube at the weld. Thus, deploying conventional surface NDE techniques may be inconvenient and more importantly ineffective in providing the earliest detection and quantification of damage. However, the attributes of the enhanced linear array ultrasonic techniques offer significant advantages in these applications as it did for conventional plant stub tube welds.

Conventional Plant Stub Tube Weld Testing

As high temperature headers in fossil-fuelled plants continue to accumulate additional operating hours and cycles damage begins to occur to an increasing number of header subcomponents; including but not limited to body girth welds, ligaments, outlet tees and nozzles, supports, drain lines and stub tube-to-header welds. For the latter, external damage can occur in several different locations based on a number of variables. The most frequently occurring external damage modes are shown in Figure 1. Since these locations are reasonably accessible and the damage on the external surface, conventional magnetic particle and liquid penetrant inspection methods are typically used for the detection of cracking. In addition, metallurgical replication is often used as a complementary inspection to identify or confirm the actual damage mechanism and material contribution.

The more difficult stub tube weld damage to deal with has been cracking at the J-Prep Weld Root, examples of which are provided in Figure 2. This damage is characterized by subsurface crack growth along the fusion line or heat-affected zone. A number of explanations have been given for damage development that cite the stand-off of the tube end in the counterbored hole and oxidation in the gap as a primary contributors; however, initiation is also exacerbated by weld defects (i.e., slag or incomplete penetration) and growth can be accelerated with fatigue interactions.

Clearly, subsurface cracking can go undetected with only surface examination techniques (PT, MT) until failure occurs, as shown by examples in Figure 2. Therefore, SI

developed and routinely applies a focused ultrasonic technique for the detection and semi-quantitative assessment of weld cracking. A schematic drawing of this technique is provided in Figure 3. The basic approach utilizes ultrasonic shear waves (S-waves), introduced from the outer surface of the tube and directed axially down the tube, toward and into the weld. Because the damage, if subsurface and originating at the weld root typically propagates along the header side fusion line of the weld, the ultrasonic beam is directed such that it reflects from the ID of the tube, through the weld, and at the header side fusion line. The actual refracted angle of the ultrasonic beam must be carefully designed to accommodate the geometry and deliver the beam at the fusion line. Ideally, the beam will arrive at the fusion line at normal incidence such that it is reflected directly back along the same path to the transducer.

For some tube sizes, the inspection can be performed on the second leg as the ultrasonic angle beam reflects from the tube bore back into the weld, as shown in Figure 4, top. However, most often the best inspection approach is a compromise between the ideal beam angle, i.e., the angle that introduces the beam perpendicular to the fusion line, and the achievable angle. A better compromise can typically be achieved by utilizing the fourth leg of the reflected beam, as shown in Figure 4, bottom. Typically, the transducer wedge needed to produce the appropriate refracted angles is relatively long, and the wedge therefore holds the transducer too far away from the weld to introduce the beam at the optimum detection angle. By moving to the fourth leg, a more appropriate refracted angle can be utilized.

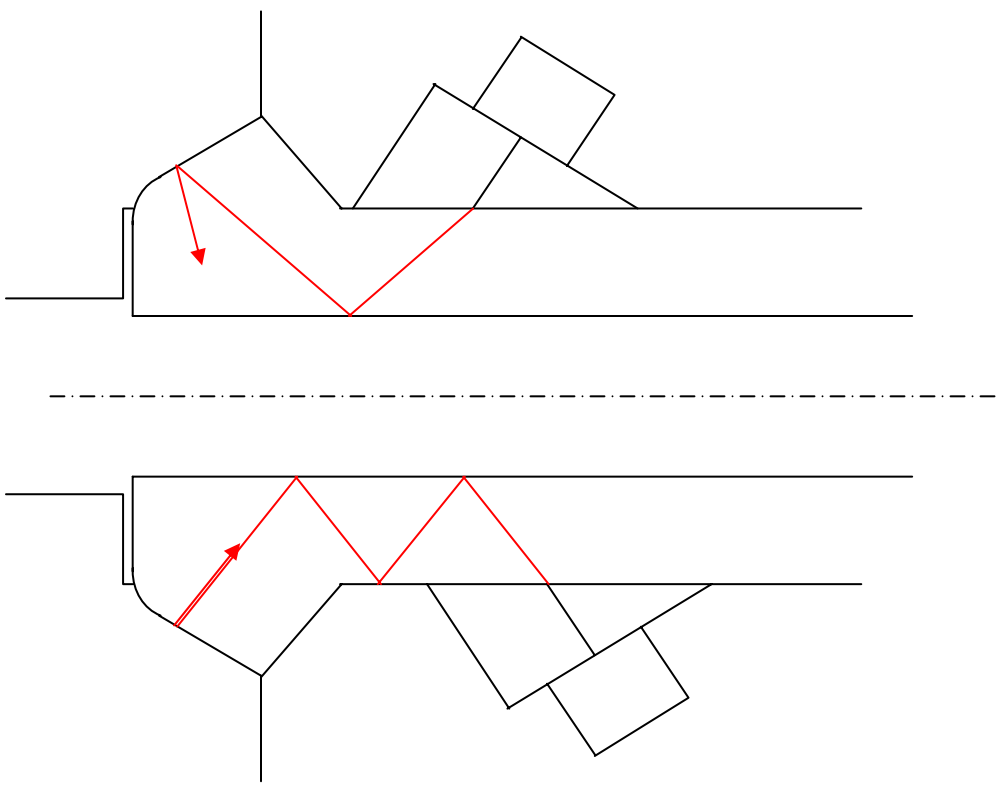


Figure 4. Second Leg Inspection (Top) and Fourth Leg Inspection (Bottom).

It is also necessary to focus the ultrasonic beam at the weld fusion line interface if any level of results quantification is desired. When an ultrasonic beam reflects from a flat surface, the general shape of the sound field remains effectively unaltered. The beam changes direction, but otherwise it remains the same before and after the reflection. However, when the reflection is from a contoured surface, the shape of the surface not only changes the direction of propagation, but it also changes the shape and characteristics of the field. Figure 5 shows three possibilities for the more simple cases in which an initially divergent beam, with its axis normal to the surface, reflects from either the ID or OD of a cylindrical interface. For the divergent beam reflecting from the ID, as shown in the top two frames of Figure 5, the reflected beam can be either more divergent, less divergent, or even focused, depending on the location of the beam source relative to the center of curvature of the cylinder. For a divergent beam reflecting from the OD, as shown in the bottom frame of Figure 5, the reflected beam will always be more divergent.

Given these reflection possibilities, the characteristics of the beam can be significantly affected when the beam is directed in multiple reflection paths along the length of a cylindrical shape. This is particularly true in relatively small diameter components, such as the subject tubes, and in a fourth leg inspection where the effects are magnified by the small diameters involved and the additional reflections involved in both the transmisision and reflection paths.

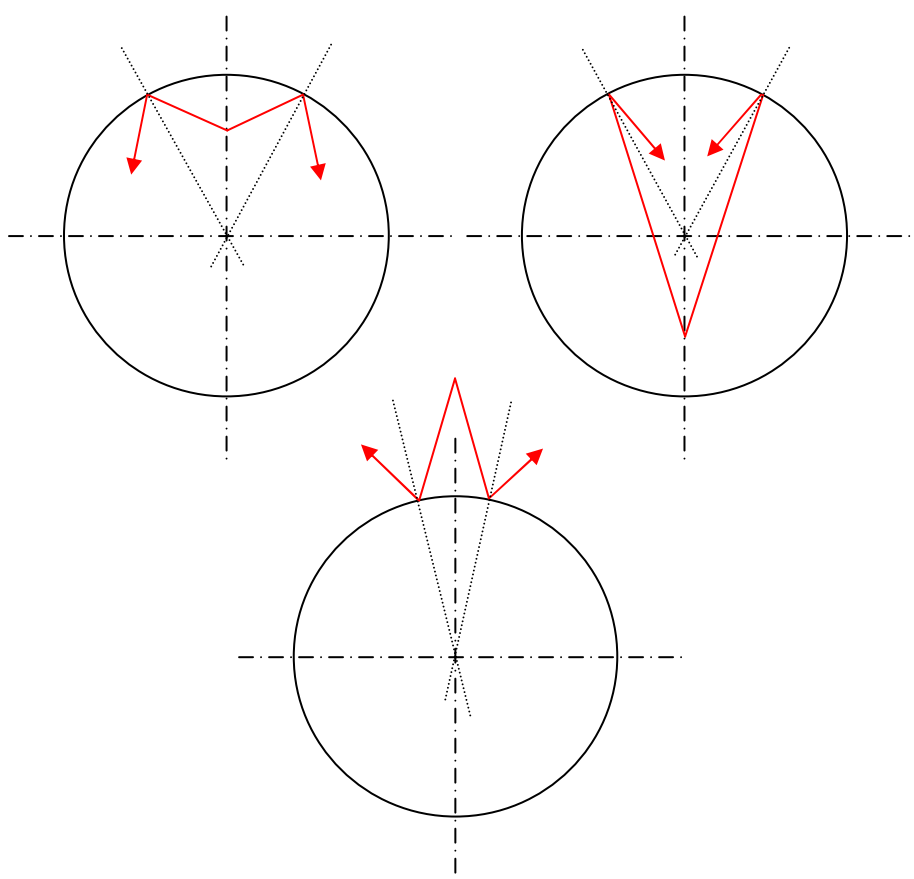


Figure 5. Reflection from Concave (Top) and Convex (Bottom) Surfaces.

Figure 6 provides a computer simulation of a conventional, broad ultrasonic beam in a tube simulation of the socket weld inspection. In this case, which depicts a fourth leg inspection, the beam has spread fully around the circumference of the weld by the time it has propagated that far and undergone the multiple reflections through the tube. On the return path, any reflection continues to spread in the same manner, resulting in low sensitivity. In addition, the broad beam approach lacks any capacity for quantifying the results because of the uncertainty associated with the source of any reflection.

Figure 7 provides a similar simulation of a focused beam. In this simulation, the beam is focused in both directions, circumferential and radial, such that a relatively small beam spot impinges on the fusion line interface. The computer simulation demonstrates clearly the advantages of the focused beam. The energy of the beam at the fusion line is maintained in a tight focal spot, which results in high sensitivity to relatively small fusion line flaws. In addition, and more importantly, the improved resolution of the relatively small spot size enables characterization of damage and quantification of the results to a degree not even approachable with a broad beam.

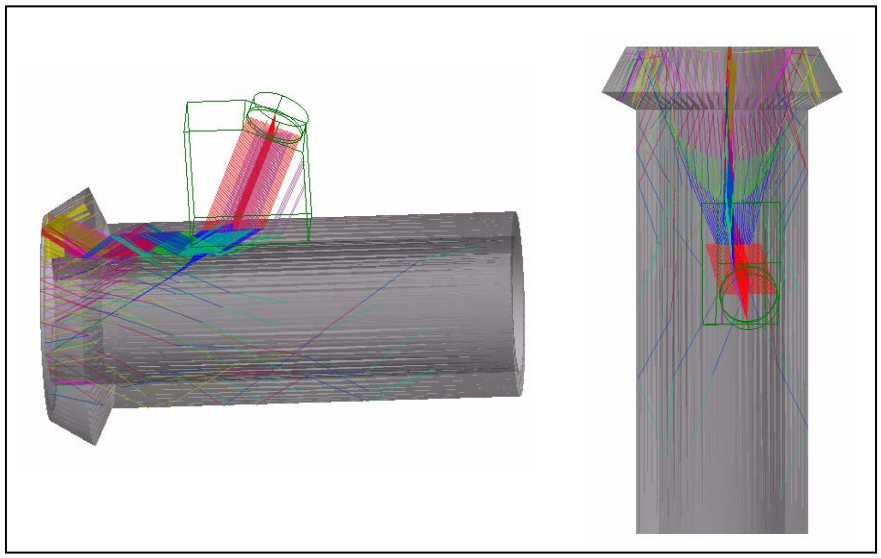


Figure 6. Conventional, Broad Ultrasonic Beam in Hollow Cylinder.

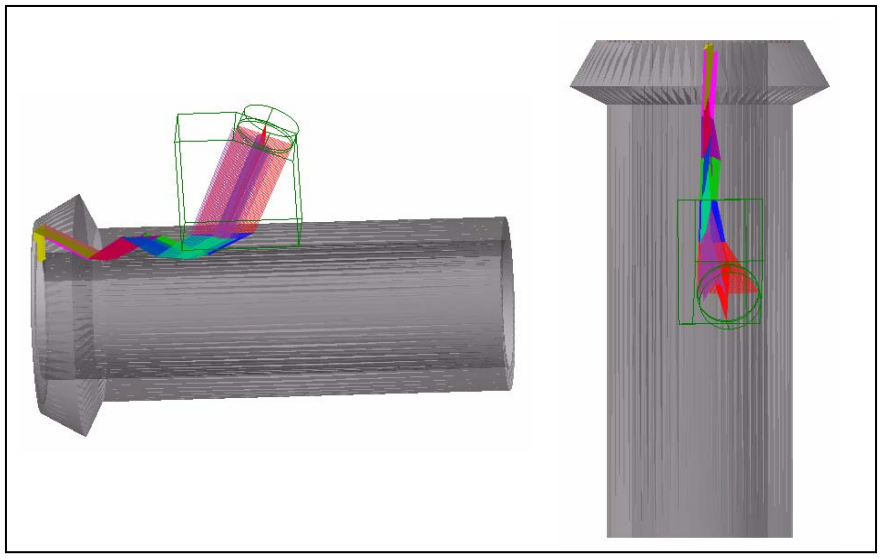


Figure 7. Focused Ultrasonic Beam in Hollow Cylinder.

Unfortunately, until recently it was not practical to achieve the level of focusing depicted in the computer simulation shown in Figure 7. To do so requires the use of complex mathematical models and algorithms with which to determine the optics required to properly focus the beam in two dimensions. In addition, it requires the ability to quickly make compound curvature focusing lenses to simultaneously bring the beam into focus in the radial and circumferential directions. Moreover, it requires a-priori, detailed dimensional information with which to define the optimum focusing lens and have it machined and available at the time of the inspection. Typically, this information is not readily available. As a result, a compromise solution has been utilized until recently. In this approach, spherical focusing has been achieved using simple solutions based on flat plate conditions. In such case, the beam is accurately focused in the radial direction, because this direction is accurately simulated using flat plate considerations. However, while it is focused in the circumferential direction as well, the focus is not optimum because it does not take into consideration the curvature effects on beam shape upon each reflection along the length of the tube. This approach, however, has served to provide a significant improvement over broad-beam capabilities and has enabled a semi-quantitative assessment of fusion line damage.

The semi-quantitative assessment consists of assigning a Level to each detected reflector that is based on an amplitude response. Specifically, the levels are established to be:

- Level 1 ⇨ 30% to 60% of the Reference Amplitude
- Level 2 ⇨ 60% to 90% of the Reference Amplitude
- Level 3 ⇨ >90% of the Reference Amplitude

This assessment is performed independently for each quadrant of the weld, where the maximum damage level is recorded for each quadrant around the circumference of the

weld as shown in Figure 8. Next, an overall assessment of the damage in the weld is made by merely summing the damage rating for the four quadrants and the weld damage assessments are plotted on a damage map for the header, also shown in Figure 8. This mapping system reveals damage distributions, which are then used for trending, to target repairs, and to optimize inspection efforts. It should also be noted that the type of damage that typically leads to weld root cracking is predominately creep and therefore temperature dependant. Thus, oxide testing of the tube stubs is often used to develop temperature profiles to aid in the assessment of the stub tube damage and as an integral part of a strategic socket weld/stub tube management program.

There are still drivers (such as increased duration between boiler outages) to develop and implement more quantitative inspection approaches to replace the semi-quantitative approach previously discussed. As with any ultrasonic inspection, the response received from any particular reflector is a function of a combination of the beam characteristics and the flaw characteristics and the way the two interact to produce the response. Consequently, one means of improving the ability to quantify damage is to produce more representative reflectors in accurate mockups of the actual tube and weld geometries. Previously, mockups consisted either of welded samples with intentional flaws welded in, or machined simulations with EDM notches, side drilled holes, and/or flat bottom holes. In the former, the geometry could be simulated accurately, but in the final accounting, any flaw that was implanted had a relatively high uncertainty associated with its actual size, shape, orientation, etc. In the latter, accurate reflector shapes could be inserted in relatively accurate geometric simulations of the tube and weld, but the flaws cannot be introduced in such a way to accurately simulate the compound curvature of a crack originating at the weld root and following the header side fusion line. One improvement has been the design of more representative calibration blocks, an example is shown in Figure 9, to better understand the UT behavior and sizing capabilities of the system. These blocks are made using EDM electrodes that are shaped to exactly duplicate the compound curvature of a crack growing along the header side fusion line of the weld from the weld root. These blocks, for the first time, provide simulated reflectors that accurately represent the flaws of interest in an accurate simulation of the component geometry.

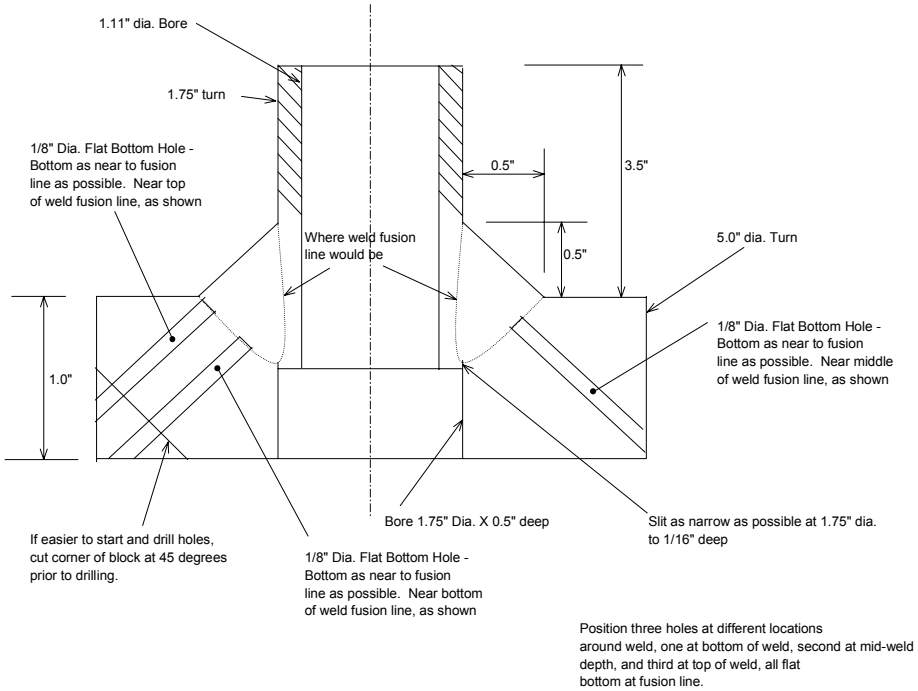


Figure 9. Accurate Block with Accurate EDM Simulations of Crack Shape and Location.

Another improvement that was previously not available but which can now be incorporated into an improved inspection approach involves the use of a linear array ultrasonic system with which to sweep a range of beam angles rather than using a single inspection angle. Figure 10 shows a setup in which the fixed beam angle is selected on the basis of detecting the shallow crack at the weld root. This typically requires a relatively high inspection angle and is the normal setup because the root is the initiation site and is therefore more likely to have a flaw. However, when the transducer is scanned away from the weld to scan the beam up the fusion line, the angle of the beam on the fusion line is far removed from normal incidence; consequently, sensitivity along much of the fusion line is very low. While this figure show the setup as a second leg inspection, the same is true of the fourth leg setup when testing relatively thin tubes.

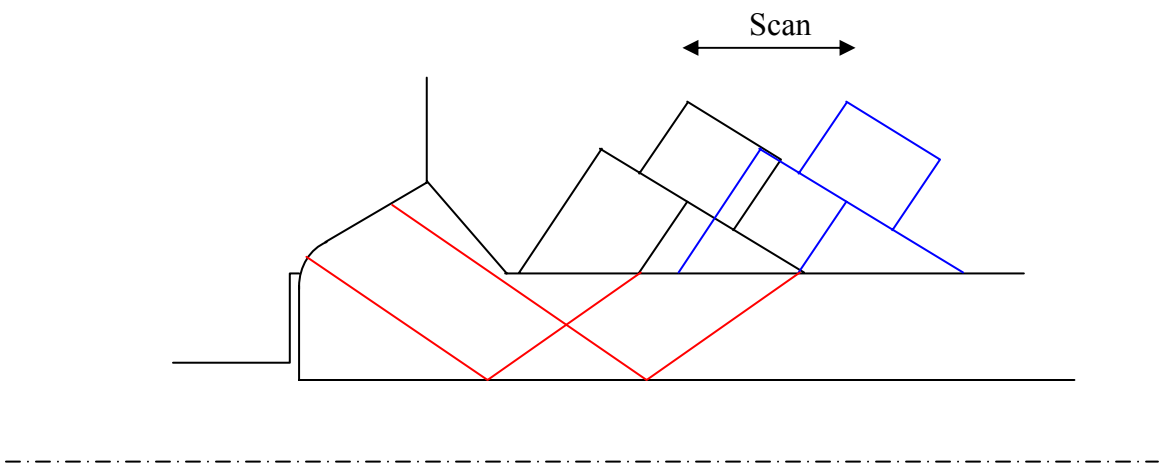


Figure 10. Fixed Beam Angle Optimized for Root Detection.

Figure 11 shows another fixed angle setup that is more appropriate for detection of damage along the fusion line away from the root. Improved sensitivity to this type of flaw is achieved by introducing a beam that is more normal to the fusion line such that the reflection returns along the same path to the transducer. Here, however, the transducer cannot be scanned sufficiently to interrogate the weld root. Consequently, as can easily be seen in these figures, the inspection most often involves a beam angle that is only effective over a limited portion of the fusion line or a compromise that is more generally effective along a greater portion of the fusion line, but not optimized for any single location.

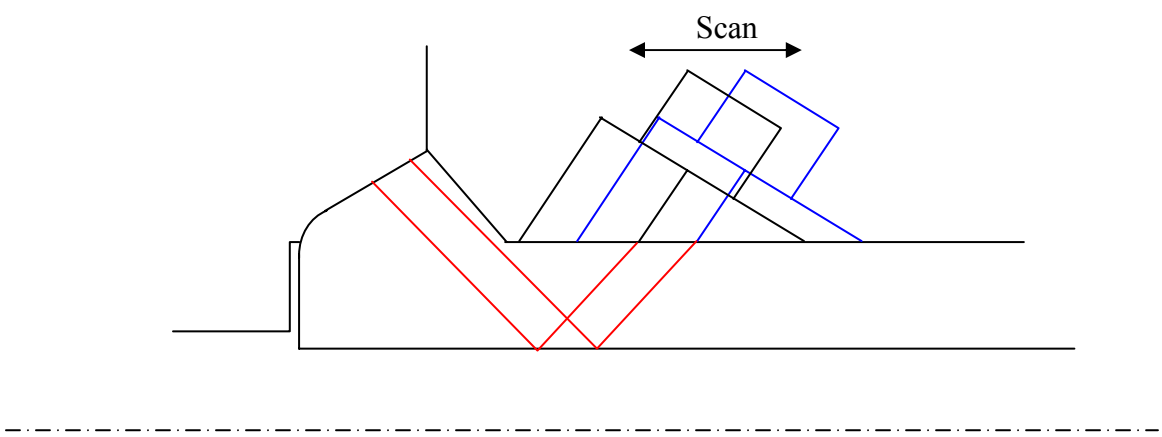


Figure 11. Fixed Beam Angle Optimized for Fixed Angle Portion of Fusion Line.

Without going into great detail on the operation of a linear phased array ultrasonic inspection system, suffice it to say that it combines a multi-element array transducer with an electronic subsystem that provides the capability to pulse each element independently and at very precise phasing intervals. By phasing the pulses applied to the various elements in the proper sequence and at the appropriate phasing delays, the beam can be steered to a precise angle other than that defined by the refracting wedge. By then varying the sequence and phasing appropriately on successive pulse sequences, a series of beam angles can be generated sequentially. In other word, the array enables the operator to sweep the beam through an angular range, whereas the conventional ultrasonic approach involves a single angle that is controlled purely by the refracting wedge. Figure 12 shows a swept beam in the stub tube socket weld application. Clearly, it is easy to see that this permits comprehensive coverage of the entire fusion line at angles that are more appropriate for detection of flaws along the entirety of the fusion line, fully from the weld root to the OD of the header.

An equally important means of improving the ability to quantify damage is to produce a beam that has accurately defined and known characteristics, i.e., by addressing the second part of the flaw/beam interaction. In the complex geometry of the tube and weld, the best means of optimizing the beam characteristics is to produce a beam that is well focused in both the radial and circumferential directions. However, as discussed above, this is not easily achieved using only optical solutions (i.e., lenses), because each lens is appropriate for a given combination of all factors influencing the beam in both the radial and circumferential directions. Clearly, there are too many combinations to effectively carry the appropriate inventory of equipment to match all encountered circumstances. Fortunately, the linear array described above can be utilized to achieve focus in the radial direction in addition to the ability to steer the beam through a range of appropriate beam angles. That is, the beam can be simultaneously steered over the appropriate angular range to cover the full fusion line, while simultaneously focusing the beam electronically at the appropriate depth for optimum detection.

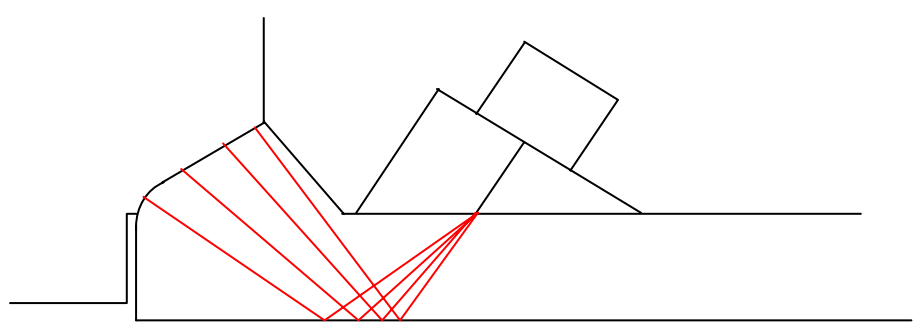


Figure 12. Linear Phased Array Swept Beam Inspection Approach.

When using a linear array, the beam characteristics are controlled electronically only in the plane of beam steering, in this case in the radial/axial plane. In the circumferential direction, the beam characteristics remain the same as those produced by a conventional

probe unless altered in some other way. However, by limiting the focusing requirements to a single direction (i.e., the linear array takes care of the radial/axial focusing, so only the circumferential direction remains broad-beam), the additional lateral focus can be accomplished using simple cylindrical focusing lenses. Because lenses need not address any number of combinations of radial/axial and circumferential focusing combinations, a limited number of lenses can be made to cover most any situation encountered. Moreover, this is possible because lenses having a single curvature axis are simple to manufacture.

Through this approach, it is possible to achieve the dual directional focus like the simulation shown in Figure 7. Simultaneously, the beam can be steered through a range of refracted angles to optimize detection over the full extent of the fusion line. The fine beam spot size results directly in improved resolution with which to better quantify the extent of accumulated damage on the basis of response origin rather than response amplitude. Used in combination with realistic mockups, a far superior inspection results.

HRSG Plant Stub Tube Weld Testing

As previously discussed, conventional plant stub tube weld inspection has evolved from surface techniques to semi-quantitative focused UT to quantitative linear phased array UT. However, because of significant differences in the materials of construction, the behavior of these materials, access limitations, and the high rate of fatigue life consumption through unit cycling, the inspection of stub tube welds in high temperature modules has demanded the use of the quantitative approaches (linear phased array UT) from almost the very beginning of service.

Specifically, there are clearly different susceptibilities to damage between the low alloy (1.25CR-0.5MO and 2.25CR-1MO) steels used in conventional plants and the 9 Chromium steels used in HRSG's. The 9 Chromium materials have a high sensitivity to fabrication variables such as root defects, heat-treatment, and essential welding parameters. Also, access in most HRSG's is much more restrictive than for stub tubes in headers at conventional plants. These are all factors that impose more quantitative results from the NDE efforts expended on a component and in the case of stub tubes the preferred technique is linear phased array. In addition to the quantitative capabilities that are brought to bear using the linear array technology, implementation under conditions of limited access is also enhanced. Because the probe need not be scanned mechanically (either manually or otherwise) but rather the beam is swept electronically with the transducer held stationary, the inspection can be implemented at locations otherwise not inspectable by conventional techniques.

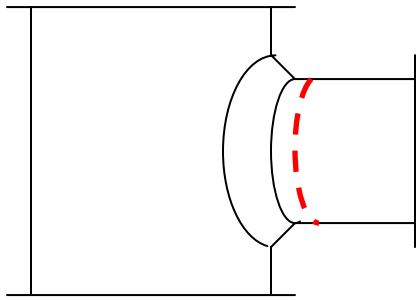
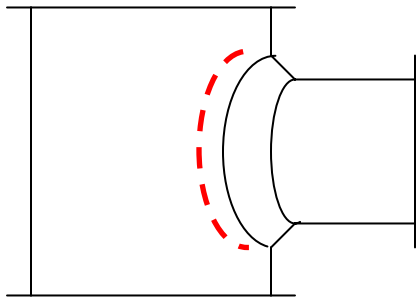
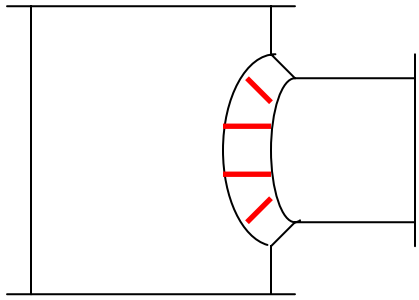
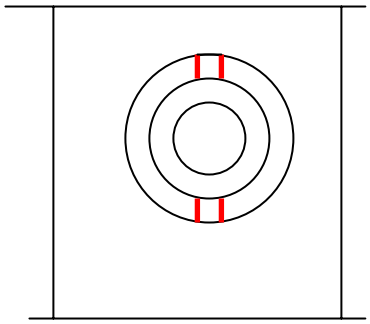
	MODE A: Circumferential Cracking in the Tube HAZ Typically associated with tensile system loads
	MODE B: Circumferential Cracking in the Header Body HAZ Results from bending system loads; however, like Mode D can result from straining in the body.
	MODE C: General Transverse Weld Metal and HAZ Cracking Typically results from greater straining of the branch than the body.
	Mode D: Localized Transverse Weld Metal Cracking on Branch/Body Weldments Results from greater straining in the body than the branch.

Figure 1. Schematic drawing of 4 external modes of cracking in Stub Tube welds.

Figure 2. Examples of Stub Tube Weld failures from root-initiated cracking.

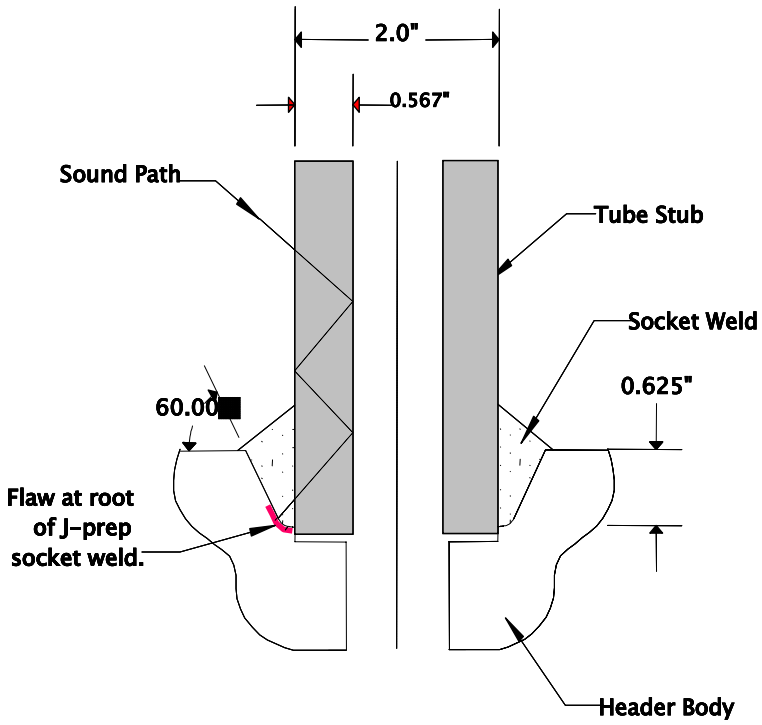
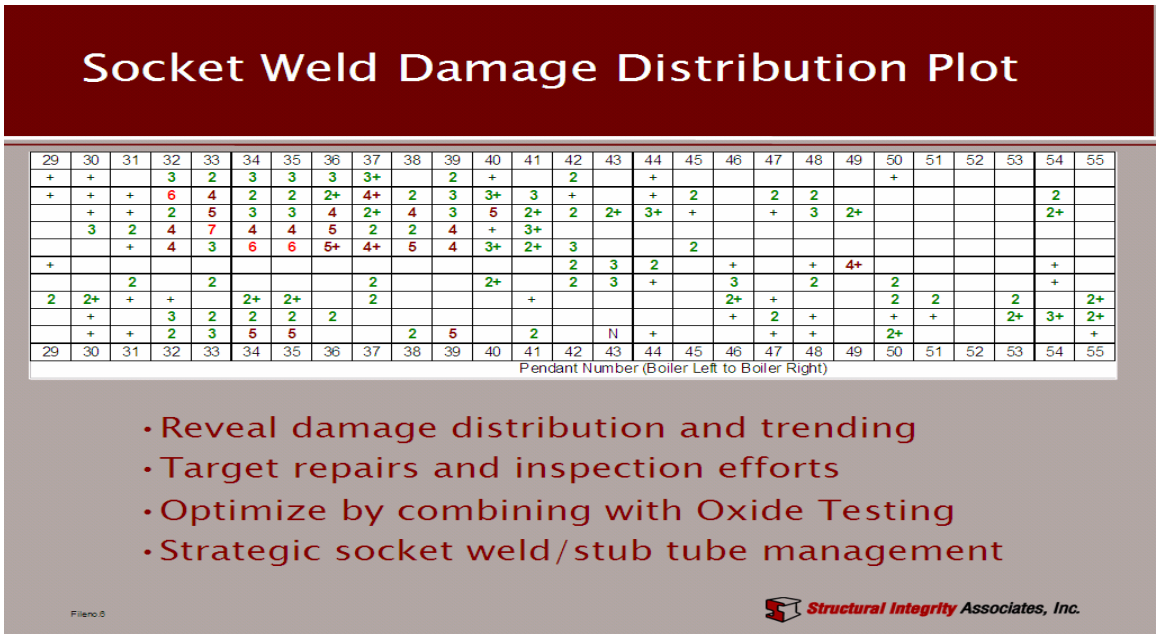


Figure 3. Typical Focused UT technique for root-initiated cracking.



29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55
+	+		3	2	3	3	3	3+		2	+		2		+						+					
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29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55

Header Socket Weld Damage Distribution Plot – Pendant Basis

Qualitative Results of Damage Level

Pendant Number (Left to Right)	33		Front Header	
Tube Row No. (Front to Rear)	Quadrant			
	A	B	C	D
1	NRI	NRI	Level 2	NRI
2	NRI	NRI	Level 1	NRI
3	NRI	NRI	NRI	NRI
4	Level 1	NRI	NRI	NRI
5	NRI	NRI	NRI	NRI
6	NRI	Level 1	Level 1	NRI
7	Level 1	Level 1	Level 3	Level 1
8	Level 1	NRI	Level 2	Level 2
9	NRI	NRI	Level 1	Level 2
10	NRI	NRI	NRI	Level 1

Reference Amplitude

Level 1 ⇨ 30% to 60%

Level 2 ⇨ 60% to 90%

Level 3 ⇨ >90%

Maximum damage level recorded for each quadrant.

Structural Integrity Associates, Inc.

Figure 8. SEMI-Quantitative root-initiated cracking ranking system for monitoring and trending.

Ultrasound Laminography

A unique detection method for creep deteriorated material

Paper to be presented at the International EPRI Conference on Boiler Tube Failures and HRSG Tube Failures, and Inspections November 2-4, 2004, Sheraton San Diego Hotel & Marina

K.G. Schmitt-Thomas, Technical University of Munich, Germany

E. Tolksdorf, Technical University of Munich, Germany

1. Abstract

The newly developed NDT takes advantage of Rayleigh surface waves to detect creep damage and thermally aged structures. It was successfully applied in the field on more than 20 bends in power plants. The technique can be considered as supplementary/additionally to the established replica technique in surveillance testing of high temperature components.

2. Introduction

Components in engineering and power plants are generally exposed to chemical and physical load conditions generally acting simultaneously. These conditions are the consequences of the plant requirement and each individual load condition of the component. It has to be considered that thermal loading is not simply a temperature rise, but merely consists of expansion, thermal stresses, and possibly thermal cycling. The reaction of the material to such a temperature rise is thermal expansion and hence volume increase, which leads to primary and secondary stresses if expansion is restricted. The stresses can be compressive, tension, shear, or torsion which can act on the component in time dependency. It is of vital importance that all loads can act in specific combination and in specific time frames.

It is specific to thermo-mechanical loads that structural processes become thermally activated at a material specific temperature which will lead to time dependant specific material properties. The consideration of an overload in combination with damage has to take into account temperature and temperature distribution, as well as stress and stress distribution in a component, including the time frame in which specific load combinations acted at the site of damage.

Most of the materials in use are in a thermodynamically unstable condition, because their technological properties are the consequences of a tailored sequence of the manufacturing processes. Elevated temperatures can lead to materials modification even without mechanical load, hence leading to temperature and time dependant modification of the mechanical properties and by the latter can react differently to mechanical load.

The deformation of the material promotes hardening which is relaxed by temperature. Hardening can be explained by an increase in dislocation density. As the sub grains coarsen however, the dislocation density decreases, which explains the hardening in the primary region. A typical creep curve consists of three distinct regions, primary, secondary or stationary, and tertiary region. The latter characterises an advanced creep state and can lead to failure of the component. Creep void formation is expected from the mid to the end of the secondary region, which is considered as irreversible.

The creep properties are dominant criteria for the selection of material relative to their application. Creep can best be described by the creep curve which defines the deformation dependency from time at constant stress and temperature. As mentioned before three distinct regions can be depicted.

Region I: (Hardening dominates) Transition region in which the creep rate decreases with time after load application.

Region II: (Secondary creep regime) Hardening and thermal activated processes are compensating each other. Creep rate remains constant, stationary creep regime.

Region III: (Thermal activated processes dominate) Tertiary creep regime with increasing creep rate. Grain boundary gliding is an important process in this regime. Vacancies generated at grain boundaries and precipitates will be transformed to creep voids in the course of creep deformation. Further growth of creep voids will decrease the bearing cross sectional area. During prolonged exposure the voids will transform to micro and macro cracks which could lead to failure of the component. The integrity of the entire component is in question, and hence regular inspection of endangered components is required by the German Steam Pressure Vessel Code. The standard method of inspection, besides standard NDE, is the replica technique which is fairly well established. The surface of the to be inspected area is prepared by extensive metallography and a replica is taken from the surface for further inspection by light microscopy for void concentration and orientation. This technique is

highly time and labour intensive and requires well trained and experienced personnel for preparation and evaluation of the replica. Further, only a very small surface area is investigated and information about the depth penetration of damage is limited. These restrictions necessitate a non destructive method which provides more pertinent information of a larger area and in depth data.

3. Methodology

The Ultrasound-Laminography (Patent No. 19640859.8) has been developed at the Technical University München in the course of a VGB funded research project. The proof of creep damage is carried out directly at the component by measuring the sound velocity with surface waves of variable depth of penetration. The gauge (Fig. 1: gauge, schematic) consists in principal of a pair of transducers, one operating as transmitter, the other as receiver. One transducer is fixed, whereas the other is movable along a defined distance. The transducer's travelling distance is measured very accurately by electronic measuring devices. A continuous surface wave is being generated by the transmitter, which travels along the surface of the component and is received by the second transducer. The phase shift between emitter and receiver is determined by an oscilloscope. By moving one transducer relative to the other a phase shift between the two oscillations is observed. A complete phase rotation of 2π corresponds to a travelling distance of one wave length (Fig. 2: metrology, principle). The receiver's travelling distance during measuring is approximately 50 to 100 mm, and the phase shift of the transducers is recorded as a function of the travelling distance. These data allow the calculation of the mean wave length along the path. The sound velocity (c) is calculated by means of the wave length (λ) and the frequency (f) according to the following equation:

$$c = \lambda \times f$$

The depth of penetration of a surface wave corresponds to a wave length, and hence can be altered by varying the frequency. An entire measuring campaign consists of several repeating travelling passes along the path with different wave lengths (i.e. depth of penetration). This yields the sound velocity as function of the depth of penetration, and further the sound velocity at the surface and a possible variation of the latter in depth.

A near surface creep damage results in a gradient of the sound velocity with depth. At the point of maximum damage the lowest sound velocity is measured at the sur-

face. It will increase in depth if the wave penetrates into less and lesser damaged material.

4. Field Measurements

4.1 Damage dependant gradient

The data of a highly damaged bend is presented in Fig. 3: measurement of highly damaged bend. The measurements have been performed at the extrados (highest stresses), and at a position slightly shifted. The damage at the extrados could be attributed to VGB (Technical Association of Large Power Plant Operators, Essen, Germany) damage class 3b/4 (i.e. numerous voids and micro cracks). VGB damage class 2a/2b (i.e. single voids) has been measured at the shifted position. Both curves indicate a distinct increase of sound velocity from surface into depth.

The measurement of the same bend, however at the neutral phase, is shown in Fig. 4: measurement of undamaged bend. No creep damage could be recorded by metallography. This is indicated by almost constant sound velocity as function of depth.

4.2 Time dependant variation of sound velocity

Sound velocity of a material under long term thermal exposure is not constant, but varies with exposure time. The time of service exposure and the temperature have to be considered when evaluating the absolute value of sound velocity. Normalised material indicates an increase in sound velocity during service exposure, which is due to thermal relaxation of lattice distortions. This is proofed by measurement of X20 CrMoV 12-1 after different service exposure times (Fig. 5: sound velocity as function of exposure time and creep damage). The sound velocity is lowest in the virgin and normalised condition, and increases with increasing exposure time. It is to be expected that the sound velocity approaches a saturation level which is representative of the expected value of material after long service exposure. The saturation value is increased by approximately 30 to 40 m/s compared to the virgin material in case of the X20 CrMoV 12-1. Creep damage, particular in the form of voids however, decreases the sound velocity. As Fig. 5 shows, if this time and temperature dependant change of sound velocity of a given material is known, measurement of sound velocity can be a proper means to detect components at risk of creep damage.

5. Summary

Long term thermal and mechanical exposure of components in the high temperature regime results in plastic deformation, which leads to voids and cracks at grain boundaries during long exposure times. This damage results in a reduction of the load bearing cross section which can lead to component failure. A survey of endangered components is currently carried out by replica technique. The latter is capable of analysing a small fraction of the surface only, with restricted information of the damage gradient in depth. This technique is time and labour intensive.

The newly developed technique is capable of analysing larger areas; determine the damage gradient in depth, and discover thermally activated structural modification. More than 20 bends have been successfully tested on site by this new technique, which represents a very promising supplement/alternative to the current replica technique. The meaningfulness of the measurement depends largely upon the knowledge of the time dependent variation of sound velocity during service exposure. It is therefore important to carry out numerous measurements of material in various structural conditions in order to derive selection criteria for purely thermally damaged (i.e. aged) and irreversibly damaged structures. Tests have commenced on girth welds in the axial and longitudinal direction. More data are required to proof whether this technique is suitable for this particular type of weld testing.

6. References

[1] Kellerer, E.: On site creep detection by measurement of sound velocity. VGB PowerTech, 4/2002, pp 106-109

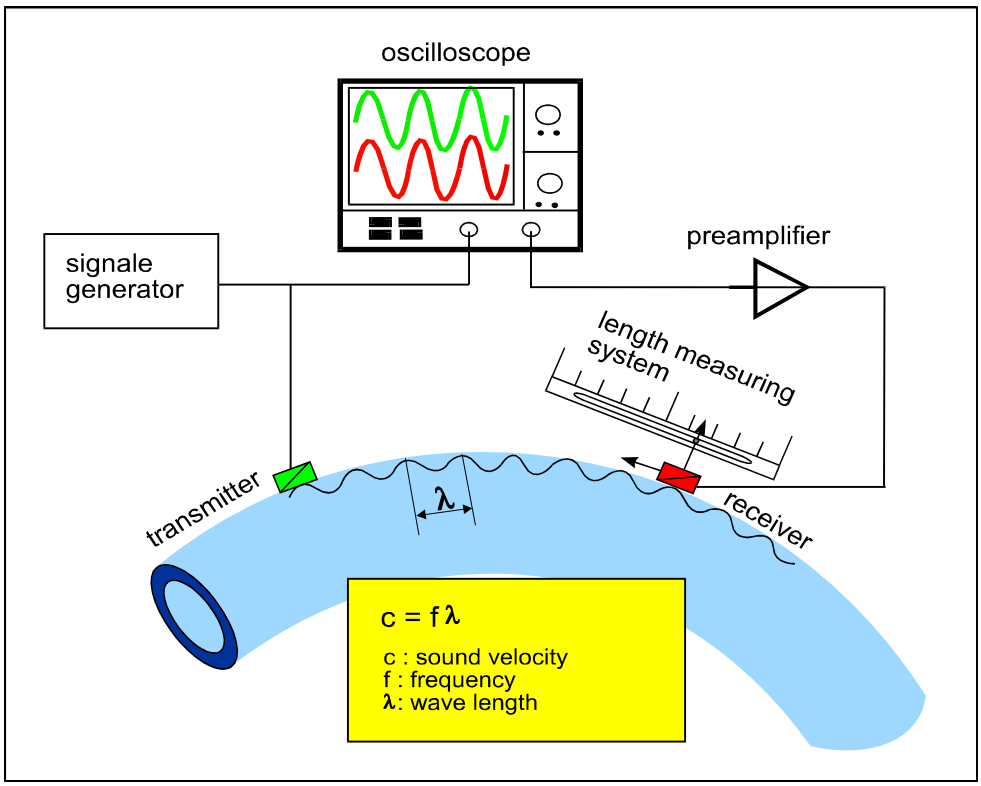

Fig. 1: Gauge, schematic

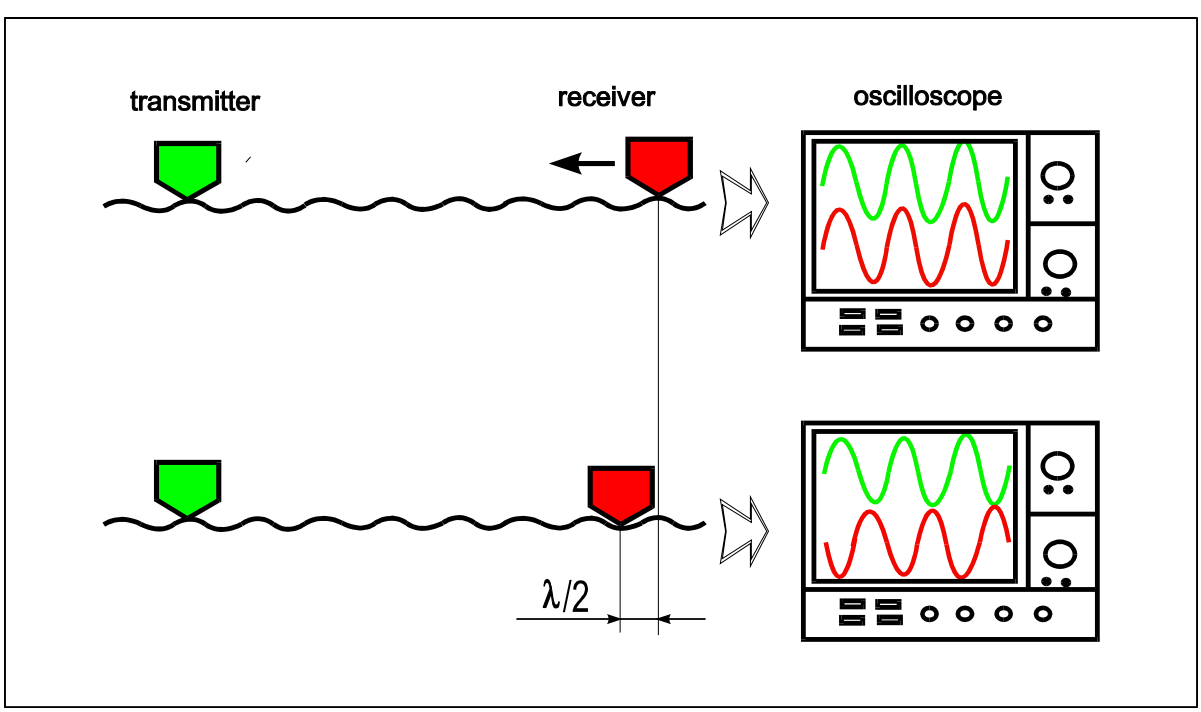

Fig. 2: Metrology, principle

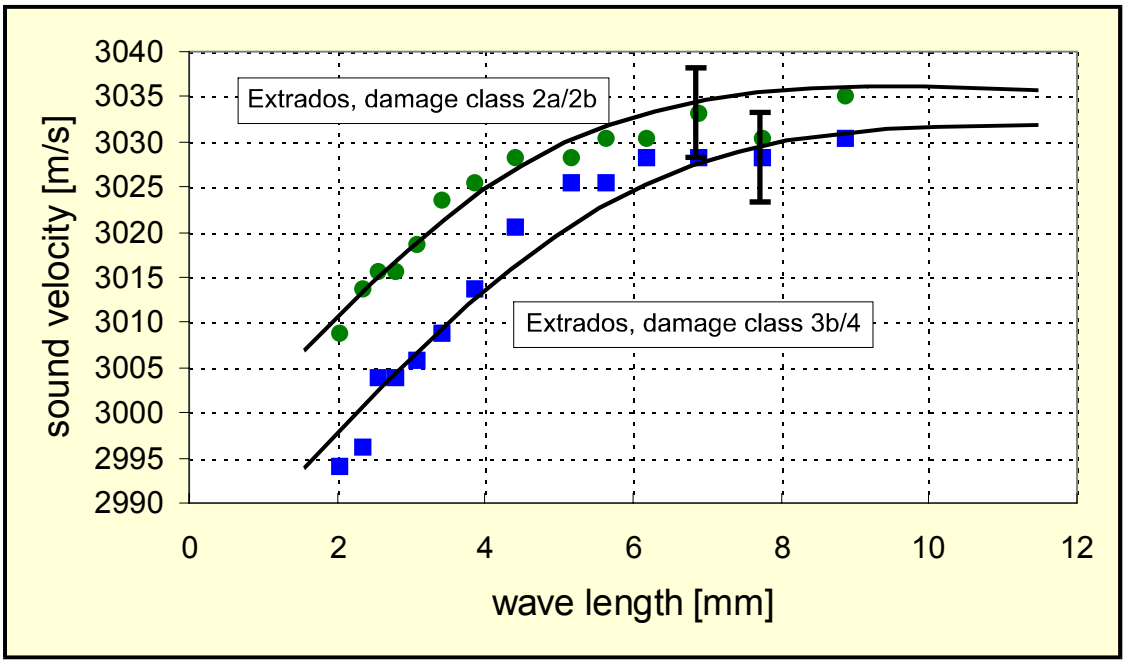

Fig. 3: Measurement of highly damaged bend

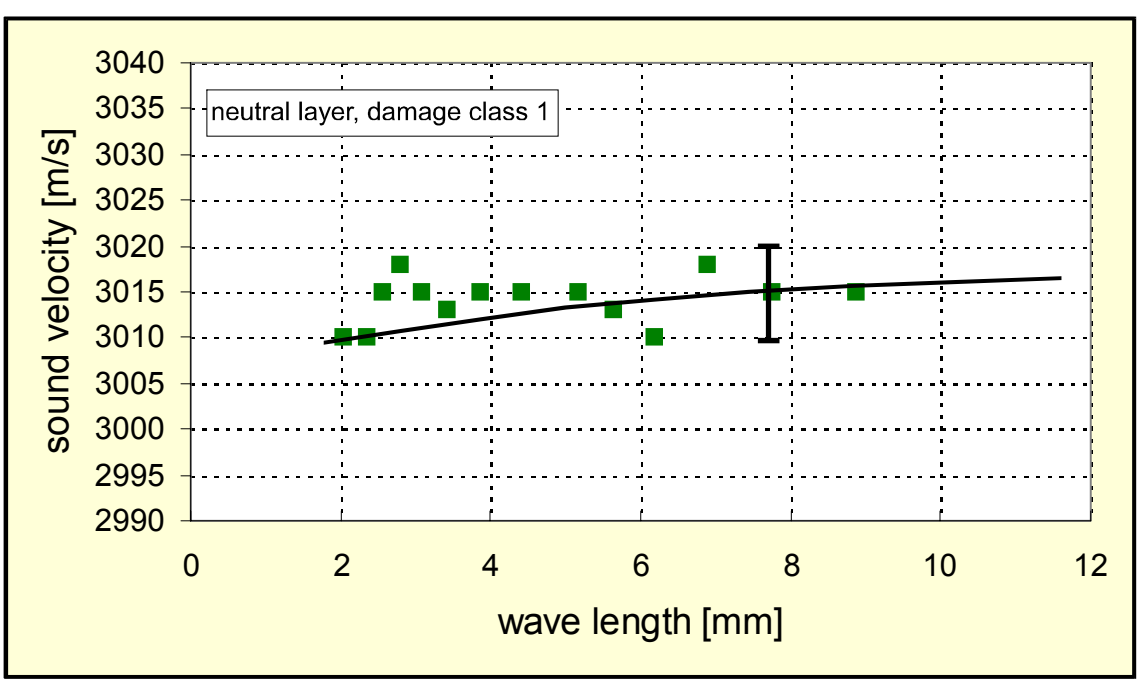

Fig. 4: Measurement of undamaged bend

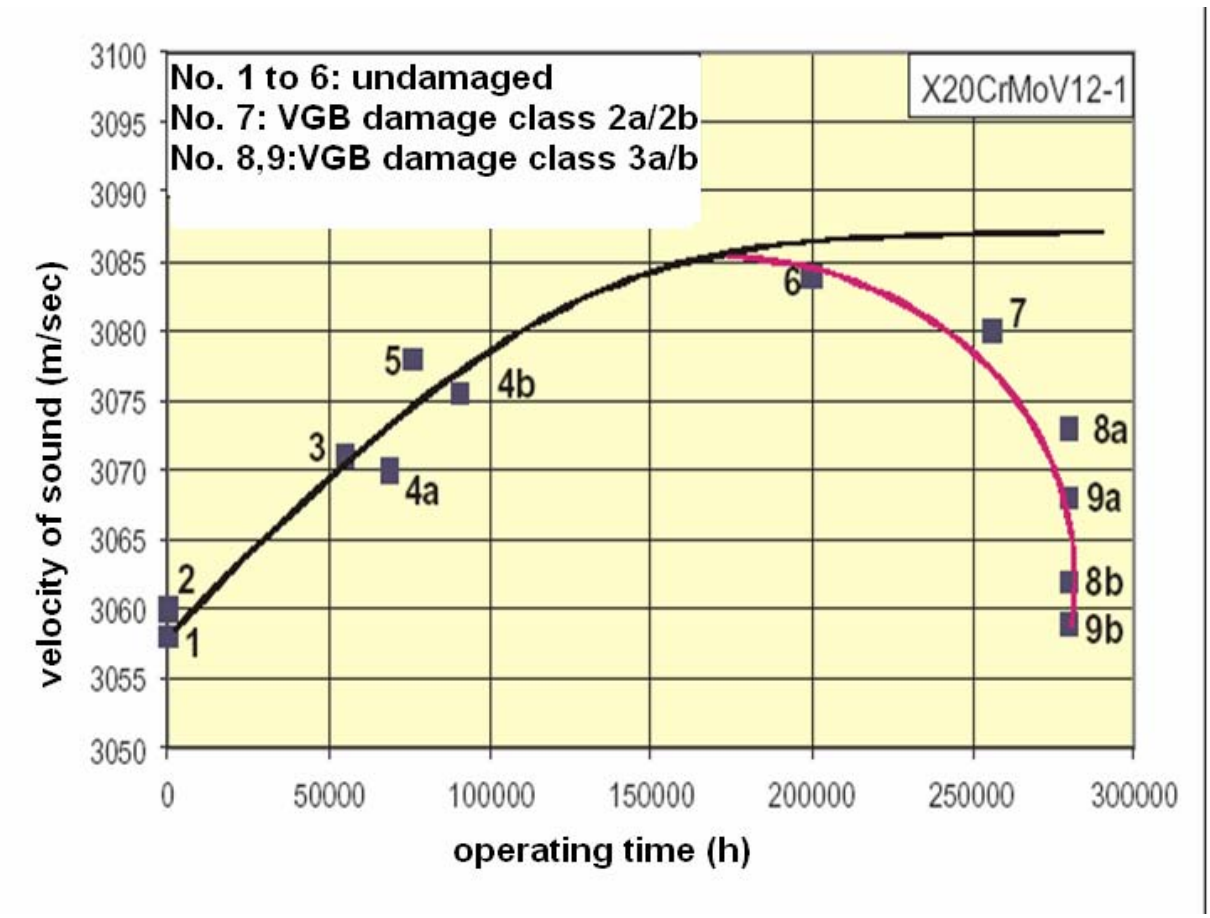

Fig. 5: Sound velocity as function of exposure time and creep damage [1].

Coordinating NDE Techniques for Examination of HRSGs

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ABSTRACT

Over the past 10 years, as Heat Recovery Steam Generators (HRSGs) have become more complex and operating at multiple pressures and temperatures, with reheat, once-through or once-through/drum designs, they have experienced an ever increasing array of HRSG tube failures (HTF). Many of the failure mechanisms are identical to those that have occurred in conventional plants over the last 25 to 40 years, thus the understanding developed can be directly applied to HRSGs.

EPRI recently published "*Interim Guidelines for the Non-Destructive Examination of Heat Recovery Steam Generators.*" This paper discusses the Guideline recommendations on where to inspect within HRSGs and which nondestructive evaluation (NDE) methodology to use in order to identify the specific type of damage in specific locations. Information on performing NDE during shop fabrication, during on-site construction, during commissioning, and periodically during service is provided.

INTRODUCTION

Modern HRSGs have numerous varieties available within the basic designs; which, over the past decade, have become remarkably complex, operating at significantly higher pressures and temperatures. Although these more advanced units are relatively young, they have already begun to experience HTF [1]. Headers and piping have also experienced degradation. Failures are typically caused by mechanisms identical or analogous to boiler tube failures in conventional plants, about which there are some 25 years of research available for the diagnosis and prevention [2]. Applying the appropriate NDE methods to each of the components and damage mechanisms is the key to maintaining safe continued operation.

Because the construction of most designs of HRSGs severely restricts access without cutting out many other tubes, forced outages to repair tube lengths may be lengthy and costly. Once the failed tubes are removed, the tubes must be reinstalled and receive a new heat treatment, a process that will occur in a much more difficult environment than the original factory construction. The integrity of repaired HRSG modules, particularly in difficult locations such as tube-to-header attachment welds, is likely to be of lower quality than the original factory fabrication; thus, further failures may occur after a relatively short time [1].

HRSG PRESSURE PART COMPONENTS AND CHALLENGES TO NDE

HRSGs are complex systems of tubing, headers, drums and piping that work in concert to transfer the heat energy from hot combustion turbine exhaust and/or duct burner gases into the kinetic energy of pressurized steam. The ultimate goal of the HRSG is to transfer heat in a most efficient manner. This requires close tolerances and dense packing of the HRSG enclosure. To optimize the heat transfer efficiency, most of the tubing includes segmented or solid spiral-wound fins. The individual elements of the system are brought together in close proximity to one another in an attempt to optimize the heat transfer efficiency. It is the presence of tube fins and the close proximity of HRSG components that provides the bulk of the challenges to effective NDE.

Modern HRSGs are made up of modules that are positioned along the gas path and designed to extract heat uniformly from the flowing exhaust gasses. Each module contains some number of elements, or "harps", as they are referred to in current construction. Harps are comprised of tubes and headers that are welded together in the shop and then shipped to the site for erection. Tubes, headers, drums and piping in various product forms are the basic building blocks of a HRSG pressure part system. These are the raw materials used to make the harps that make the modules and form the HRSGs.

Once assembled, access to most segments of the HRSG tube circuits is limited. Currently used inspection techniques such as visual, liquid penetrant PT, wet fluorescence magnetic particle, and ultrasonic examination methods are only practical at the module leading and trailing edges and within the header enclosures. Therefore, it is important that quality control/quality assurance (QC/QA) during manufacture and installation be capable of finding all manufacturing defects.

HRSG Tubes and NDE

The primary purpose of an HRSG tube is to transfer heat generated by the combustion process to the water and/or steam within the tube. The tube must also have sufficient mechanical strength (a function of its diameter, wall thickness, and material of construction) to contain the internal pressure, as well as adequate resistance to corrosion on both fluid surfaces. These requirements must be continuously met over the required life of the HRSG, usually well in excess of 100,000 operating hours.

HRSG designers predominantly utilize finned tubes to increase the convective heat transfer from the exhaust gas to the tube wall. The use of finned tubes makes the circuits more compact, but also more difficult to access. The integrity of the bare tubing (which may contain a seam weld) and the fin bond to the tube must be verified during the shop fabrication stages of life. Incomplete fusion in the electric resistance seam welds has been identified as the initiation site for numerous in-service failures. Bare tubes are sometimes used downstream of supplementary burners to limit their metal temperature since they are exposed to increased radiant heat transfer and higher gas temperatures.

Standard tube sizes supplied in the bare tube condition are most often used to begin the HRSG building process in the shop. Most tubes purchased are constructed of carbon steel in the component sections operating below 800°F (427 °C). The carbon steel tubing is often made from electric resistance welded material in order to reduce costs. Suppliers send the tubes to the shop for attachment of fins, bending, welding, etc.

Close visual examination during attachment of fins and select destructive mechanical strength test of the fin-to-tube bonds on completed tubes will locate some manufacturing defects such as incomplete fusion.

Seamless carbon steel and alloy steel tubing should also be examined in the shop prior to fin attachment. Specific concerns include:

- Internal corrosion of improperly capped tubes
- Residue from corrosion inhibitors
- Dents
- Abrasions
- Out-of-specification chemistry
- Dimensions
- Mechanical properties
- Other imperfections

Examiners should spot check tube dimensions, hardness, and alloy chemistry to verify that alloy tubing meets specification before further processing tubes. For seam-welded tubes, hydrotesting, perhaps with a prolonged hold time, should be performed to verify that the seam-welding process produced adequate fusion. Since only a small fraction of the wall thickness needs to be fused to survive a hydrotest, even prolonged hydrotesting of seam-welded tubing will not verify that the seam welds have complete fusion across the entire wall thickness; accordingly, NDE methods such as eddy current or ultrasonic examination have been proposed as a QC/QA test for seam-welded tubing.

Tube Fin Design, Construction, and NDE

Finned tubes are predominant in HRSG units. They have significantly larger surface areas and, thus fewer tubes are needed to achieve a desired fluid thermal energy output. The use of finned tubes can increase the effective heating surface of a tube by a factor of 10 [3]. Effective heat flux is higher because of the large ratio of external to internal surface area. Tube wall temperatures will be higher with finned tubes because of the heat flux difference. Unfinned or bare tubes are used in the highest temperature parts of superheat circuits in some units, most commonly downstream of supplementary burners, in order to avoid excessive peak temperatures.

Tube fins naturally operate at higher temperatures than the tube, and thinner/taller fins operate at higher temperatures than thicker/shorter fins. For every tube diameter, there is an optimum fin height that results from balancing increased heating surface, fin tip temperature and heat conduction through the contact surface of the fin to the tube.

Fins may be segmented or plain. It has been estimated that 90% of the fins in HRSGs are segmented, plain fins being primarily used in SH tube bundles [4]. Fin type and densities will vary depending on the fuel used. For ash-bearing fuels such as heavy oil, plain fins and fin densities may be slightly less than for natural gas and No. 2 diesel oil. Thicker fins, which may or may not be spaced farther apart, are used in colder sections of the economizer or feedwater preheater section for corrosion protection. Downstream of selective catalytic reduction, fin spacing needs to be larger to limit the performance degradation effects of ammonium bisulfite/sulfate deposition and to facilitate periodic cleaning to remove the deposits.

By using high-frequency resistance welding to attach strip material to the outside diameter, fins are joined to the pressure tubing. The process results in very little melting at the interface, even though a sound and continuous joint results; thus, there is not typically a problem with dissimilar metals used for the pressure tubing and for the fins [3]. Fin materials will vary according to expected service conditions. For example, near the gas inlet, stainless steel fins on carbon manganese steel pressure tubing may be used to resist oxidation.

The NDE of finned tubes ready to be assembled into HRSG modules consists of visual and destructive testing of the fin bond strength. The bond must have sufficient strength and ductility to withstand service loads and provide good heat transfer.

NDE of Tube Bends and Welds

Many designs utilizing HRSG tubes require tube bending and welding during manufacture. Tube ovality is a common concern following tube bending. In general, 2% ovality is an acceptable limit that will not result in constricted flow within the tube. Tube bend ovality is defined as the maximum diameter minus the minimum diameter divided by the average diameter. Most HRSG tube bends are gradual over a radius of 3 tube diameters or greater, although 1 or 2 diameter “hairpin” bends are common in horizontal tube HRSGs and in regions of vertical tube HRSGs where lower headers are not installed. Visual examinations and dimensional measurements should be made to verify tube bend ovality.

Most HRSG tube welds are end weld attachments to headers. Some long tubes and/or bent tube sections may require joining of two tubes by welding. Weld quality is verified by visual and radiographic examination for both carbon steel and alloy tubing although there is considerable debate regarding the usefulness of radiography to detect undesirable imperfections in the tube-to-header connections. Welding procedures, welder qualifications, and weld parameters should also be reviewed for alloy tube welds. Weld joints are often the weak link in HRSG tubes because of the wide range of microstructures and properties in the weld metal and the base metal heat affected zone and the geometric features that create local stress/strain concentrations.

NDE of HRSG Headers and Transfer Pipes

Headers serve as the local collection points for steam; water and two-phase mixtures generated within the HRSG tubes. One, two, or three tube rows are usually attached to the headers, depending on the design requirements of the HRSG. Headers are normally located at the top and bottom in a vertical HRSG to promote mixing of the heated fluids. HRSG headers differ in size from those commonly found in large boilers. Most HRSG headers are between 6 - 20 inches (0.15 – 0.51 m) in diameter and 10 - 15 feet (3.05 – 4.57 m) in length, and are of varying thickness to accommodate the design temperatures and pressures.

The process of making a header usually includes starting with sections of seamless pipe or hollow forgings. Transfer pipes are used to feed the headers and carry off the heated fluid. There are usually between one and four transfer pipes per header. Headers are first drilled for attachment of the specified connections, which have been formed from pierced and drawn material. Each connection is circumferentially welded to the header. Visual, magnetic particle, and/or liquid penetrant examinations are performed on the header and attachments prior to attachment of the tube row(s). Once the tubes are installed, visual examination combined with magnetic particle or liquid penetrant examination may also be performed. The final "harp" assembly is then hydrostatically tested to verify the integrity of the welded connections. Harps are in a convenient form for shipping to the job site, where they are placed into position within the HRSG modules. This is the point in construction that access becomes increasingly limited since the spacing between harps is kept to a minimum.

Further limits to access of the finned tubing occur from the positioning of baffles between the headers. As the harps are placed into position and support structures are completed, the HRSG assembly gets more complete and less accessible. The erection of the upper casing and a small stagnant air space in the header enclosures to limit thermal losses essentially seal the harps into place within the HRSG modules.

Transfer pipes are welded into place to link adjacent harps and in-line flow paths. Sometimes, it is necessary to force the alignment of transfer pipes, which could lock in stresses or distort harp alignment. Transfer pipe welds are checked by radiography. It is advisable to maintain close control of welds made to high alloy materials such as P-91 grade. Visual and dimensional checks should be made to verify that harp positions are symmetrical throughout the HRSG and do not yield excessive clearances that may create areas for exhaust gasses to bypass flow paths through the finned tubing.

HRSG Drums, Drum Internals, and NDE

As with all boilers, HRSG drums offer a unique perspective on boiler operation by providing access to fluid side surfaces.

Shop assembly of the drums includes longitudinal and circumferential welds used to attach formed plate material into the final drum dimensions. These welds are 100% inspected using radiography, and the code requires that radiographic film be kept for 10

years. HRSG owners should make provisions to either copy or otherwise secure the film before it is discarded. This film may be useful as a baseline NDE tool for the drum components. Drum attachments are positioned and welded to the vessel in the shop. The completed drum and attachments are stress relieved and then shipped to the job site for erection.

Many of the new, large capacity HRSG designs are triple pressure operation, meaning that they are equipped with three drums. Each of these three drums offers a unique perspective into water chemistry control and future susceptibility to corrosion problems. Drum internals should be checked prior to operation to verify proper positioning of steam sampling, blowdown and chemical injection lines. Threaded connections between segments of these lines should be tack welded to prevent rotation in service from dynamic upset conditions.

HRSG drums are connected to headers and feed piping by risers and downcomers, which are welded in place in the field. Welds are checked using visual and radiographic examination techniques.

HRSG Piping Systems and NDE

HRSG piping systems may have differing levels of complexity depending on the service duty of the plant. Some HRSGs may be co-generators that supply steam to an adjacent facility. Other facilities may be the product of re-powering where the steam turbine of the existing unit has been retained. These scenarios may require long lengths of steam piping. Some modern HRSGs use P91 material for main steam and hot reheater piping in order to reduce the weight of the piping system. This material requires close quality control and quality assurance especially with regard to review of welding procedures, welder qualifications and welding parameters and post weld heat treatment procedures and parameters used in order to avoid susceptibility to creep and/or fatigue damage at weld joints.

The most widely used forms of NDE for HRSG pipe welds are magnetic particle and liquid penetrant used for surface flaw detection and radiographic and ultrasonic techniques used for volumetric examination. Visual examinations should be performed to evaluate the overall condition of the piping system, supports, attachments, routing, and clearances during thermal expansion. Piping supports should be monitored in both the hot and cold positions during commissioning to verify that system design movements are as predicted.

After Assembly, Access Denied

Access to HRSG components becomes increasingly limited as the building blocks of the HRSG are put into place. Figure 1 further emphasizes that point, showing the partial field erection of an HRSG. Once the erection process is completed, traditional NDE methods may not be practical due to access limitations. The challenge for the HRSG operator following commissioning will be to combine on-line operating information with periodic in-service inspections and a pro-active HRSG pressure part plan to avoid costly failures.

Figure 1. Photograph of a Partly Finished HRSG Assembly

FOCUSSING NDE SPECIFICALLY FOR KNOWN OR SUSPECTED MECHANISMS OF DEGRADATION

Fifteen damage mechanisms have been identified that are known to cause HRSG tube failures (HTFs), many of which can also cause damage to piping and headers [1]. Four of the mechanisms are forms of fatigue; seven are forms of corrosion; two are types of overheating; and two are special-case cracking mechanisms.

Service-Induced Damage Mechanism Summaries

Damage mechanism summaries were produced that provide a concise guide to each of these service-induced damage mechanisms when one or more of them are known or suspected to be active. The format for each damage mechanism includes:

- A brief summary of the mechanism
- A description and pictures showing the appearance of the damage
- A listing of where it occurs
- How to find and quantify the damage

- Optional NDE techniques
- Acceptable levels of damage
- Repair options
- Correction actions
- Any interrelated damage mechanisms that may also be active
- Other comments [5]

Corrosion Fatigue

Corrosion fatigue is damage and cracking resulting from the combined action of cyclic stresses and a corrosive environment. Crack initiation involves repeated mechanical disruption and healing of the protective oxide scale on water-touched surfaces, resulting in aligned corrosion pits. Crack-like pits form next, followed by multiple, transgranular, oxide-filled cracks oriented normal to the predominant tensile stress field. Cracking is influenced by a complex interaction of the rate and magnitude of loading (strain), fluid pH, dissolved oxygen levels, and alloy chemistry.

Since corrosion fatigue initiates at the inside surface, damage may not be visually apparent on the outside surface. Damage which has progressed through-wall may first appear as a pinhole leak. On the inside surface, multiple, parallel cracks, often associated with corrosion pits or surface discontinuities that can be either axial or circumferential may be apparent. Cracks are oriented normal to the predominant tensile stress.

Corrosion fatigue occurs on water-touched components, especially economizers, but can also occur in steam-touched tubing that contains air-saturated condensate during outages. It is most likely to occur at locations with welded connections, bends, and at attachments where thermally-induced forces and moments are highest or at header/drum boreholes.

Damage can be detected with videoprobes and borescopes. Angle beam ultrasonics can also detect corrosion fatigue when using custom transducers for specific locations of concern. The severity of the damage is quantified via ultrasonic flaw sizing and tube sampling. If cracks are detected, fitness-for-service analysis should be performed to justify continued operation. The recommended repair option is replacement of the affected area. Temporary pad weld repairs are not recommended. [5]

Thermal-Mechanical Fatigue

Thermal-mechanical fatigue damage and cracking occur when thermal expansion and contraction is restrained sufficiently to produce localized material yielding. Repeated thermal cycles eventually result in crack initiation and growth. Appearance of damage at the outside surface most commonly consists of single cracks, oriented normal to the predominant tensile stress field that can be oriented axially or circumferentially and may be multidirectional at attachments. At the inside surface; only cracks which have penetrated the wall thickness will be visible.

Damage occurs at water- and steam-touched components in all HRSG sections, most likely at welded connections (such as tube-to-header welds) and attachments, and occasionally at bends. Locations with significant thickness transitions and locations where thermally-induced forces and moments are highest are most likely to experience thermal-mechanical fatigue.

Visual, magnetic particle, and liquid penetrant examinations are used to detect thermal-mechanical fatigue and the severity of the damage may be quantified with ultrasonic examination and exploratory grinding. If cracks are detected, fitness-for-service analysis should be performed to justify continued operation. Cracks may be left in place (if justified). Otherwise, local excavation, excavation and weld repair, or complete replacement of the connection may be required. [5]

Creep Fatigue

Creep fatigue is damage and cracking resulting from the synergistic effects of cyclic stresses and exposure to an elevated temperature environment. Sources of stress include internal pressure, thermal gradients, constraint during thermal expansion, and dead weight loads. The formation and fracture of the thermally-grown surface oxide scale may strongly influence creep fatigue life.

The appearance on the outside surface typically consists of single cracks oriented normal to the predominant tensile stress field (typically circumferential near tube-to-header connections) that can be axial (in bends) or multidirectional (at attachments). At the inside surface, borehole cracking in headers can be seen and may be multidirectional.

Damage typically occurs at locations exposed to temperatures in the creep regime, typically steam-cooled and not water-cooled components, high pressure and intermediate pressure superheaters and reheaters. Locations with welded connections, bends, attachments and header boreholes are more likely to suffer from creep fatigue damage.

Damage can be detected with visual, magnetic particle, and liquid penetrant examinations. Damage may be quantified with ultrasonic examination, alternating current – potential drop, replication, or exploratory grinding. If cracks are detected, fitness-for-service analysis should be performed to justify continued operation. The recommended repair option consists of local excavation (including all creep-damaged material) and weld repair or complete replacement of the connection. [5]

Flow Induced Vibration Fatigue

Flow induced vibration fatigue consists of damage and cracking resulting from very high frequency cyclic loading. Sources of flow induced vibration include the buildup of self-reinforcing pressure fluctuations within a tube array, gas flow eddy currents (vortex shedding) that occur near the natural frequency of a tube array, acoustically-induced vibration, and flow instability (turbulence).

The appearance at the outside surface typically includes single, tight cracks oriented normal to the predominant tensile stress field. These cracks are typically circumferential near tube-to-header connections. Separate cracks may be present on opposite sides of the tube and impact damage or cracking of tube fins may be present. At the inside surface, cracking will not be visible unless it has penetrated through-thickness because it originates at the outside surface.

Damage may occur in all sections of the HRSG, but is most predominant in high pressure superheaters and reheaters. Welded connections, bends, and attachments are more susceptible.

Damage may be detected by visual (visual evidence of fin cracking, impact marks, etc.), wet fluorescent magnetic particle, or liquid penetrant examination. The severity of damage may be quantified by ultrasonic examination, alternating current potential drop, or exploratory grinding. No cracking is acceptable. Repair options include excavation and weld repair or complete replacement of the connection. [5]

Flow Accelerated Corrosion

Flow accelerated corrosion (FAC) results from the accelerated dissolution and transport of the normally protective magnetite oxide scale due to the formation of locally reducing, low pH water chemistry conditions, high flow velocity and temperatures in the range of 212°F to 482°F (100°C to 250°C). FAC affects carbon and low alloy steels (but not steels with significant (>0.1 weight %) chromium.

At the outside surface, damage may not be visually apparent, but damage which has progressed through-wall may first appear as a pinhole leak. At the inside surface, a scalloped or wavy ("orange-peel") surface may exist and may be partially covered with a thin, shiny, black-colored oxide or may be bare-metal surface with or without reddish rust.

FAC occurs in water-touched components in the temperature range mentioned above. This typically includes the entire low pressure evaporator circuit, including the steam drum internals and vent/drain lines, near the outlet of the low pressure economizer, and the high pressure feedwater system. Locations with high flow velocities (outlet header tube bends, riser/downcomer pipe bends, and drum steam separators) are also susceptible.

Damage may be detected with internal visual (visual, videoprobe, borescope), ultrasonic thickness measurements (internal rotary inspection probe, or from the external surface), pulsed eddy current (for insulated piping components), or radiography (for small bore drain lines, using tangential or perpendicular beam). The severity of damage is quantified with ultrasonic thickness measurements using a grid pattern or scanning the entire surface or the area within each grid with a typical grid spacing of the diameter divided by 4. If the predicted minimum wall thickness at the end of the next service period (time to next re-inspection) is greater than the specified minimum wall thickness, the component is acceptable. For predicted thickness less than the Code-allowable

minimum, calculations of acceptable local wall thickness must be made. Repair options include replacement of the component with chromium-containing alloy such as 1.25Cr – 0.5Mo or restoration of the wall thickness with a pad weld as a temporary repair. [5]

Acid Phosphate Corrosion

Acid phosphate corrosion is corrosion resulting from the breakdown of the protective waterside oxide layer due to the buildup of internal deposits and the local concentration of phosphate salts, leading to under-deposit corrosion.

Since this is a waterside damage mechanism, no outside surface damage will be visible unless damage has progressed to cause a pinhole leak. The appearance at the inside surface consists of internal tube gouges partially or completely filled with layered deposits, often with a distinct transition between mild and very severe corrosion

Damage occurs in the high pressure and intermediate pressure evaporators on the leading edge side of the tubes and at locations with internal deposits, locations with high heat transfer or high steam quality, gas inlet row tubes, horizontal tubes, and module end tubes.

Damage is detected with internal visual (videoprobe, borescope) or radiographic examination. The severity of damage may be quantified with ultrasonic thickness measurements (internal rotary inspection probe or from the outside surface) or by tube sampling. Damage is acceptable when the predicted minimum wall thickness at the end of the next service period (time to next re-inspection) is greater than the minimum Code-allowable wall thickness. Repair options consist of replacement of tubing when the wall thickness is less than the specified minimum. [5]

Caustic Gouging

Caustic gouging is corrosion resulting from the breakdown of the protective waterside oxide layer due to the buildup of internal deposits and the local concentration of caustic to high pH levels, leading to underdeposit corrosion.

Since this is a waterside damage mechanism, no damage will be visible from the outside surface unless damage has progressed to cause a pinhole leak. Internal hemispherical or elliptical depressions, partially or completely filled with thick layered deposits may be visible. The inside surface of a tube containing caustic gouging will appear similar to that for one subject to acid phosphate corrosion.

Caustic gouging occurs in the high pressure and intermediate pressure evaporators on the leading edge side of the tubes. Locations with internal deposits, locations with high heat transfer or high steam quality, gas inlet row tubes, horizontal tubes, and module end tubes have experienced damage caused by caustic gouging.

Damage can be detected with internal visual examinations using videoprobes or borescopes and radiography. The severity of damage may be quantified with ultrasonic thickness measurements with an internal rotary inspection probe or from the outside surface and with tube sampling. Acceptable conditions exist when the predicted minimum wall thickness at the end of the next service period (time to next re-inspection) is greater than the minimum Code-allowable wall thickness. The repair option is to replace tubing when the wall thickness is less than the specified minimum. [5]

Hydrogen Damage

Hydrogen damage is the tube damage and wall loss that results from the breakdown of the protective waterside oxide layer due to the buildup of internal deposits and the local concentration of acidic contaminants (chlorides and sulfates), leading to underdeposit corrosion.

Since this is a waterside damage mechanism, no outside surface damage will be visible. Localized internal deposition, wall loss, pitting, or gouging may or may not be present on the inside surface beneath the deposits.

Hydrogen damage occurs in the high pressure and intermediate pressure evaporators, on the leading edge side of the tubes and at locations with internal deposits, locations with high heat transfer or high steam quality, gas inlet row tubes, horizontal tubes, and module end tubes.

Hydrogen damage can be detected with internal visual examinations using videoprobes or borescopes and radiography. The severity of damage may be quantified with ultrasonic thickness measurements applied with an internal rotary inspection probe or from the outside surface and with tube sampling. The damage is acceptable when the predicted minimum wall thickness at the end of the next service period (time to next re-inspection) is greater than the minimum Code-allowable wall thickness. The repair option is to replace the tubing when the wall thickness is less than the specified minimum. [5]

Internal Pitting

Internal pitting is the result of localized dissolution of metal in any component in contact with an aqueous solution. It may occur due to air ingress (high oxygen, CO_2 levels) created during improper pre-service storage or poor shutdown and layup practices or due to acidic attack during chemical cleaning.

Since this is a waterside damage mechanism, no outside surface damage will be visible unless the pitting has progressed through-wall. On the inside surface, one may observe localized wall loss in the form of pits, which may be open or filled with deposits and/or corrosion products. A bright red internal oxide scale is evidence of high oxygen levels.

Hydrogen damage occurs on any component in contact with an aqueous solution (including water- and steam-touched tube surfaces) as well as the condenser, condensate piping, deaerating heater and storage tank, and feedwater heaters. In seam-welded tubing, localized pitting at the seam weld is common.

Damage can be detected with internal visual examination using videoprobes or borescopes. The severity of damage may be quantified with ultrasonic thickness measurements using an internal rotary inspection probe and with tube sampling. The damage is acceptable when the minimum wall thickness is greater than the specified minimum wall thickness. For greater pit depths, fitness-for-service analysis should be performed to justify continued operation. The repair is option is to replace tubing with unacceptable pit depths. [5]

Gas-Side Corrosion and Pitting

Gas-side corrosion and pitting is the localized dissolution and/or general wall loss of metal from tubes and/or fins, due to the presence of corrosive species in the flue gas (sulfur compounds if fuel oils are burned or selective catalytic reduction additives are used, atmospheric chlorides, etc.).

Surface pitting and/or wall loss to tubes and/or fins may be present on the outside surface. Deposits and/or corrosion products may also be present. No visible features will be present on the inside surface unless the damage has progressed through-wall.

Damage occurs on gas-touched surfaces, most often in the cold end of the HRSG. Damage can be detected with visual examination. The severity of damage may be quantified with ultrasonic thickness measurements or with a micrometer or other dimensional measurement.

The damage is acceptable when the minimum tube wall thickness is greater than the specified minimum wall thickness. For more severe tube wall loss, fitness-for-service analysis should be performed to justify continued operation. Fin corrosion may degrade performance. Repair options include replacement of tubing. It is also recommended that the owner consider the need for a material upgrade. [5]

Acid Dew Point Corrosion

Acid dew point corrosion is the localized dissolution and/or general wall loss of metal due to the presence of sulfuric acid condensed from sulfur oxides and water vapor in the flue gas at the exhaust end of the HRSG.

Surface pitting and/or wall loss to affected surfaces may be observed on the outside surface. Deposits and/or corrosion products may also be present. The underlying metal may have a gouged or “orange peel” appearance. Fins may be missing or corroded and easily broken off. No visible features will be present on the inside surface unless the damage has progressed through-wall.

Damage occurs to gas-touched surfaces (including tubes, fins, casing, ducts, and stacks) where the metal temperatures are below the acid dew point.

Damage may be detected with visual examination. The severity of damage may be quantified with ultrasonic thickness measurements; however, this method is only applicable to smooth tube surfaces which would require removal of fins to inspect finned tubes. The damage is acceptable when the minimum tube wall thickness is greater than the specified minimum wall thickness. For more severe tube wall loss, fitness-for-service analysis should be performed to justify continued operation. Fin corrosion may degrade performance. Repair options include replacement of tubing. It is advisable to consider the need for a material upgrade. [5]

Stress Corrosion Cracking

Stress corrosion cracking involves the initiation and growth of cracks in susceptible materials due to the simultaneous exposure to tensile stress (applied and/or residual) and an aggressive aqueous environment.

Fine, very tight (and difficult to see), branched cracking oriented perpendicular to the dominant stress will be apparent on the outside surface. Damage often appears as a pinhole leak that will extend in length with exploratory grinding. Fine, tight, branched cracking oriented perpendicular to the dominant stress will be apparent on the inside surface.

Stress corrosion cracking occurs at locations with the potential for the highest concentration of contaminants (for example, condensate collection points) as well as high stresses (both residual and applied, including at bends, welds, attachments, supports, etc). Cracking has been found in a variety of components, including feedwater heater tubing, evaporator tubing, and steam-cooled tubing, in carbon, low alloy and austenitic stainless steels.

Stress corrosion cracking may be detected with visual examination (removal of oxide and use of magnifying lens may be required), magnetic particle, liquid penetrant, or eddy current examination. The severity of damage may be quantified with exploratory grinding. The presence of cracking is an unacceptable condition. [5]

Short Term Overheating

Short term overheating is tube metal temperature excursion to well above the design temperature for a short period of time (minutes to months), due to a partial or complete loss of steam flow. The reduced material strength results in microstructural creep damage, tube swelling, and eventual rupture.

On the outside surface, deformation and distortion of tubing will be present. Possible localized swelling or bulging may also be visible, but swelling may not be visually apparent due to the tube fins.

No visual evidence of short term overheating damage will be present on the inside surface, but blockages may be present.

Damage typically occurs in steam-cooled tubing, especially just downstream of supplemental burners.

Tube damage or deformation may be detected with visual examination. Blockage may be detected with internal visual examination with videoprobes or borescopes by observing flame patterns downstream of supplementary burners. The severity of damage is quantified with tube sampling. The damage is acceptable when the dimensions of tube samples (outside diameter and wall thickness) are within specified limits. Fitness-for-service analysis could be used to justify continued operation with more severe damage. The repair option is to replace damaged tubing. [5]

Long-term Overheating

Long-term overheating is the gradual increase in tube metal temperature and/or stress levels to slightly above the design temperature over a long period of time (many years or decades). The gradual accumulation of microstructural creep damage leads to eventual end-of-life rupture.

With long-term overheating, external oxidation and wall thinning may be visible. Thick internal oxide scale may be present, and may be exfoliated.

Damage occurs in steam-cooled tubing, especially near the high pressure superheater and reheater outlet or just downstream of supplemental burners. Tubing near material changes (the lower grade material), tubing with longer gas-touched lengths, and tubing just before the outlet header are most susceptible.

Damage may be detected by ultrasonic examination by conducting oxide, internal oxide scale, and wall thickness surveys. It may require removal of tube fins from selected areas, or measurements can be taken on bare tubes near the outlet header and extrapolated into the tube bank. The severity of damage may be quantified by calculation of remaining creep life using internal scale and wall thickness survey results, along with tube sampling and metallurgical evaluations.

Damage is acceptable when the estimated or measured tube wall thickness, diameter, and metal temperature are within specified or design limits and estimated creep life exceeds desired life. Repair options are replacement of tubing with insufficient remaining creep life. It is also recommended that an evaluation be made of the need for increased thickness or a material upgrade. [5]

Thermal Quenching

Thermal quenching is a high stress overload-type damage and fracture resulting from thermal quenching of hot tubing from attemperator sprays or condensate.

Tube ovalization, distortion (plastic deformation), or cracking may observable on the outside surface. Distortion or cracking may observable on the inside surface.

Damage occurs in steam-cooled tubing, high pressure superheaters and reheaters, and typically at or near outlet or intermediate tube-to-header connections.

Damage may be detected with visual examination for deformation and cracking and magnetic particle and liquid penetrant examinations. The severity of damage is quantified with crack depth measurements with alternating current potential drop, angle beam ultrasonic examination, or exploratory grinding. No cracking or out-of-specification deformation is acceptable. Repair options include replacement of affected tube-to-header connections and evaluation of the need to replace adjacent tube bends. [5]

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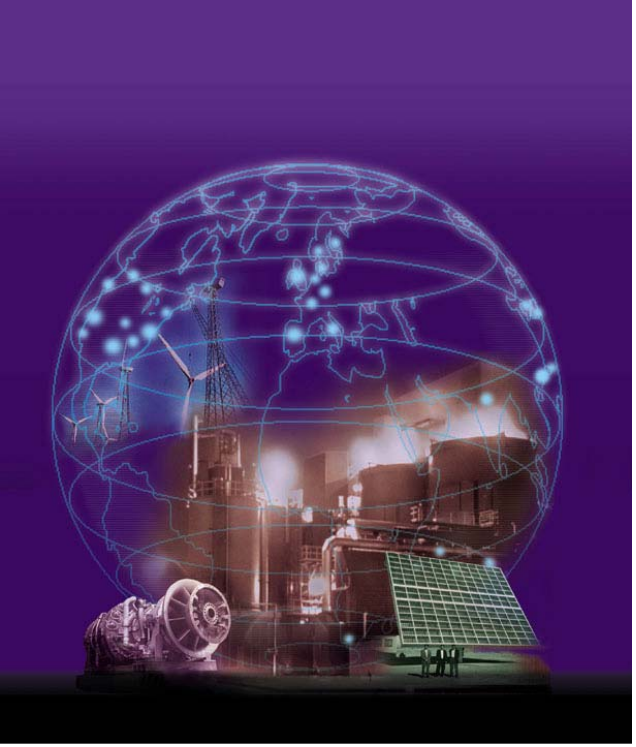

Electromagnetic NDE Techniques for Condition Assessment of HRSG

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Boiler Tube and HRSG Tube failures and Inspections

San Diego, CA November 2-5, 2004

Goals of NDE for HRSGs

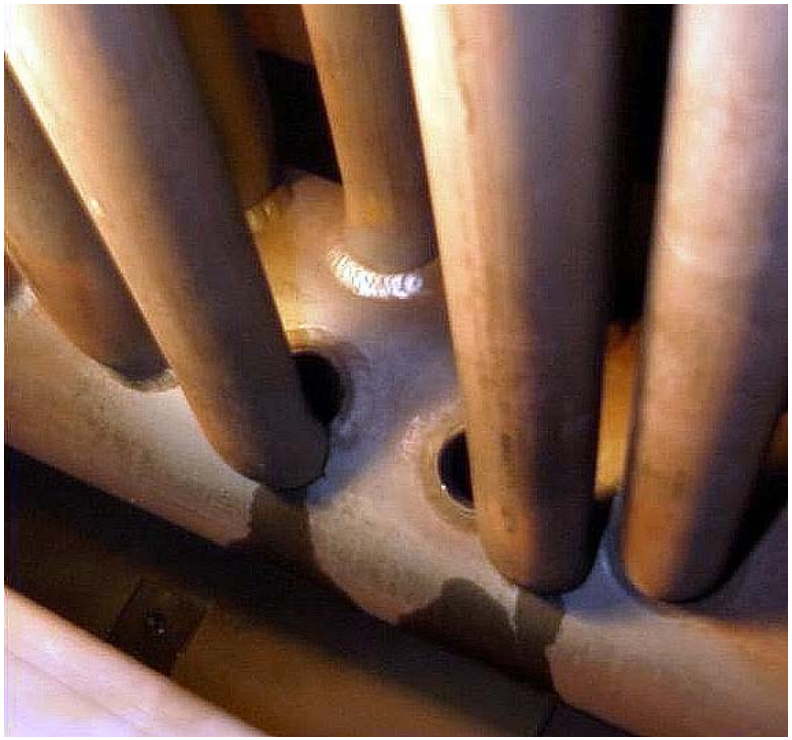
- Assess Current HRSG Conditions
  - Rely on condition-based instead of time in place maintenance approach
  - Assess extent of damage
  - Detect & remove defective & degraded tubes to avoid forced outages
- Assist Management Evaluate Component Life
  - Use comparable data sets to generate damage growth rate
  - Establish remaining operating life
  - Help with repair/replace/run decision

Short-Term Goals

- Assess Applicability of Electromagnetic NDE Techniques
- NDE Applications
  - HRSG tubes
  - Tube-to-header welds
- Focus on Reviewing Commercially Available Hardware/Software Systems
  - OD Applications
    - TesTex
    - Aptec
  - OD/ID Application
    - Russell Technology

Tube-to-Header Cracking

- CS Tube-to-Header Welds
- Nom. Tube Sizes: 1.5-2.0” OD
- Nom. Wall Thickness: 0.105-0.175”



Degraded Finned Tubing

- CS or SS Finned Tubing
- Nom. Tube Sizes: 1.75-2.0” OD
- Nom. Wall Thickness: 0.105-0.175”

TesTex LFET –Low Frequency Electromagnetic Technique

- Applied Originally to Storage Tank and Pipe Wall Thickness Evaluation
- Adapted for Use from OD of HRSG Tubing for OD/ID Flaw Characterization
- Operating Frequency of 10-100 Hz

LFET Operating Principle

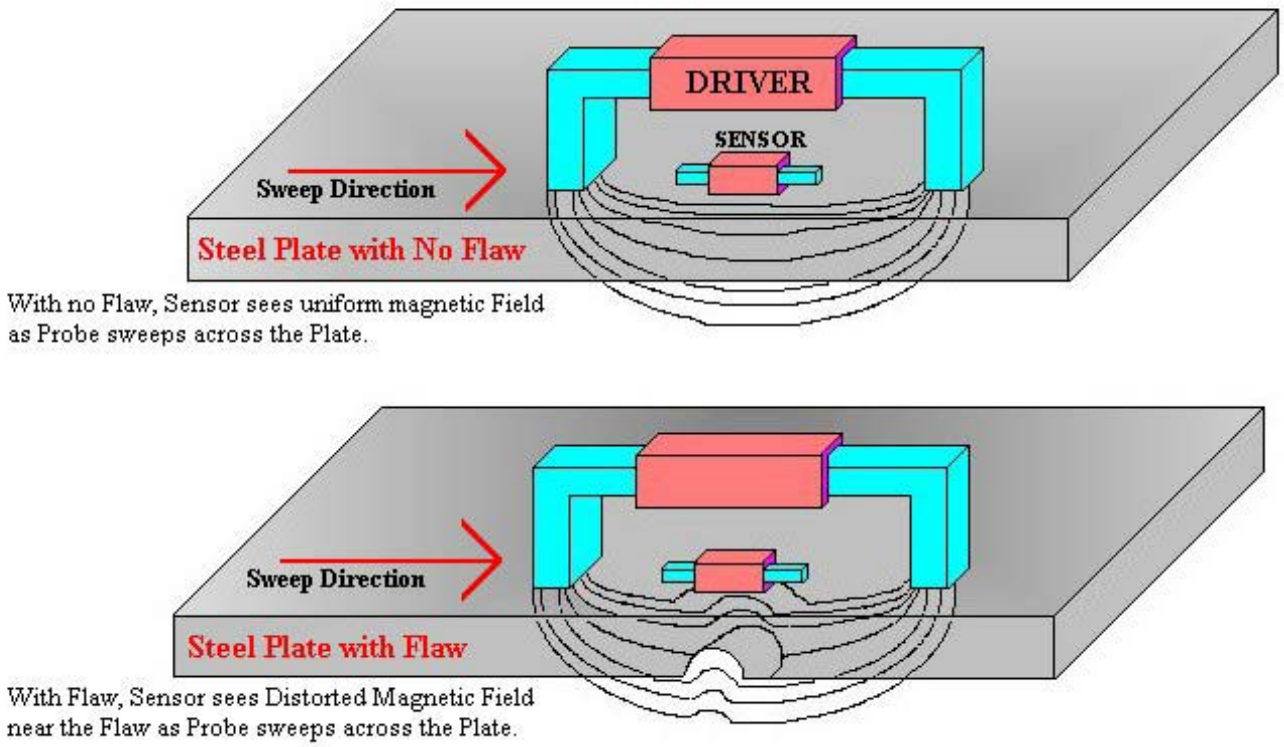
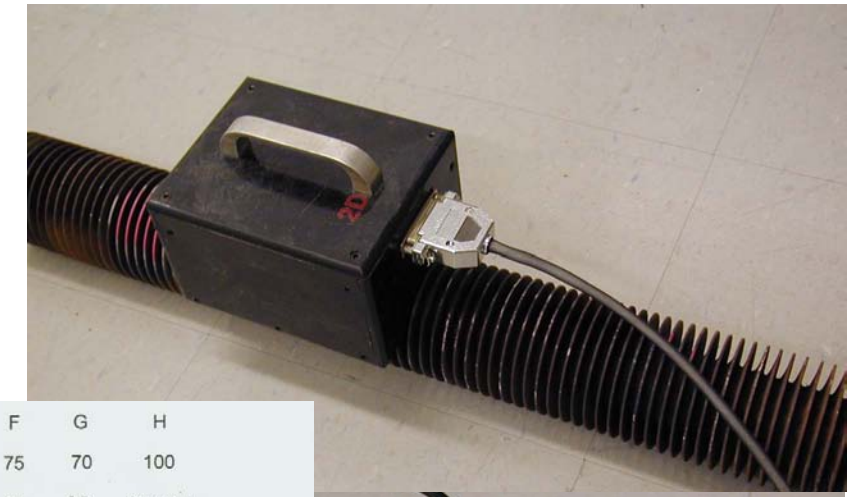


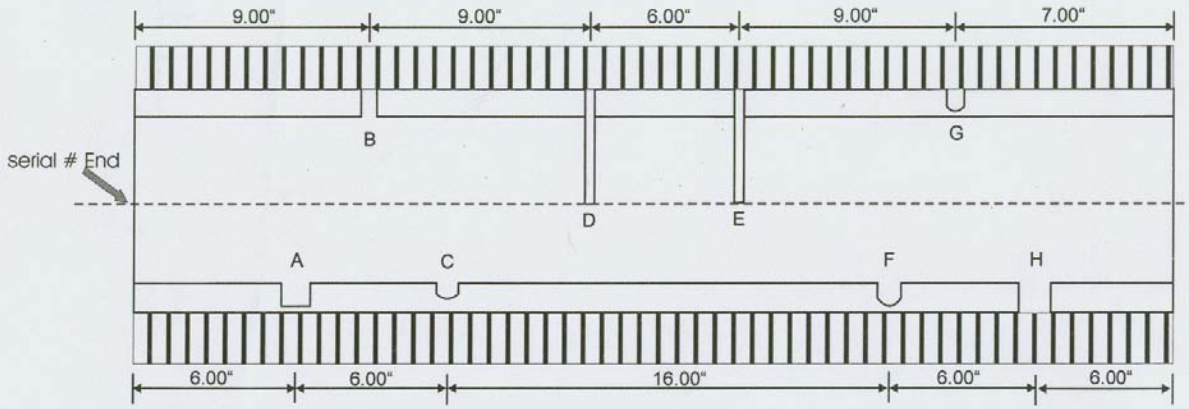
Figure 1.
Principles of Low Frequency Electromagnetic Technique (LFET)

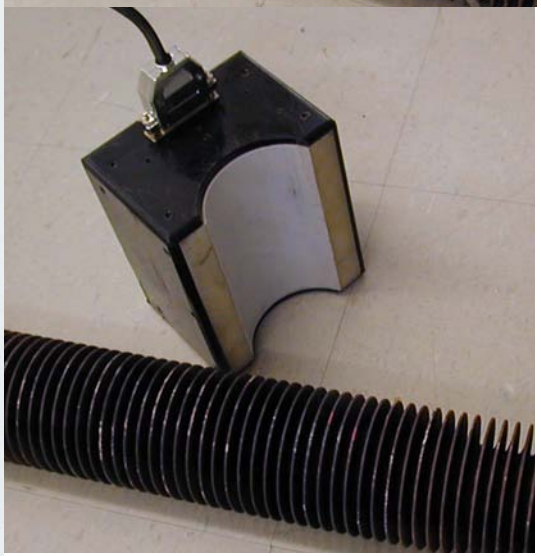
LFET Sensor for HRSG Tubing

- 2” OD x 0.169” Nom Wall Finned CS Tubing
- Fin Height of 0.750” and Spaced 0.250” apart

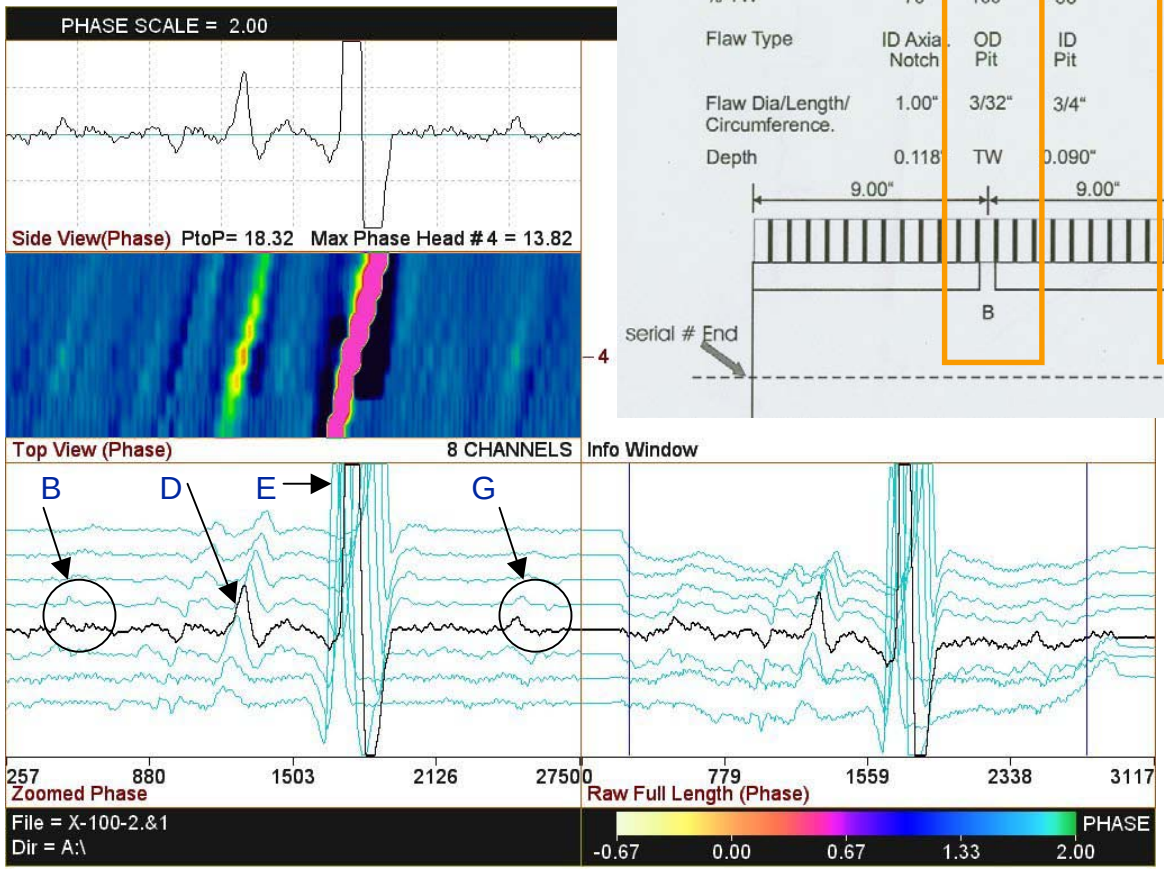


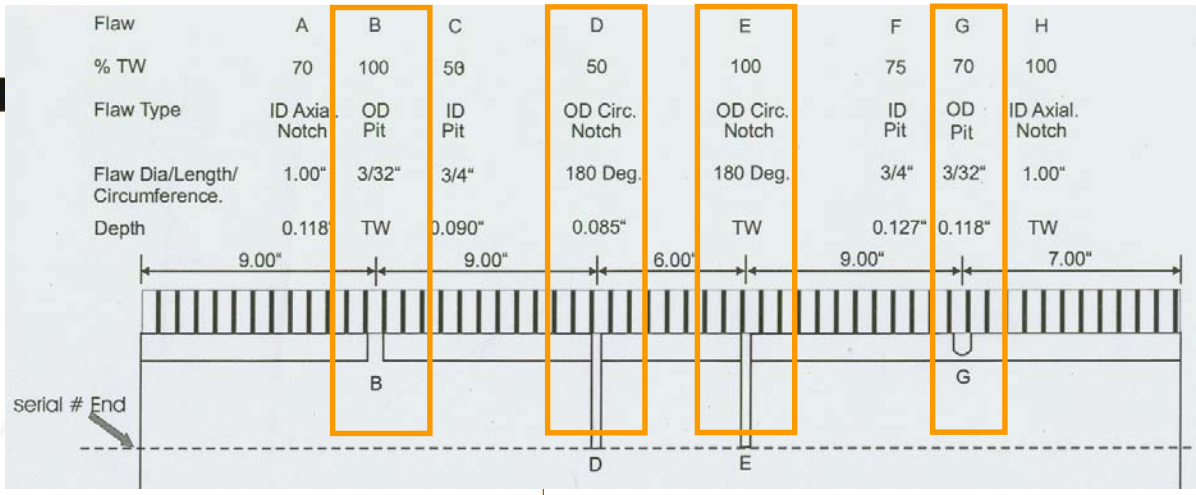
Flaw	A	B	C	D	E	F	G	H
% TW	70	100	50	50	100	75	70	100
Flaw Type	ID Axial. Notch	OD Pit	ID Pit	OD Circ. Notch	OD Circ. Notch	ID Pit	OD Pit	ID Axial. Notch
Flaw Dia/Length/ Circumference.	1.00"	3/32"	3/4"	180 Deg.	180 Deg.	3/4"	3/32"	1.00"
Depth	0.118"	TW	0.090"	0.085"	TW	0.127"	0.118"	TW



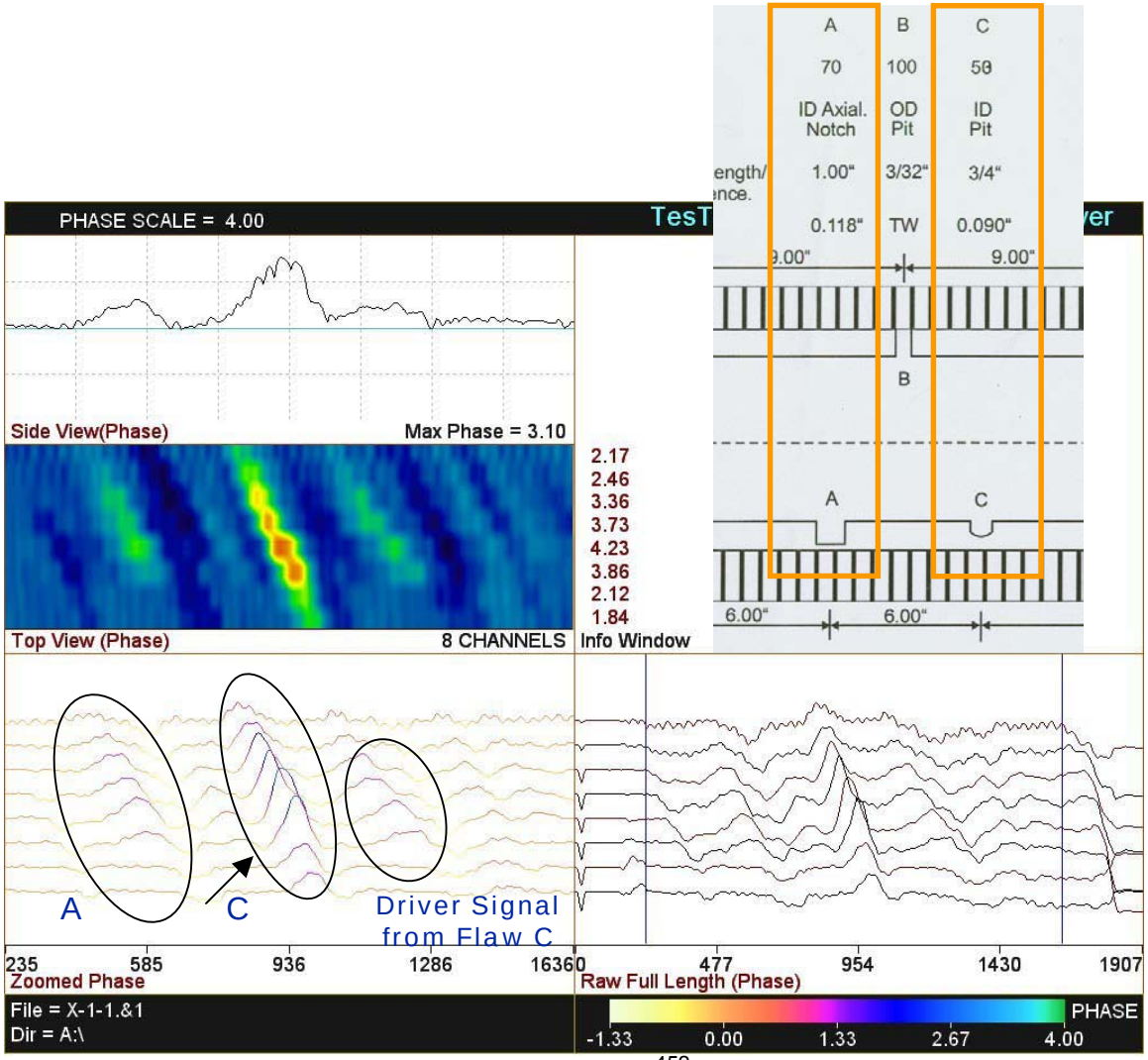


8-Channel Signal Output – Flaws B, D, E, & G

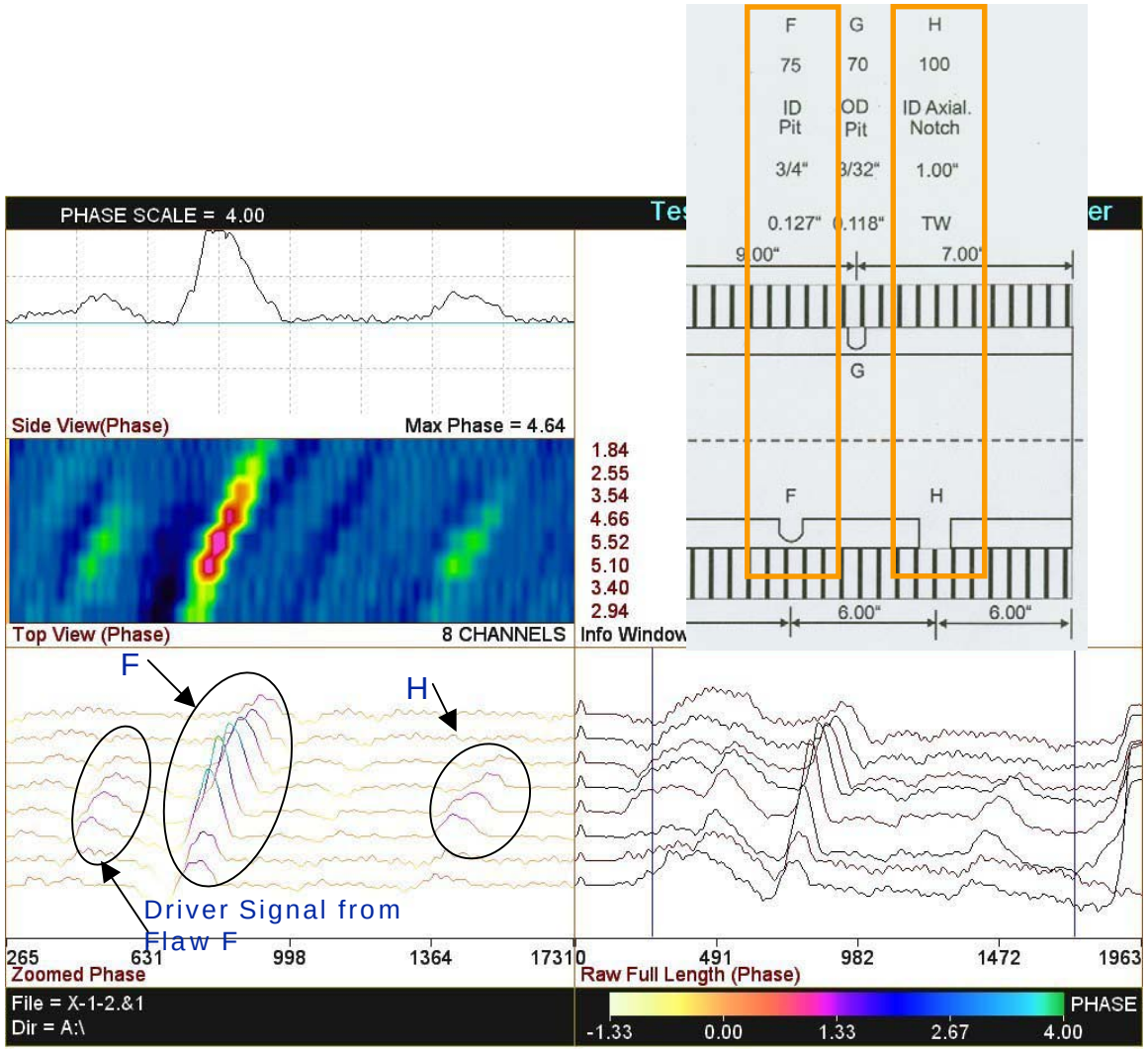




8-Channel Signal Output – Flaws A & C



8-Channel Signal Output – Flaws F & H

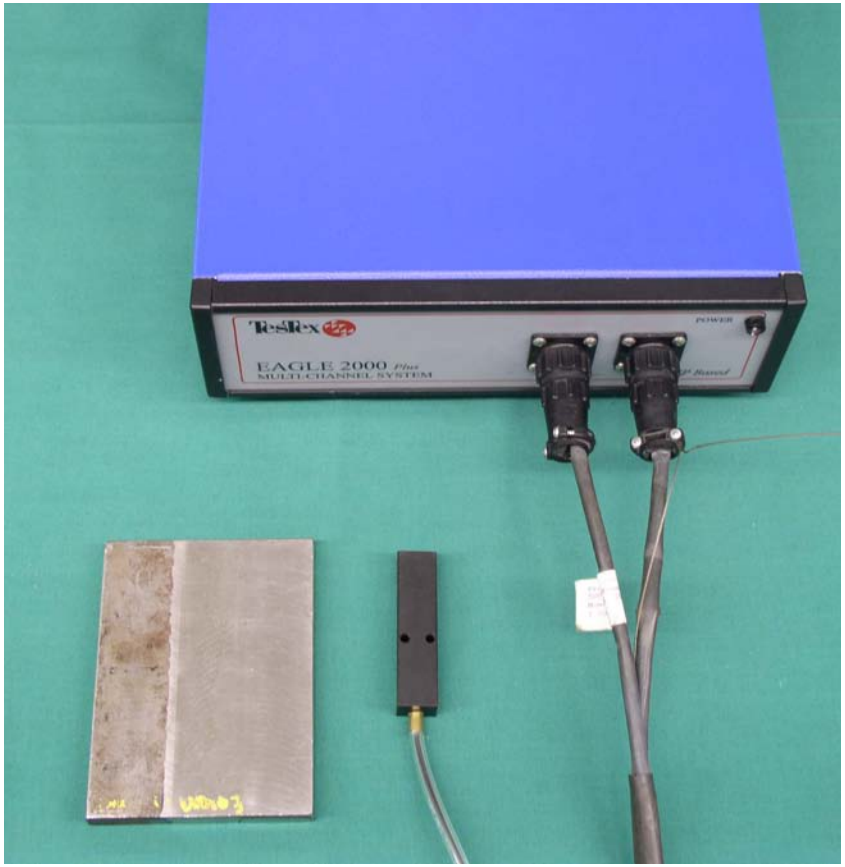


Observation on LFET

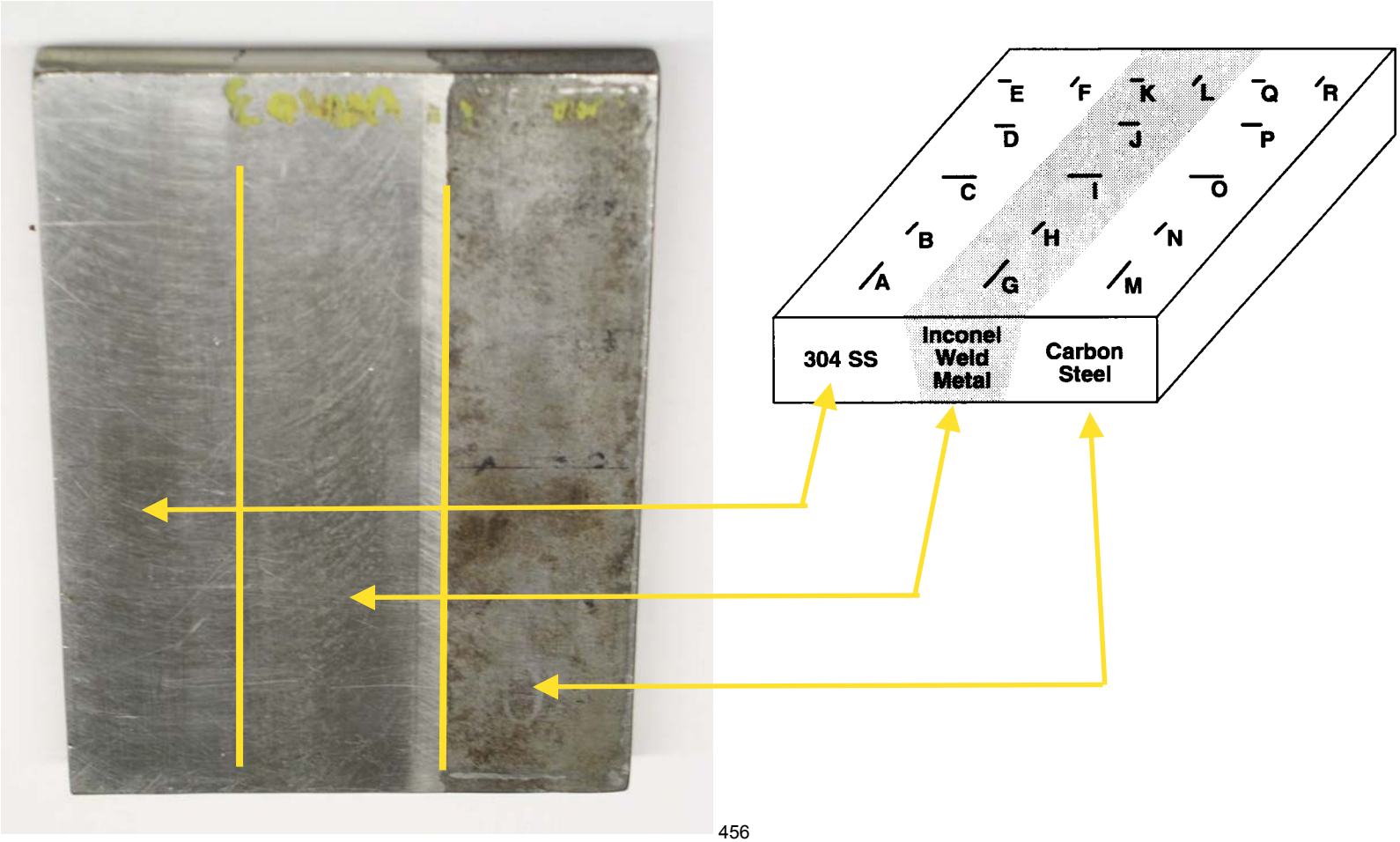
- Good screening tool
- Sensitive to both horizontal and vertical flaw orientations
- Detection is volume wall-loss dependent and not flaw depth dependent
- No flaw sizing was attempted
- Scanning allows C-scan plot of tested areas by indicating presence/absence of tubing flaws

Balanced (Null)-Probe for Testing Surface-connected Flaws

- Hawkeye Multiple Frequency, Multi-Channel Instrument
- Balanced or Self-Compensating Differential Square Probe – 5/8” by 5/8”
- Operating Frequencies
  - Carbon Steel – 950 Hz
  - Inconel/Stainless – 12 KHz
- Applicable to both Ferromagnetic and Nonmagnetic Materials



Dissimilar Metal Weld Plate Sample EDM Notches Squeezed Closed (CIP)



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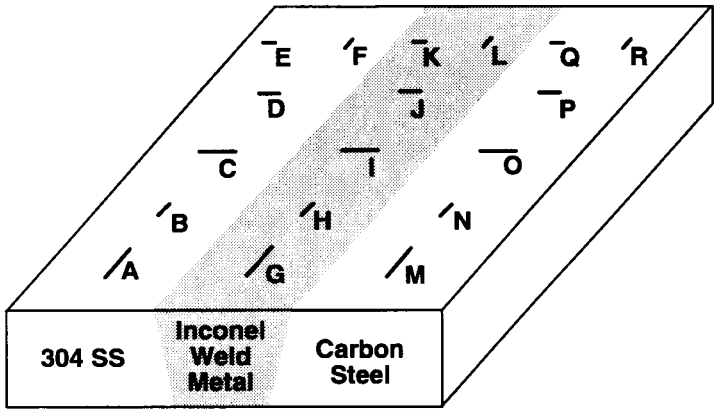
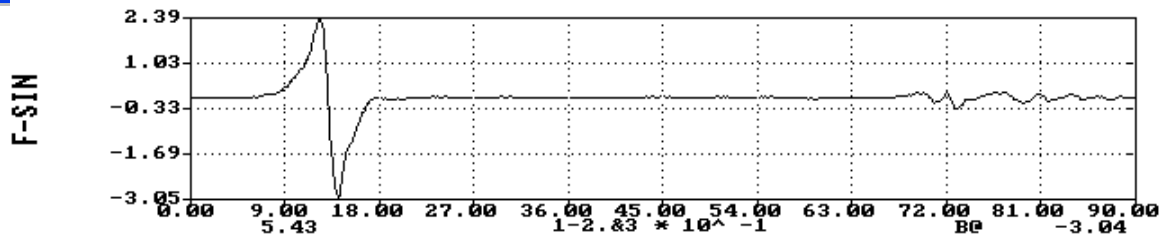
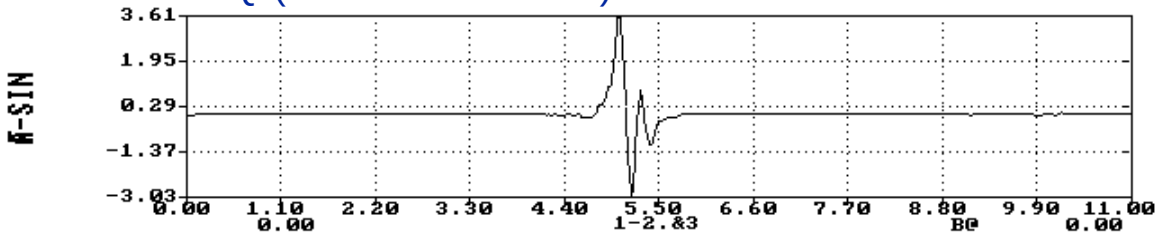
Balanced Probe Output
EDM Notches - Carbon Steel

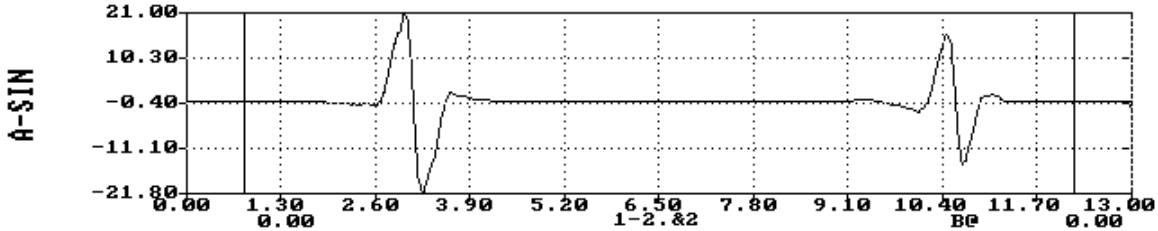




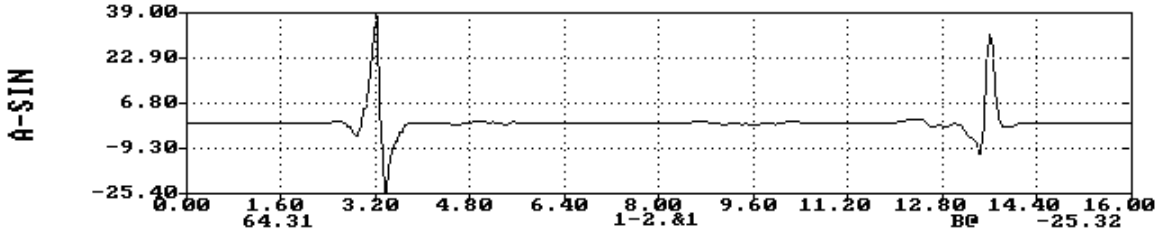
Q (0.062” x 0.020”)



R (0.062” x 0.020”)

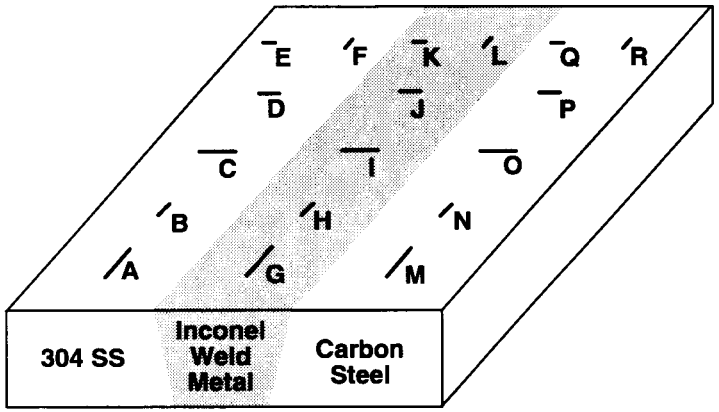


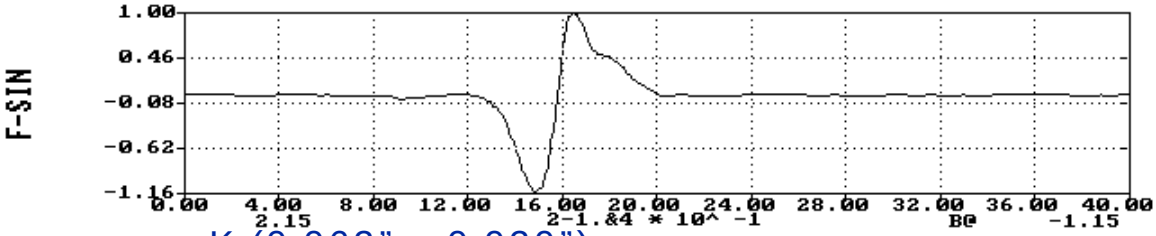
O (0.250” x 0.040”) and P (0.125” x 0.020”)



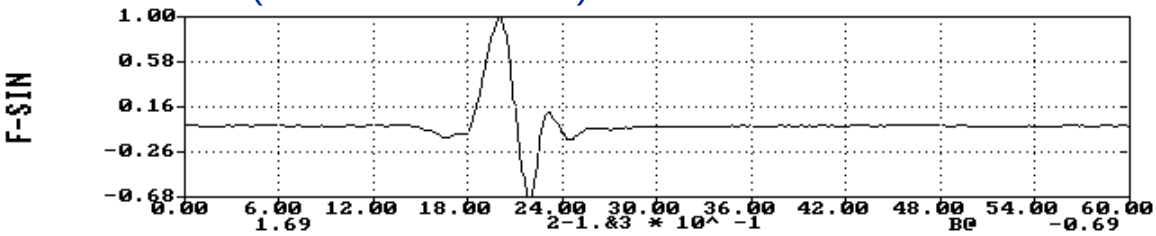
M (0.250” x 0.040”) and N (0.125” x 0.020”)

Balanced Probe Output
EDM Notches – Inconel 182 Weld

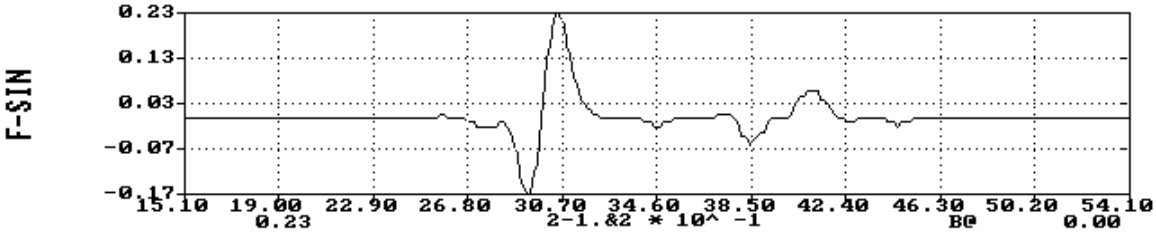




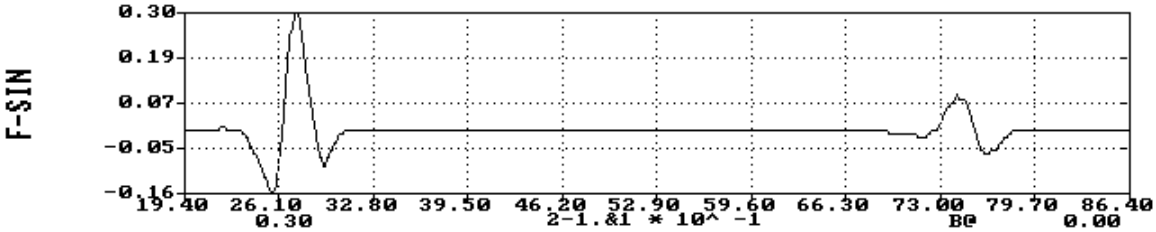
K (0.062” x 0.020”)



L (0.062” x 0.020”)



I (0.250” x 0.040”) and J (0.125” x 0.020”)



G (0.250” x 0.040”) and H (0.125” x 0.020”)

Observation of Balanced Probe performance

- Allows equal sensitivity to both ferromagnetic and non-magnetic tubing materials by changing operating frequency
- Need additional validation on as-welded tube samples
- Either amplitude or phase information can be used to estimate flaw depths

Through-Fin Inspection System for HRSGs (T-FISH) by Aptec

- Pulsed Eddy Current Testing
- 2.25 inch Wide Footprint
- ~10 Seconds per Measurement Point

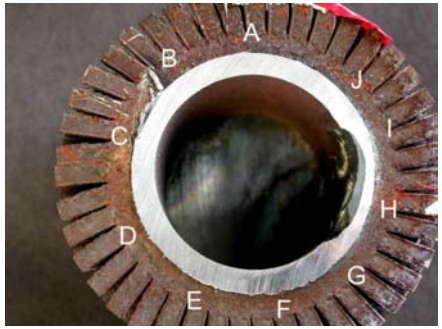
Test Samples

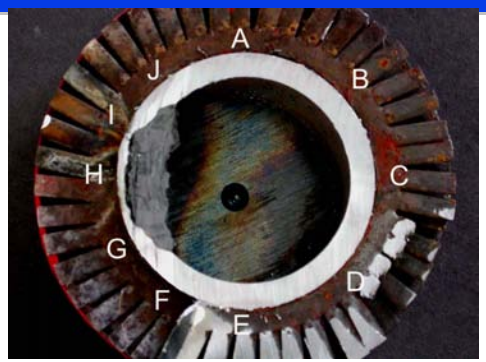
- Conducted Blind Test on 2 HP Evaporator Tubes
- 2 inch OD Carbon Steel / Ferritic Fins
- 1 Good Tube and 1 With Under Deposit Corrosion Damage after 1 Year of Service

ID Wall Thinning

No Defect
Good Tube

Preliminary Test Results

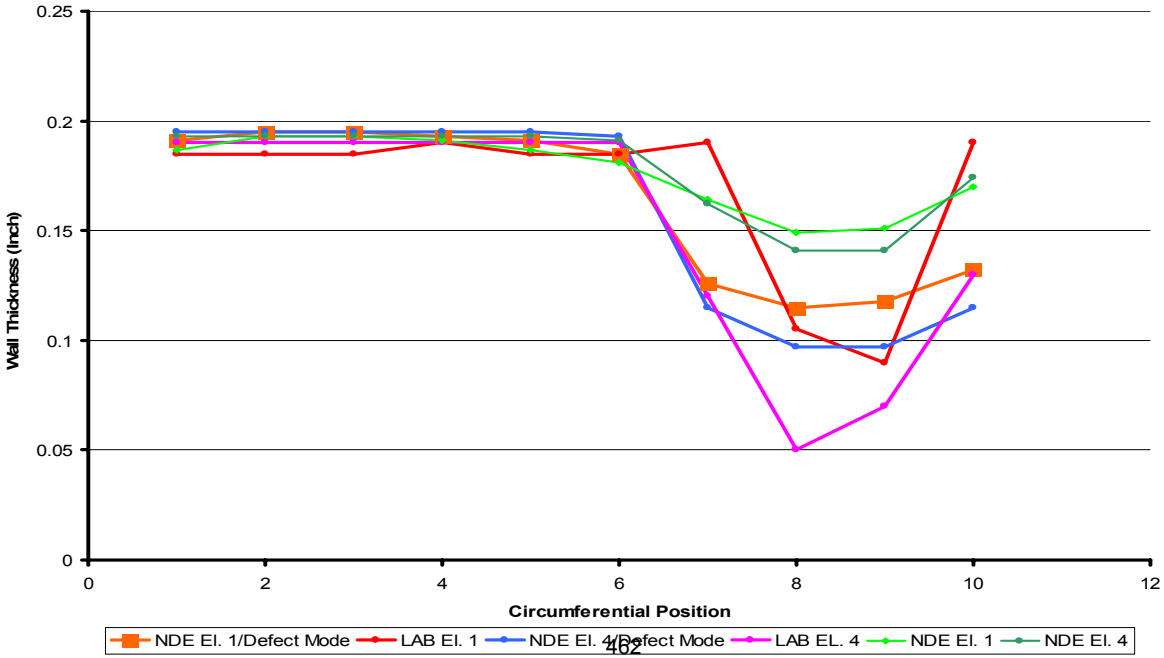




HRSG Tube Thickness NDE Through Fins
Under-deposit Corrosion Sample
February 2004

Elevation #1

Elevation #4



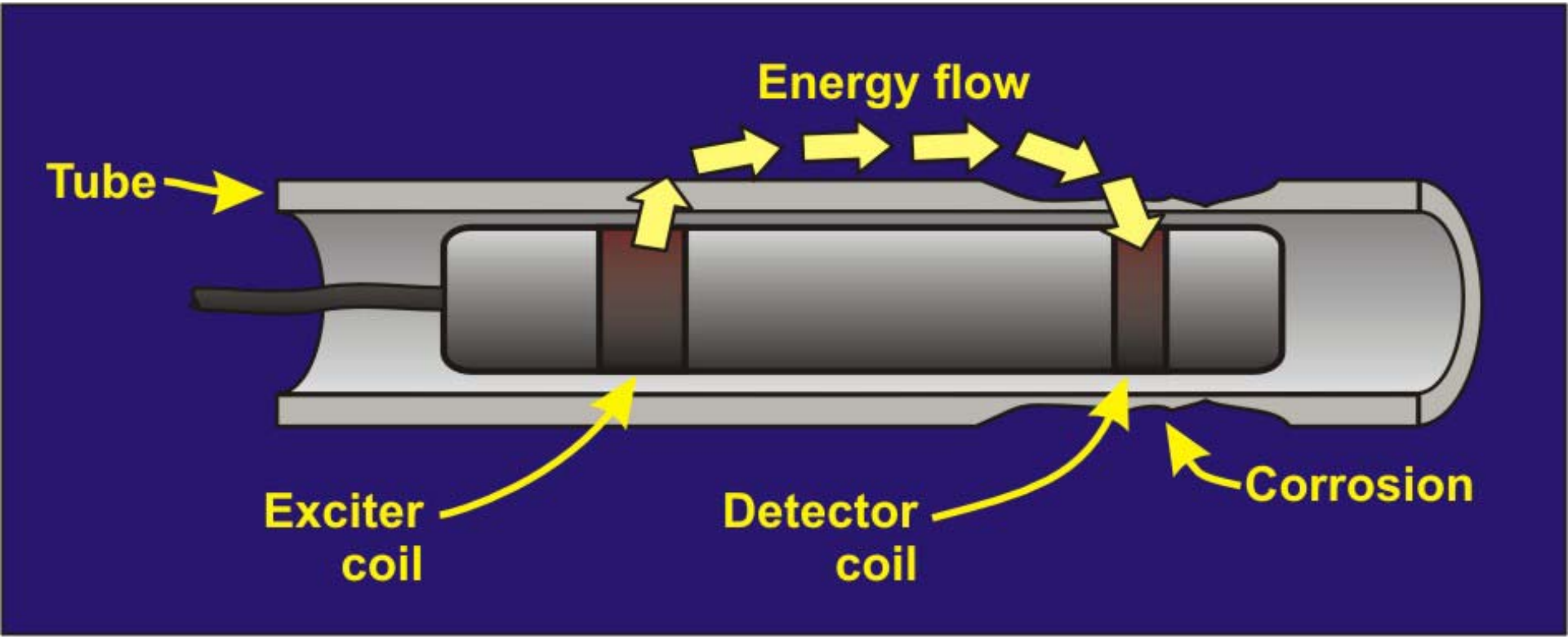
Observation

- Effective screening tool
- Mass of ferritic fins dilute signals, causing under-deposit corrosion to be under-estimated
- Austenitic fins transparent to signal
- Limited access to HRSGs
- Averaged wall thickness provided
- Flaw depth sizing possible with either amplitude or zero cross-over delay time information

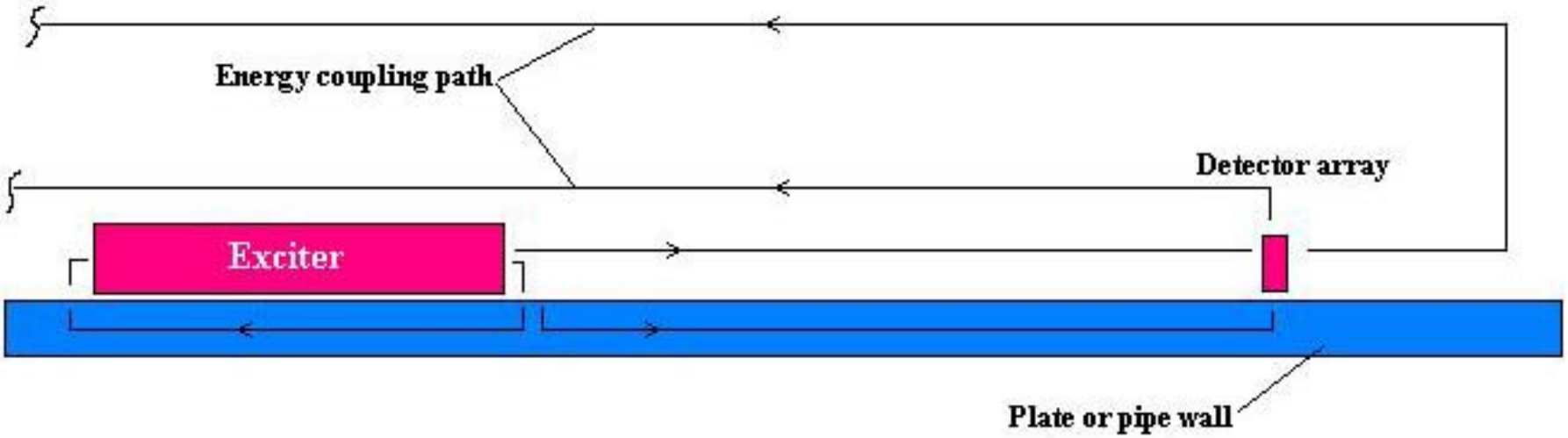
Ferroscope System

- Remote-field technology
- 4 Voltage Planes and 4 strip charts, including color maps
- Semi-automatic data analysis and reporting
- ASTM Standard Practice E2096-00 compliant
- Inspect pipes from inside or outside the pipe or tube
- MIX and Filter signals to eliminate unwanted parameters

Basic Internal RFT Probe



External RFT Schematic

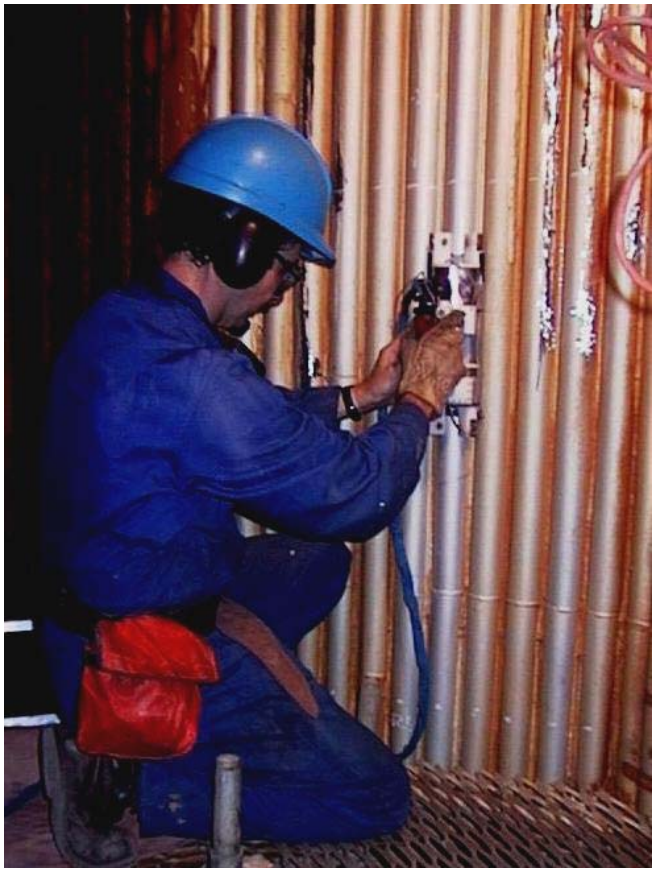


Energy couples into the plate or pipe wall, taking the path of least reluctance. The energy at the detector array is comprised of direct and indirect components

Waterwall Tube Inspection: Tube Condition Assessment

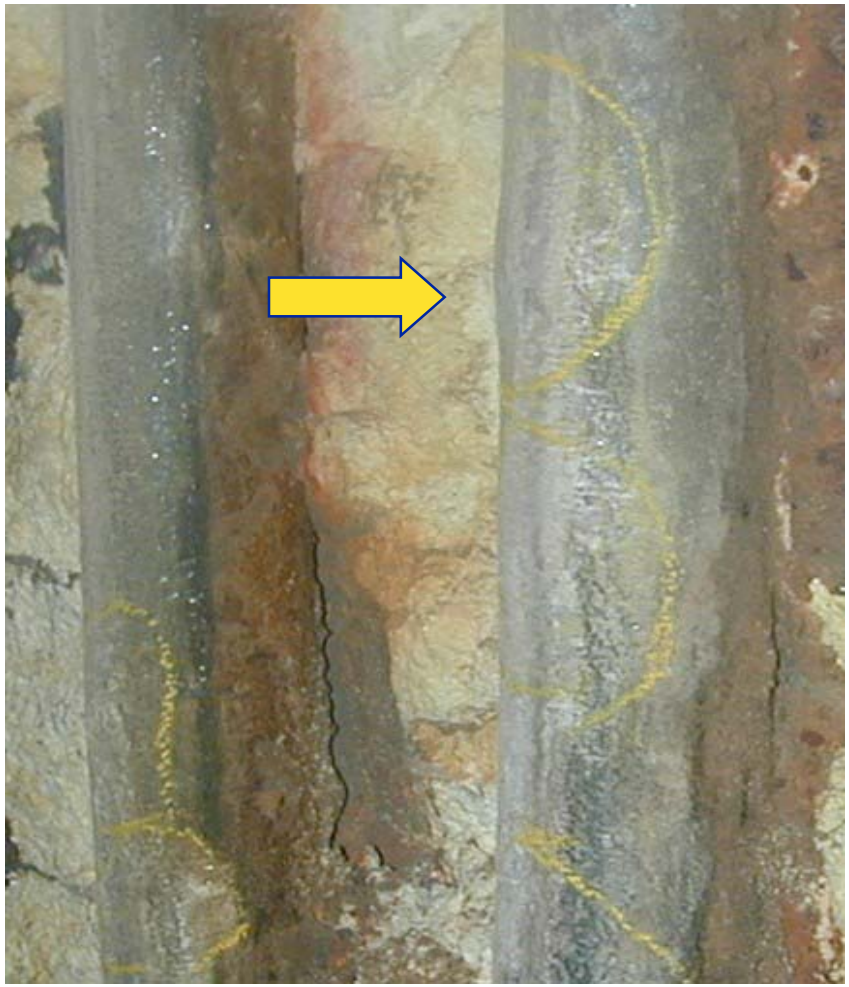
- Types of damage forms identified
  - Internal pitting
  - Hydrogen damage
  - Thermal fatigue
  - Blisters
- All forms of damage types can be detected and sized using a Ferroscope
- 1/8” diameter, 50% deep, FBH detectable

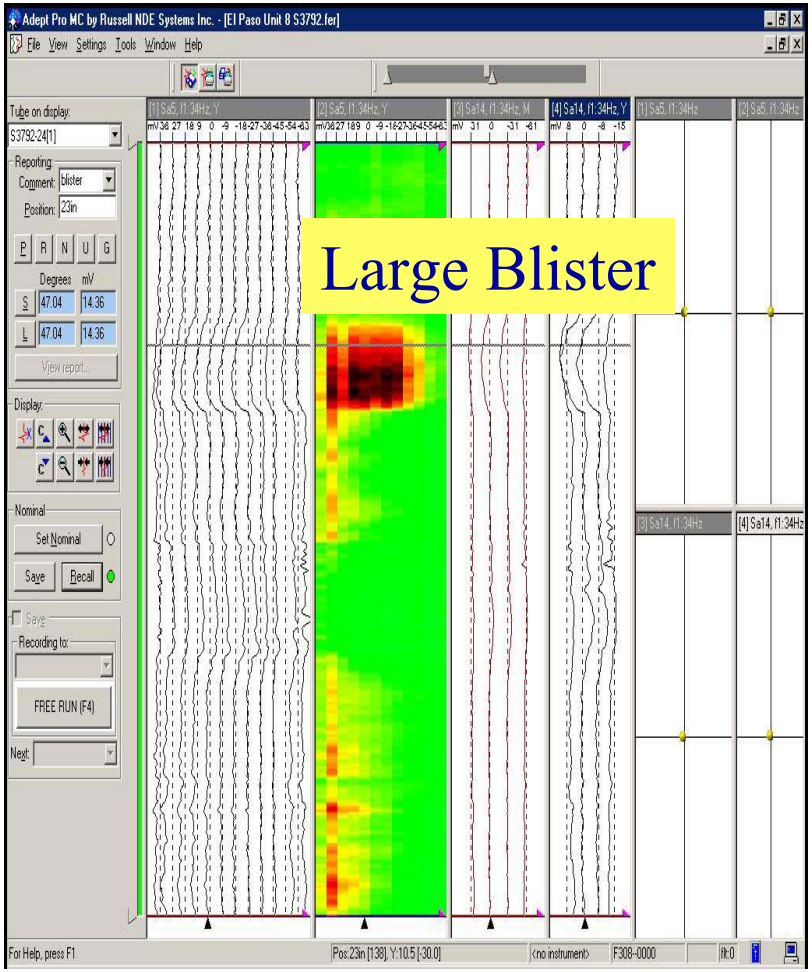
Waterwall OD Inspection



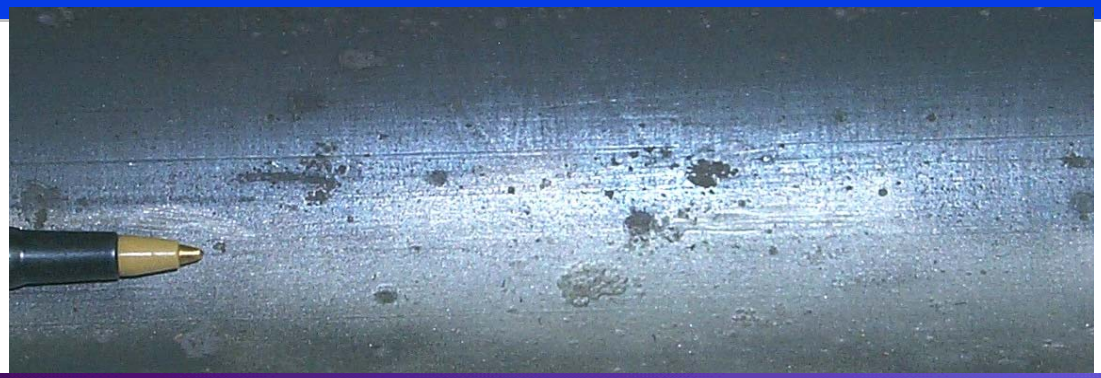
External “E-PIT” probe can inspect one to four tubes at a time at speeds of up to 10’/min

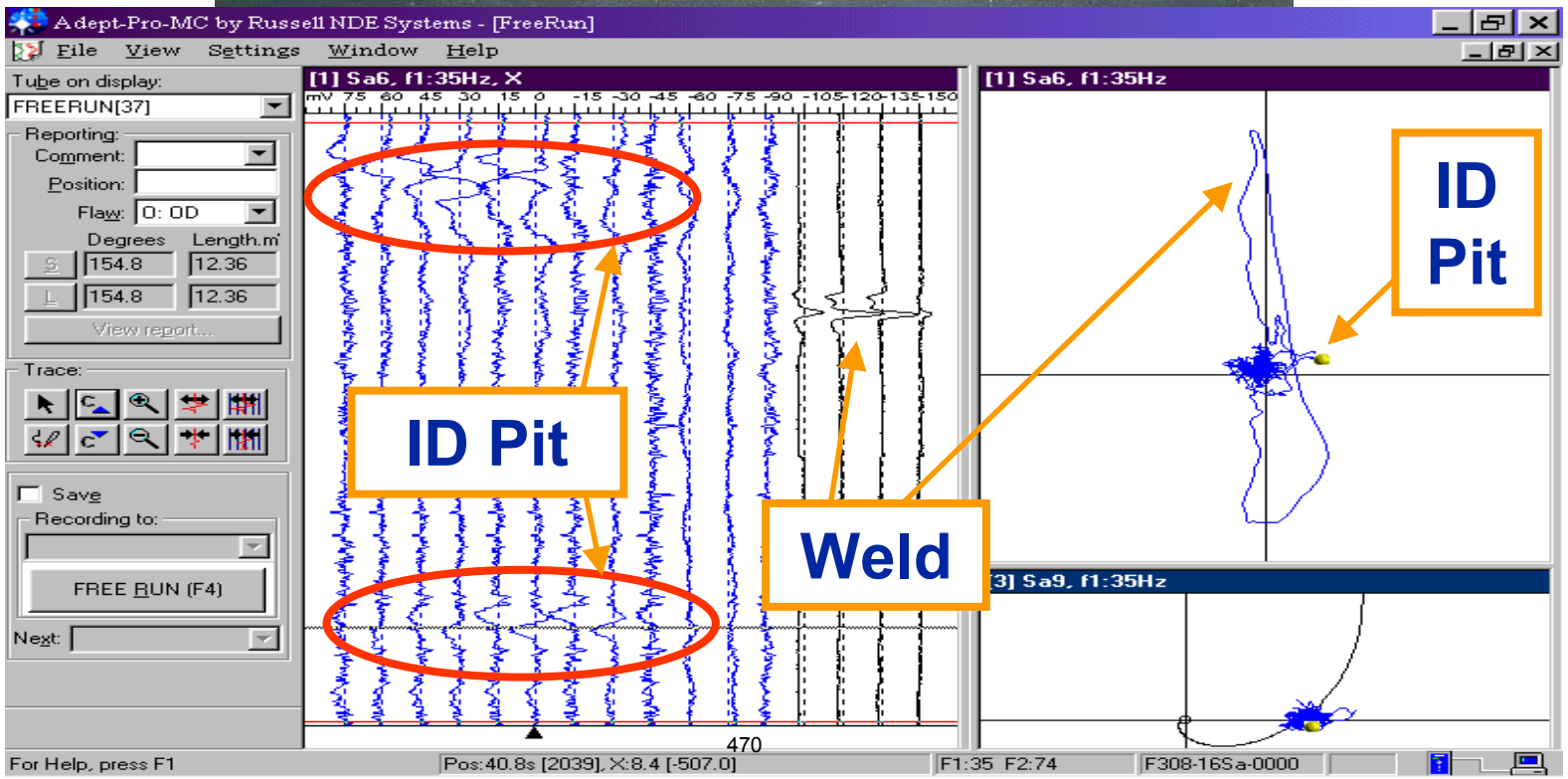
Blisters



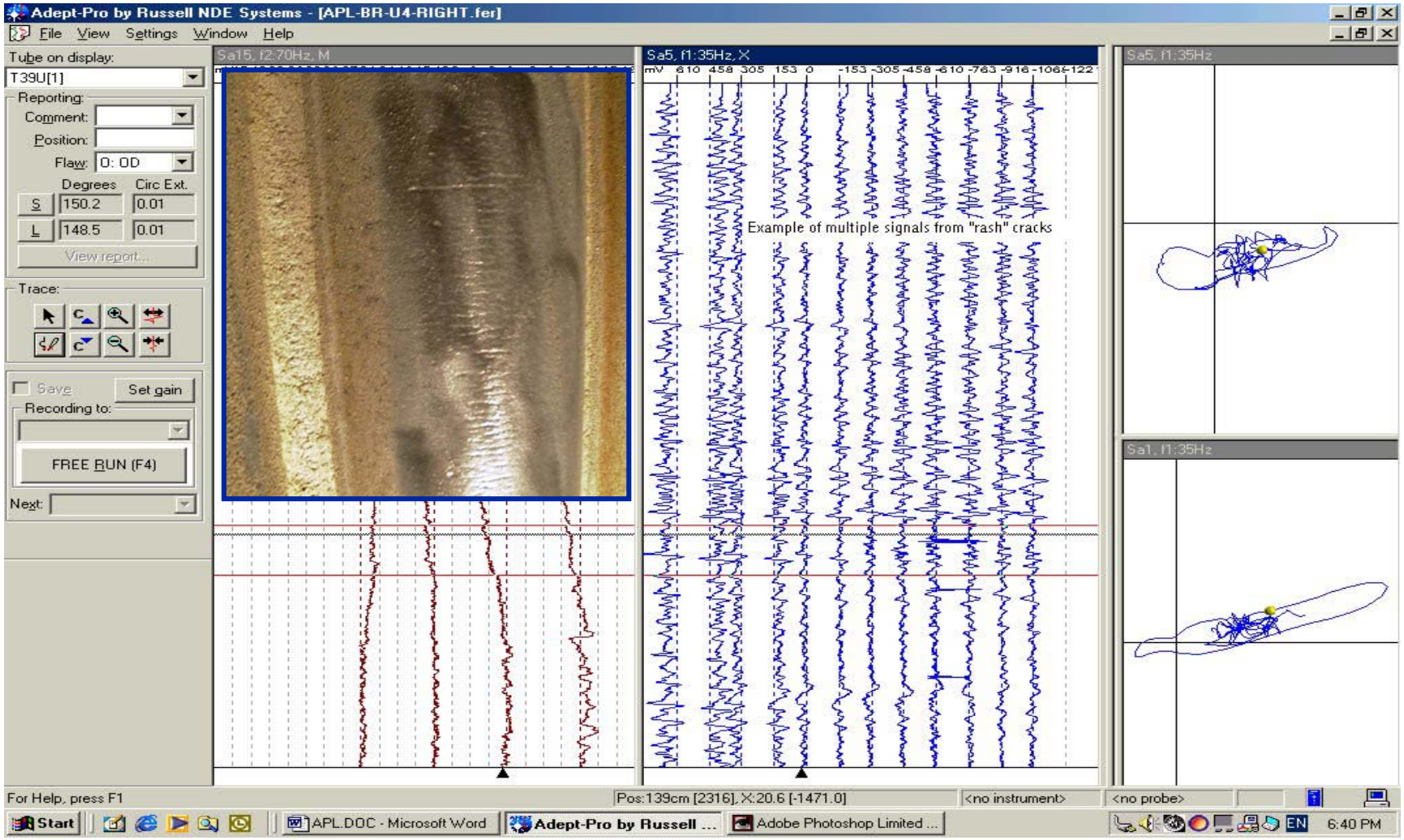

Adept Pro MC by Russell NDE Systems Inc. - [El Paso Unit 8 S3792.fer]
File View Settings Tools Window Help
Tube on display
S3792-24[1]
Reporting
Comment: blister
Position: 23in
Degrees mV
View report...
Display
Nominal
Set Nominal
Save
Recall
Recording to:
FREE RUN (F4)
Next:
Large Blister
For Help, press F1

ID Pits

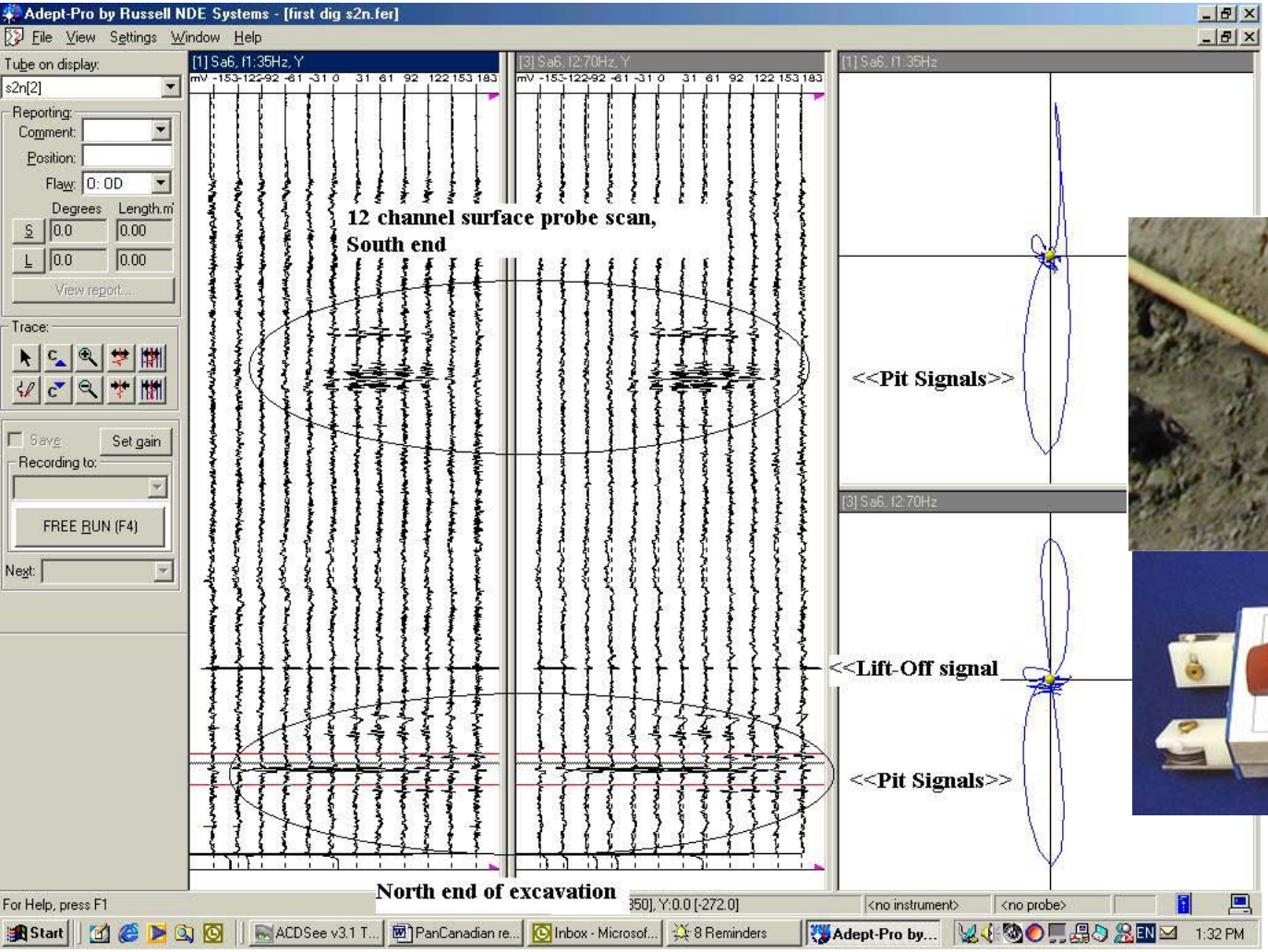



Adept-Pro-MC by Russell NDE Systems - [FreeRun]
File View Settings Window Help
Tube on display:
FREERUN[37]
Reporting:
Comment:
Position:
Flaw: 0: OD
Degrees Length.m
S 154.8 12.36
L 154.8 12.36
View report...
Trace:
Save
Recording to:
FREE RUN (F4)
Next:
[1] Sa6, f1:35Hz, X
mV 75 60 45 30 15 0 -15 -30 -45 -60 -75 -90 -105 -120 -135 -150
ID Pit
Weld
470
[1] Sa6, f1:35Hz
ID Pit
[3] Sa9, f1:35Hz
For Help, press F1
Pos:40.8s [2039], X:8.4 [-507.0]
F1:35 F2:74
F308-16Sa-0000

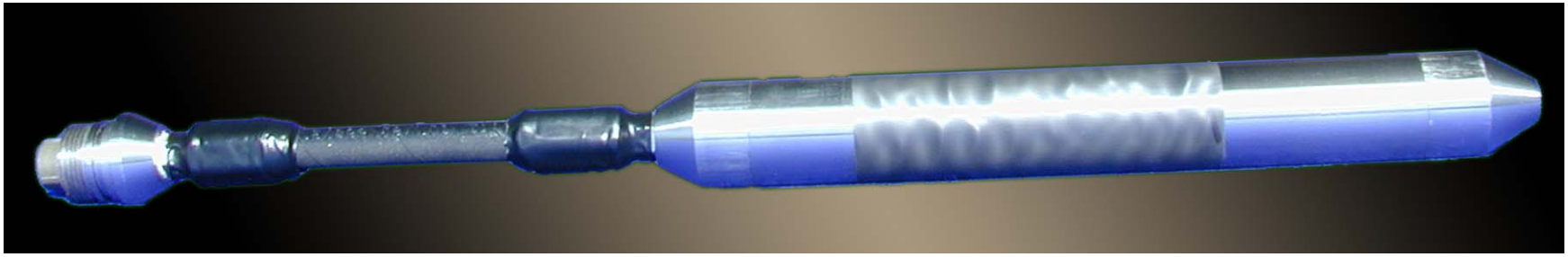
Thermal Fatigue Cracking



Another ID Pit Detection

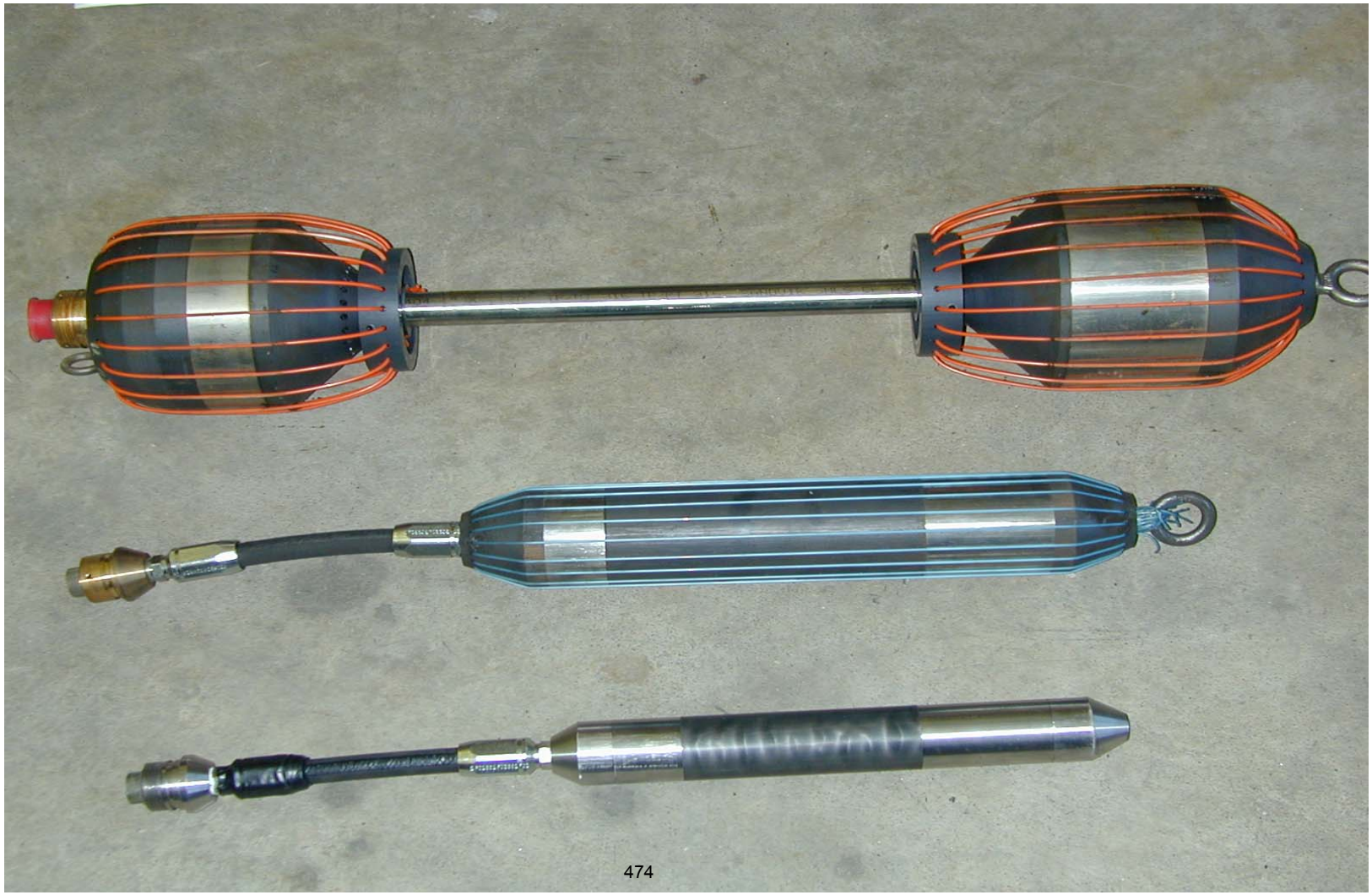


I-Pit Internal Pipe Inspection Tools

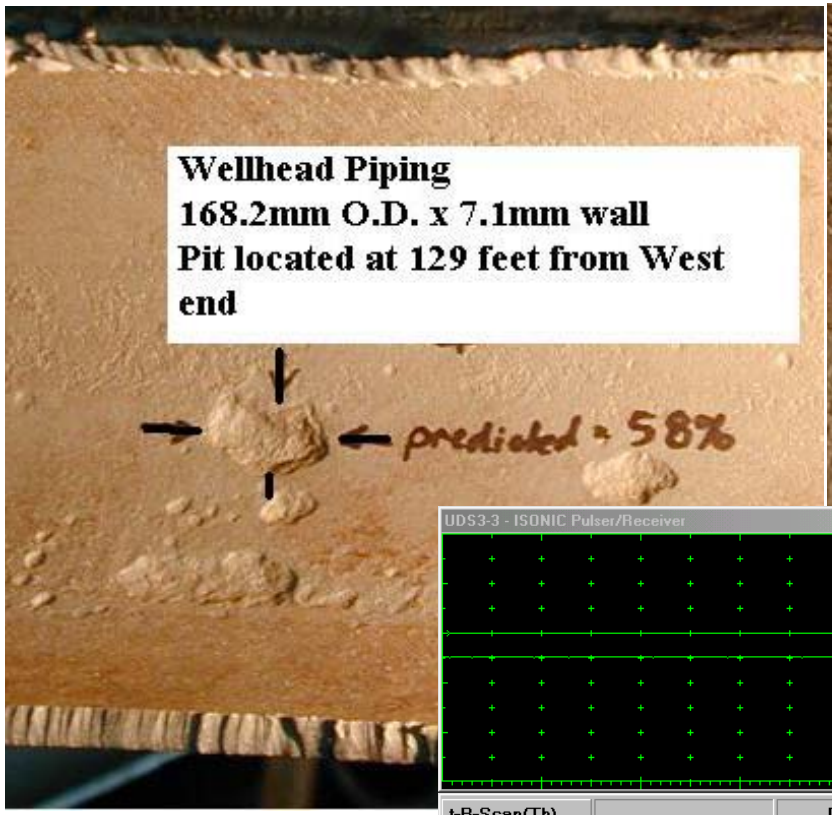


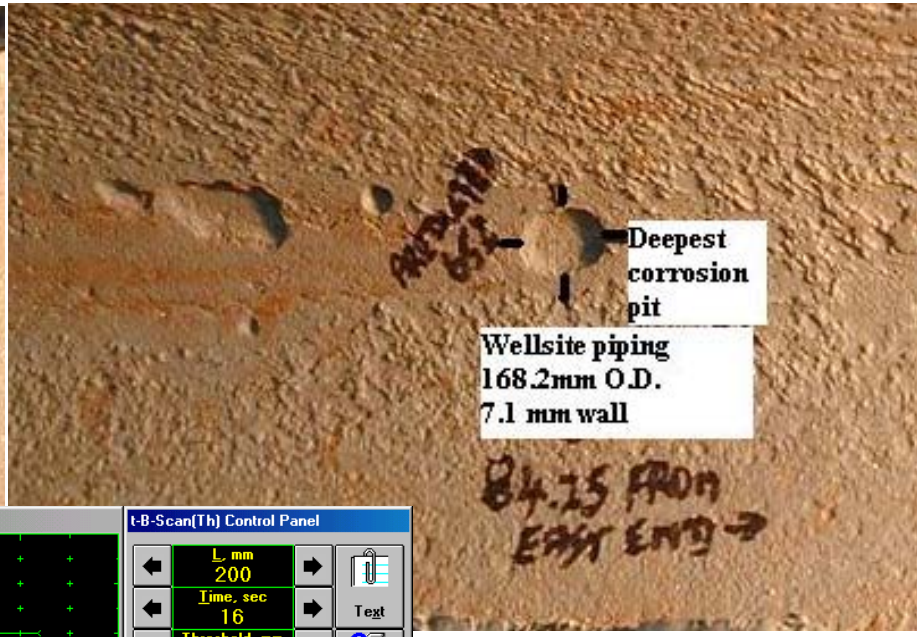
- Internally inspect pipelines 2” to 8”
- Detect/size internal or external pits
- Multi-channel tools – one driver with multiple array receiver coils
- Inspect up to 600’ from one insertion point
- Water resistant and rugged

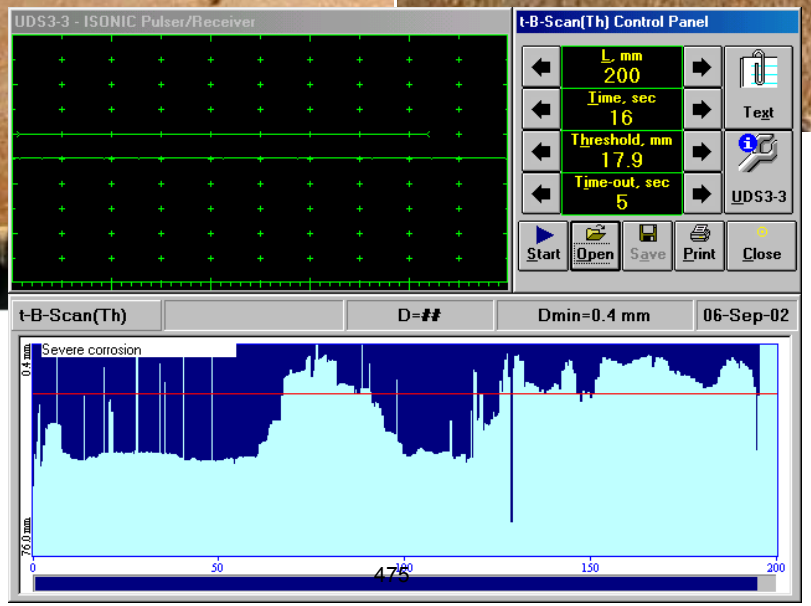
I-Pit Sensors



ID Pit Detection







Observation on ID/OD Ferroscope Applications

- Offer more “coverage” than spot ultra-sonic thickness readings
- Automation of scan speed and distance encoding results in more reliable data & data presentation
- Multiple array receiver coils necessary to detect small-diameter pits
- Smaller inspection crew & faster inspection results
- Flaw depth sizing possible using appropriate calibration curves

Summary

- Access to HRSG is still a challenging issue
- Review of NDE technology showed promising test results from both OD and ID sides
- Flaw detection is currently better accomplished than flaw sizing
- More realistic samples are needed for technique validation

SESSION 12: Remaining Life Techniques

Chairman: D. Gandy, EPRI

Financial Risk Optimization: Application Example in Integrated Life Management of a High Temperature Boiler Tube Component

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I. Introduction

Boiler engineers are asked many times to recommend partial replacements in high temperature tube components. Being able to determine the number of tubes to be replaced and when this replacement needs to be take place to maximize the benefit to the corporation can be of great support to the boiler engineer for his recommendation.

This paper describes integrated life management steps for high temperature boiler tube components from the inspection results to Probabilistic Remaining Life Analysis to Financial Risk Optimization (FRO). This assessment addresses the need engineers have to express the engineering condition or condition assessment of the component in probability of failure versus time and ultimately in financial risk. The probability of failure versus time, income related factors such as consequential cost of failure, as well as partial replacement cost for the tube component are important inputs in any financial risk decision analysis. The FRO integrates the condition of the component with risk considerations through financial/decision analysis to provide the financial optimum number of tubes to be replaced and the time they need to be replaced.

II. Approach

A. Inspection

The first step is to establish the present damage state of the high temperature tubing component. This inspection needs to include remaining tube wall thickness to assist in establishing tube wall stress and internal oxide thickness for establishing average tube metal temperature for each tube inspected. At SI this inspection is performed with the TestPro inspection system.

B. Remaining Life Analysis

LIFECODE calculates remaining life of high temperature an individual tube using principals developed by D. N. French in hid 1983 textbook, “Metallurgical Failures in Fossil Fired Boilers”. The major inputs are initial tube size dimensions, operating pressure and time, internal oxide scale thickness, current wall thickness and material properties (taken from ASTM data). The change in wall thickness over time (linear) provides an ever increasing stress and the build up of the insulating internal oxide provides an estimate of temperature increase over time. The values of stress and temperature are recalculated for every annual time period, depending on the

projected capacity factor or the unit, and the resultant creep life fraction is estimated for each period and accumulated. When the value of life fraction reaches 1, it is assumed that creep life is exhausted and tube failure occurs.

C. Probabilistic Remaining Life Analysis

An enhancement to LIFECODE is Probabilistic LIFECODE. This enhancement performs a probability of failure versus time of each tube inspected through Monte Carlo analysis. The random variables for this analysis are material properties and tube metal temperature. Other variables can be randomized. To input the FRO the probability of failure versus time for each tube under consideration for replacement and is inspected for ID oxide scale and remaining wall thickness.

D. Number of Tubes To Be Replaced

Another enhancement to LIFECODE is Financial Risk Optimization (FRO). The first optimization in Probabilistic LIFECODE with FRO is the optimization of the financial benefit through the selection of the number of tubes to be replaced in the partial replacement.

E. Year to Replace Tubes

The second optimization in Probabilistic LIFECODE with FRO is the optimization of the financial benefit through the selection of the year to perform the partial replacement of the optimum number of tubes.

III. Example

Two examples will illustrate the usefulness of this process. First consider a high temperature tube component that has severe problems. This particular component is one boiler of a twin 400 mW unit, with a 90% capacity factor, and a cost of $30 /mWh forced outage cost. The breaker to breaker time to replace a failed tube is 48 hours. The component has 164 tubes all of which have been inspected with the TestPro system for ID scale thickness and remaining wall thickness. The optimization of number of tubes to be replaced indicates that the maximum benefit for the replacement cost of $2,000 per tube, and $2,000,000 fixed cost to access the tube section, is achieved with a replacement of 97 tubes, Figure 2. That will result with a before and after tube replacement probability of failure versus year curve shown in Figure 1. Lastly Figure 3 shows the NPV versus replacement versus year curve indicating the maximum benefit year to replace these 97 tubes is year one.

The second example to consider is a component that has limited problems. This component is in a 200 mW unit, with a 34% capacity factor, that has 113 tubes all of which have been inspected with the TestPro system for ID scale thickness and remaining wall thickness. The optimization of number of tubes to be replaced indicates that the maximum benefit for the replacement cost of $3,000 per tube is achieved with a replacement of 4 tubes, Figure 5. This will result with a before and after tube replacement probability of failure versus year curve shown in Figure 4.

Figure 6 shows the NPV versus replacement versus year curve indicating the maximum benefit year to replace this tube is a 4 year delay.

The larger NPV created for the severe problem component versus the small NPV for the limited problem component is a function of the difference between the present situation versus after replacement probability of failure curves minus the cost of tube replacement as well as the much larger projected capacity factor for the unit with the severe problem. Note that the NPV's for this are can be quite large because of the forced outage cost created over several years.

IV. Conclusions

An integrated life management process for high temperature tube components consisting of:

A. Wall and internal oxide thickness for each tube to define present state,
B. A remaining life analysis model for projection of future tube condition,
C. Probability of failure versus time curves for each tube from probabilistic analysis,
D. A process for combining groups of individual tube probability of failure versus time curves,
C. A financial/decision analysis process to determine the maximum benefit number of tubes to be replaced, and
D. The same financial/decision analysis process to determine the maximum benefit year for a partial tube replacement,

This process can be of great support to the boiler engineer that needs to make recommendations on the extent of partial replacements and when it needs to take place.

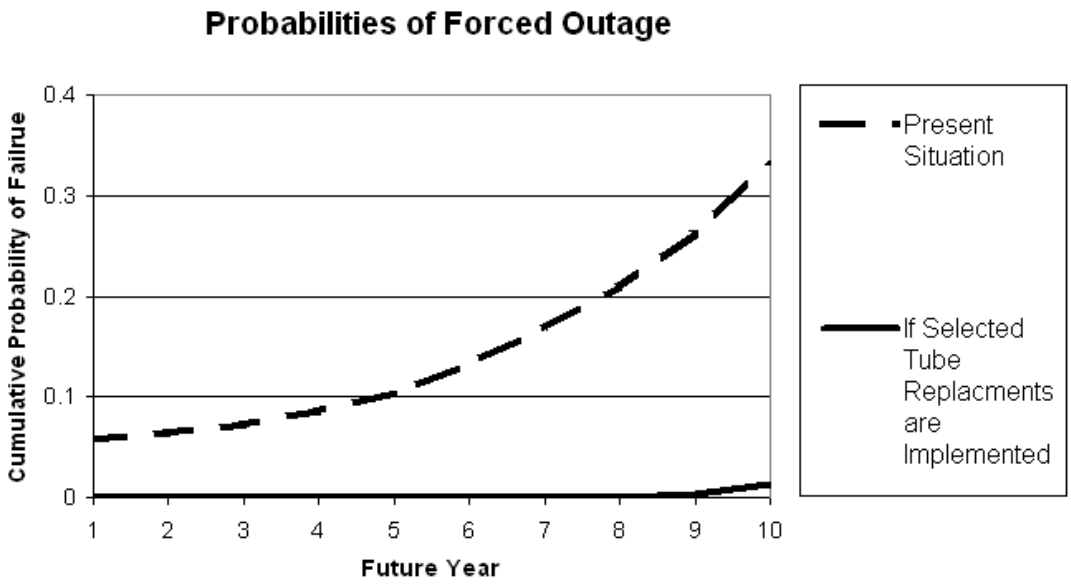

Figure 1. The Probability of Failure versus Year Curve For High Temperature Tube Component With A Severe Problem

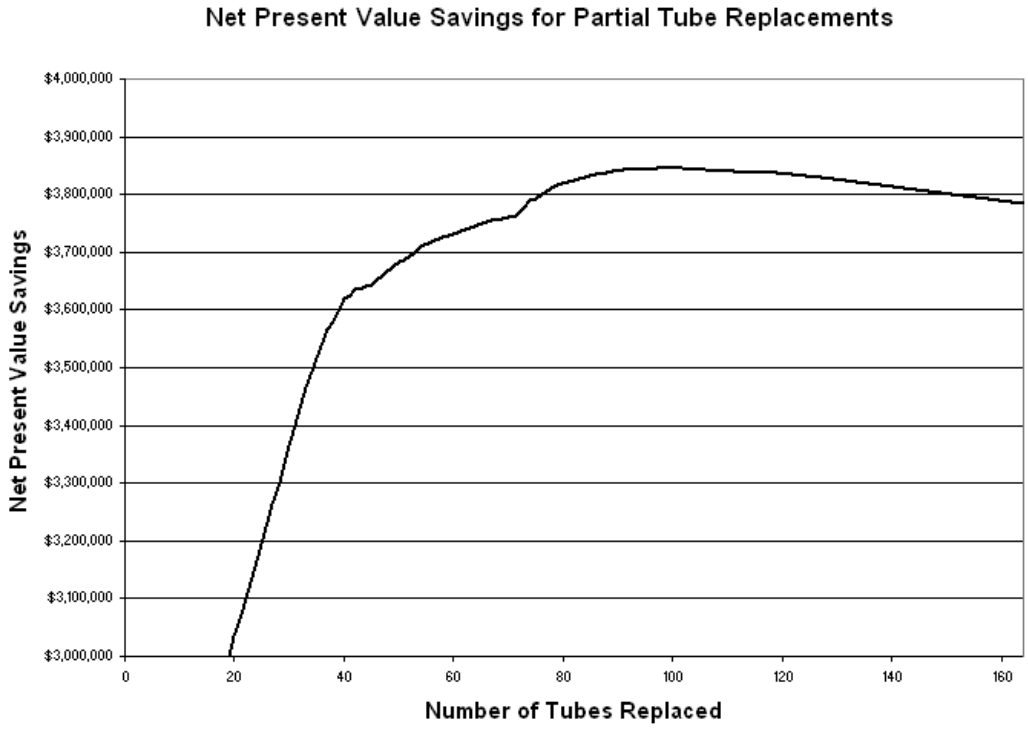

Figure 2. The NPV versus Number of Tubes To Be Replace Curve For A High Temperature Component With A Severe Problem with an NPV maximum at 97 tubes

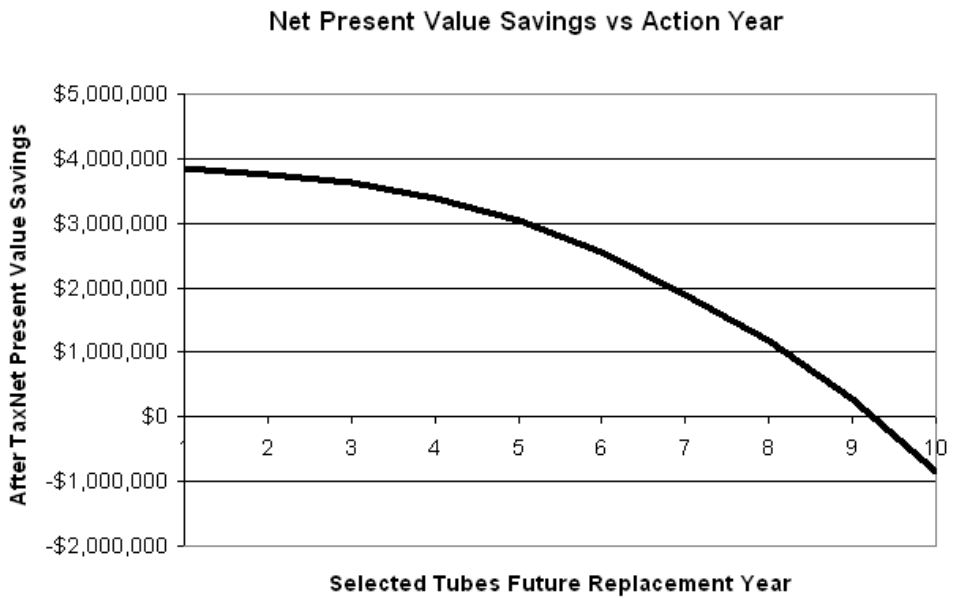

Figure 3. The NPV versus Replacement Year Curve For The 97 of 164 Tubes To Be Replaced For A High Temperature Component With A Severe Problem

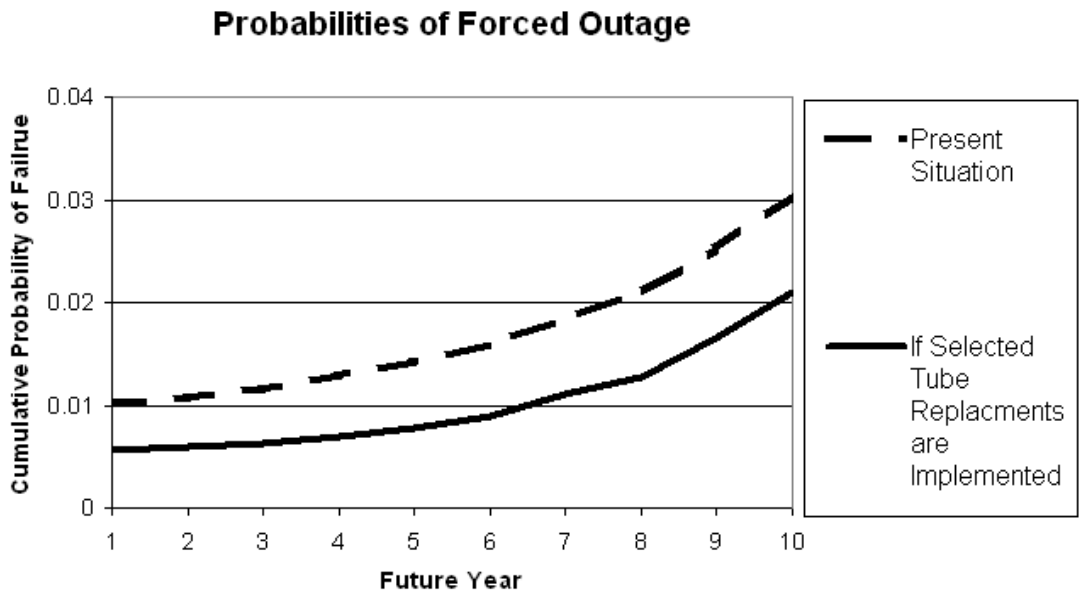

Figure 4. The Probability of Failure versus Year Curve For High Temperature Tube Component With A Limited Problem

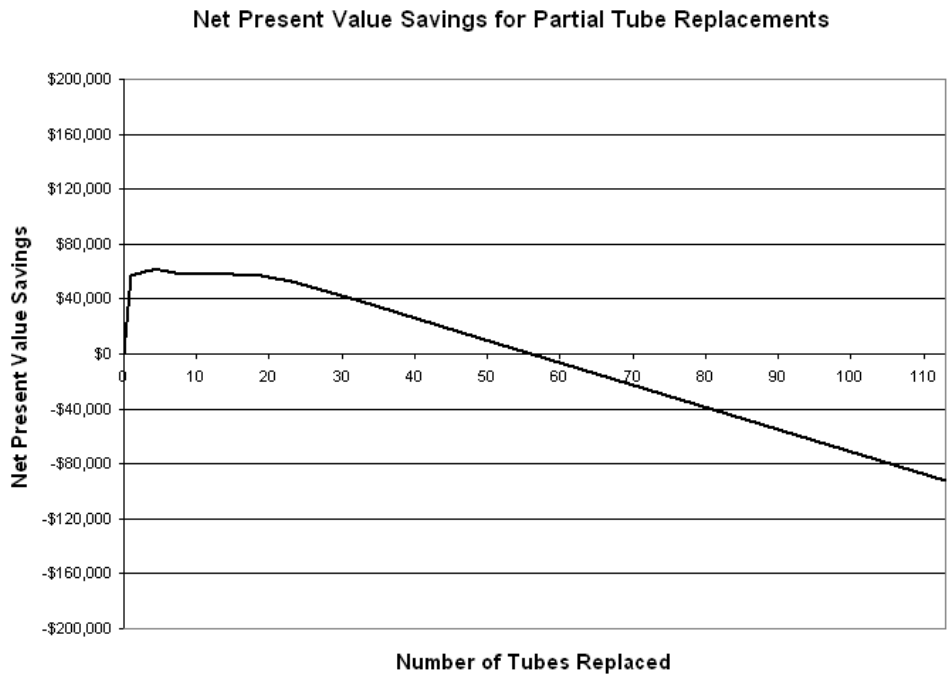

Figure 5. The NPV versus Number of Tubes To Be Replace Curve For A High Temperature Component With A Limited Problem with an NPV maximum at 4 tubes.

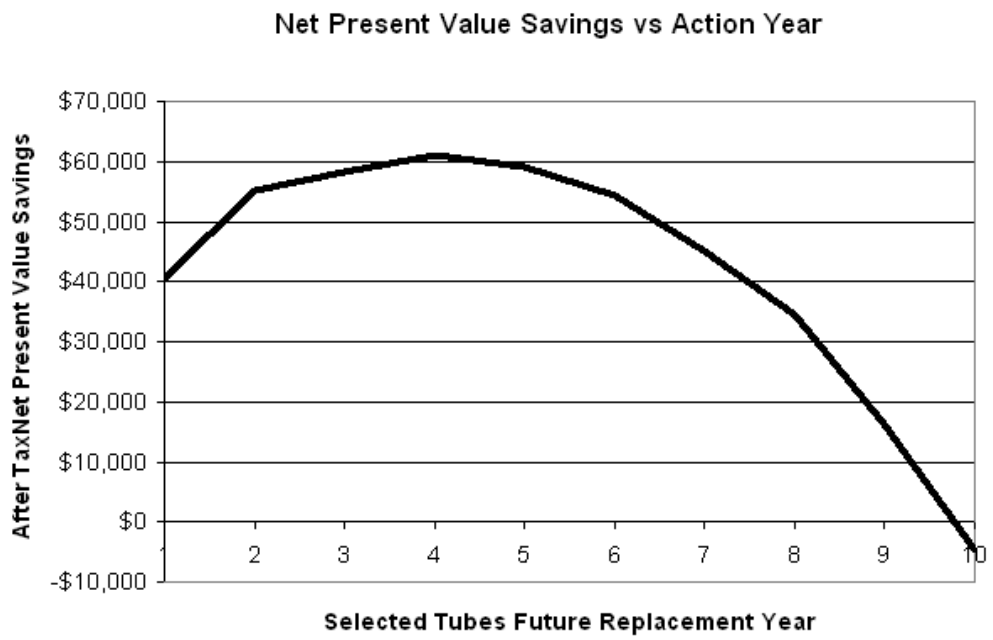

Figure 6. The NPV versus Replacement Year Curve For 4 Tubes To Be Replaced For A High Temperature Component With A Limited Problem

LIFE CYCLE OF A REHEATER TUBE BANK

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ABSTRACT

Routine monitoring of tube banks at statutory overhauls represents a key element of any long-term maintenance strategy, particularly should a Station experience changes in fuel and/or operating regime. When a problem is recognised, and correctly diagnosed, ameliorative measures can be implemented. However, policing the problem through the fitment of inserts tempers rather than eliminates the failure threat and ultimately the level of inspection and maintenance becomes untenable such that selective or wholesale stage refurbishment becomes the most cost effective solution.

This paper explores a selection of the damage mechanisms, and their root causes, that have affected the final reheater tube banks in modern coal fired power plant. Some of the practices and techniques that have been successfully employed in managing steam tube bank integrity are discussed, extending from the provisional condition monitoring assessments through to the determination of optimum stage replacement options. The achievement of greater stage lifetimes through tube material upgrades and heating surface reconfiguration is also considered. Whilst the emphasis is very much on UK plant, most of the issues covered are equally applicable to boilers worldwide.

INTRODUCTION

In common with all living organisms, engineering components and structures exhibit well defined life cycles, from conception on the designer's drawing board through increasingly high maintenance middle and old age and onto final decommissioning. Inevitably, therefore, this understanding extends to pendant reheater tube banks in large, contemporary coal-fired boilers.

The contemporary fleet of 500MW coal-fired boilers in the UK were built and commissioned in the late-1960s and early-1970s, with nominal design lives of 100,000 hours under base-load operation whilst firing indigenous fuels. Each manufacturer met these challenges with their favoured stage designs and tube arrangements, but all were grounded in engineering understanding gained some 5-10 years previously on smaller scale plant and employed materials contemporary to that time. Almost without exception, these boilers have now accumulated in excess of 200,000 hours service under mixed operating regimes and firing a more diverse fuel mix than anticipated four decades previous. Inevitably, therefore, integrity issues have meant that many of these boilers are now running with second and even third generation tube banks, often to improved designs and employing more exotic materials than their predecessors.

Based upon the broad experiences of engineers servicing the UK power industry, but with parallels internationally, this paper explores the 'life-cycle' concept as applied to a pendant reheater bank in a large, contemporary coal-fired boiler.

CONCEPTION; A STAGE IS BORN

Whether preceded by radiant wall, horizontal convective banks and/or pendant stages, the final stage reheater bank represents the final stage in the boiler circuit, almost invariably exposed to an onerous combination of high gas and metal temperatures and aggressive fireside environments. Towards achieving long-term pressure containment under such conditions whilst remaining within given economic constraints, the original stages were frequently crafted using a selection of tube sizes and available materials. Low alloy ferritic steels, nominally T11 and T22, would be favoured in the penthouse and upper pendant sections with 18%Cr/11%Ni stainless steel tubing being employed only where creep/fireside corrosion was considered likely to be an issue. In later life, this host of tube specifications would demand extensive stock-keeping to anticipate tube failures and incur a highly involved series of calculations in determining residual creep life.

Despite exposure to the same operating environment as the neighbouring final stages of superheat, the relatively lower operating pressure (580psi (40 bar)) means that the corresponding stages in the reheater circuit are constructed from significantly thinner wall tubing. As a consequence, the final reheat stage is rendered less tolerant to deviations from the long-term operating conditions originally envisaged by the designers. Such departures from ideality may derive from;

- **Inherent Characteristics**. Not all tubes are created equal; the burner configuration and header system design will afford the stage a pronounced thermal profile across the boiler width, differentials approaching 50°C potentially existing between corresponding tube paths in different elements with more subtle intra-element effects also in evidence. Furthermore, metal operating temperatures within the stage may be some 60-80F (40-50°C) above the nominal final steam outlet temperature (1055F (568°C)).

- **Fuel Chemistry**. Whilst the indigenous fuels have a perceived high corrosion potential, anticipating the corrosivity of specified fuel blend from its chemical constituents is an inexact science that is complicated by the prevailing local thermal and gaseous environments to which the tubes are exposed. Almost invariably, the actual corrosion rates exceed those predicted before the first fuel delivery is combusted.

- **Operational Regime Changes.** Fundamental changes in operating regime reflecting the commercial theatre of operation can dramatically exacerbate, or mitigate, the propensity for tube failures and associated downtime. In the UK, the advent of deregulation several decades after construction saw the coal-fired fleet experience a rapid transition to cyclic operation and the progressive introduction of more diverse fuel sources[1]. Against this background, environmental legislation heralded retrofit installation of low NO_x burners on all boilers in the late-1980s and early-1990s.

Deviations from the designers' ideality are, therefore, seemingly inevitable. However, once christened on completion of its pre-commissioning trials, the impact of any departure from anticipated stage performance becomes the parental responsibility of the maintenance engineer and his finite budget.

TEETHING PROBLEMS

Whilst the stage's core integrity on commissioning is chiefly determined by the calibre of the design team, satisfactory quality control at every phase of construction and installation is implicit to ensuring trouble-free early operation.

The majority of early incidents are weld related, either non-compliance with approved procedures and practices or incorrect selection of consumables. Empirically, it has been found that the time to failure is closely related to the magnitude of the defect with the propensity for failure reducing markedly within the first few thousand hours (Figure 1)[2]. Associated failures in later life generally result from the defect serving as a preferential site for a secondary damage mechanism to develop, for example creep. Where a collection of defective welds have entered service, the failure threat can be successfully tackled through remaking the joints, a prohibitively expensive and time consuming exercise that renders investment in quality control and inspection prior to entering service a more cost effective approach.

The thin-walled tubing specified for the reheater stage, particularly the stainless steel sections, renders it more susceptible to the detrimental effects of both inherent tube defects not detected during manufacture and arc strikes, typically in close proximity to butt welds and attachments. Either defect type is capable of causing pinhole or crack-like failures in early or later life, adopting the same time distribution as defective welds. However, such defects have been responsible for only a few, isolated incidents and rarely warrant maintenance activity once the stage has entered service.

Not all pre-commissioning faults manifest themselves within the first few years of operation. At the low pressures employed, even sub-specification material can achieve respectable longevity in the less demanding applications. Verifying the compositional specification of tubing involved in early failure incidents is therefore essential, particularly where creep damage is implicated. This will establish whether the incident heralds the onset of an emerging problem incurring significant expenditure or an isolated incident that at most requires precautionary material checks.

MATURITY; CONDITION MONITORING

On entering mid-design life (>40,000 hours), the stage invariably begins to show signs of ageing that will precipitate failures unless addressed through a structured condition-monitoring programme. The damage mechanisms that emerge during this 'mid-life crisis' are born of the thermal, mechanical and chemical environments to which the stage has been subject. The nature and manifestation of these integrity threats are now considered together with the in-situ inspection techniques developed to mitigate the associated failure risk.

External Wastage

General

Pendant tube longevity is almost invariably dictated by external wastage and frequently represents the earliest threat to stage integrity. It is also the easiest tube degradation mechanism to detect visually, rendering it highly amenable to routine monitoring and complimentary preventative maintenance. An experienced site engineer should therefore perform a comprehensive visual and tactile survey of the pendant stages during statutory overhauls to;

- highlight emerging wastage patterns,
- ensure correct positioning of established NDT inspection bands, and
- identify localised wastage remote from expected area of metal loss.

Whilst fireside corrosion has been the dominant wastage mechanism on UK coal fired boilers, instances where tube wall thinning has been exacerbated by, or arisen exclusively from, sootblower erosion are not uncommon, particularly when firing more benign coals. Reductions in wall thickness have also arisen from metal-to-metal contact, whether between tubes or tubes and adjacent support structures.

High Temperature Fireside Corrosion

Excessive fireside corrosion in pendant stages is generally confined to tubes operating at temperatures above 1040F (560°C) and is associated with the development of ash-derived molten alkali metal sulphatic phases on the leading surface of the tube. The primary factors which dictate the rate of metal loss, either in isolation or synergistically, have been identified as tube material, metal temperature, incident heat flux and fuel chemistry[3].

On 'leading' tubes, the damage is generally characterised by wastage flats on the tube surface at approximately the 2 and 10 o'clock positions in relation to the gas flow, sometimes with a bias to either the nearest side-wall or the boiler centre-line. The surface of the wasted substrate exhibits either a pitted, 'orange peel' appearance and/or fine, predominantly transverse, multiple craze cracking (alligator hide), both in sharp contrast to the smooth, invariably ash-free wastage flats associated with erosion damage. Metal loss is generally less pronounced deeper into the bank where the wastage flats tend to occur more towards the 3 and 9 o'clock positions and may even be absent from one side of the tube in some boilers.

Fireside corrosion is routinely monitored through targeted tube wall thickness surveys at major overhauls. Traditionally performed using ultrasonic probes, Power Technology has more recently employed EMAT technology on ferritic tubing. This technique dispenses with the requirement to remove external scale and deposits, thereby affording significant savings in time and money but without compromising measurement accuracy. Ultrasonic techniques remain the only available option for stainless steel tubing or where contributory erosion has removed the surface oxides that serve as the couplant for the EMAT probes. Where fireside corrosion pitting is pronounced, it may be appropriate to grind the tube wall to almost bottom the worst pits towards obtaining reliable measurement of minimum wall thickness. If this activity is confined to the few worst affected tubes, pessimistic corrections can be applied to remainder of stage. Used in conjunction with minimum thickness cut-out thresholds derived from previously determined tube metal operating temperatures, the acquired data is then employed to identify tube insert work to secure the boiler to the next overhaul.

In general, corrosion rates of up to 8mils/year (25nm/h) can be tolerated without compromising the expected design life of tubing. Significantly, however, experience has found that wastage rates rarely remain constant over the stage life for which some allowances must be made. The active nature of the corrosive environment is seldom fully realised during the initial 10-15,000 hours of operation, whilst changes to fuel deliveries and/or modifications to combustion parameters can greatly exacerbate metal losses. The ongoing routine monitoring of stage condition through visual/tactile inspections complemented by strategic NDT must, therefore, represent an integral part of any overhaul schedule.

Sootblower Erosion

Whilst the damage associated with sootblower operation generally commences from commissioning, rates may be influenced by malfunctions in the sootblower assembly or where element/tube displacement pushes an isolated steam flow closer to the sootblower path. However, even established wastage rates can be affected by changes in fouling characteristics associated with the supplied fuel, particularly when established cleaning frequencies are maintained on a cleaner running boiler. This warrants an ongoing review of the sootblower regime to ensure that it is appropriate for the build-up of ash deposits being experienced,

Where a propensity for damage is recognised, the issue of sootblower erosion can usually be successfully addressed through the fitment of protective, sacrificial shields. However, avoiding gaps between shields, certainly coincident with closest pass of sootblower, is imperative as is accommodating sagging of the sootlance at its full extent. As with fireside corrosion, vulnerable tubing should be routinely monitored, positions sought where the development of local vortices might exacerbate metal losses and shield condition checked with displaced and/or degraded shields being reinstated. The requirement for insert work can be determined using the same criteria as employed for corrosion damage.

Metal Rubbing

Considered design has generally mitigated the opportunities for the highly localised wear deriving from metal-metal contact, whether tube-to-tube or tube-to-support structure. However, certain configurations, almost invariably associated with retaining stage alignment, have proved problematic. Once recognised through routine visual/tactile inspection at overhaul or tube leaks, these positions are readily amenable to detection and correction without impacting further on stage integrity.

Certain pendant designs, particularly favoured in US boilier, employ fluid-cooled spacer tubes that run horizontally between the two leading tubes across the front of the stage. Initially secured by a solid attachment in each element, these fixing degrade with service, releasing the tube to ‘rattle’ between the two neighbouring tubes to introduce significant, but localised, metal loss on all three tubes. The immediate failure threat can be addressed through fitment of ‘wear-pads’ at the contact points. Longer-term solutions have involved the adoption of an improved attachment design to maintain the spacer position without compromising tube integrity[4].

Some stage designs have sought to resolve tube misalignment by wrapping mid-element tubes around the inlet and/or outlet legs of each assembly within the stage or through the use of horizontal alignment straps. However, over several decades, some designs have been found to cause chaffing on the adjacent vertical

tubes, often with preferential damage to one steam path within the stage. Subject to the extent of the damage, this has been successfully tackled through selective insert work, local weld build-up or the fitment of wear-pads.

Fatigue

Fatigue related tube failures are generally associated with transient, thermally induced loading at positions of restraint. Whilst boilers subject to high cyclic operating regimes are considered most vulnerable, poor design can dramatically advance the arrival of such incidents. The most vulnerable positions within pendant stages are solid tube-tube attachments and the header stub weld, an overly rigid antler design greatly exacerbating the loading at this position during cyclic operation. However, at both locations it is important to distinguish fatigue damage from premature creep degradation to ensure that the appropriate corrective action is implemented. At attachments, the system stresses develop transverse cracking whereas creep damage driven by hoop stresses is longitudinal in orientation. At the header-stub weld, cracking at the stub-side toe is fatigue related whilst indications on the header-side toe may herald incipient creep degradation of the header shell.

Proactive inspection prior to the first incident is rarely cost effective, particularly in the gas-pass where tenacious ash deposits must first be removed and the mid-bank attachments are often relatively inaccessible. However, once identified, the failure risk can be effectively curbed through targeted MPI/DPI at statutory surveys, subject to distinguishing between original weld undercut and operational damage, with repairs constituting grinding-out the defect and effecting a weld repair if appropriate. Selective inspection frequently presents itself as an option; sometimes the damage may be confined to a specific attachment group, for example close to another fixed point such as the crown seal weld, or biased to stubs at the outboard end of the headers as a consequence of thermal expansion. At all such locations, selective mid-life insert work, often involving revised tube configurations, can be implemented to temper the drivers for fatigue damage.

Creep

Although penthouse tubing is subject to high-temperature oxidation, the associated wastage rates are modest compared with those deriving from fireside corrosion in the pendant section. Consequently tube longevity external to the gas pass is governed almost exclusively by long-term creep degradation, a synergistic function of operating temperature and hoop stress, the latter being related to operating pressure and tube dimensions.

The microstructural nature of creep damage essentially prevents any direct determination of residual creep life[5]. Consequently, condition monitoring has traditionally required the taking of tube samples from selected positions. Extended operation at elevated temperatures causes progressive, thermally enhanced degradation of the tube microstructure. For ferritic steels, this process has been mathematically characterised, enabling a mean metal operating temperature ton be calculated from the degree of microstructural degradation after a known service life. Together with details of the tube dimensions and operating pressure, this derived temperature can be substituted into well established creep rupture equations to determine the residual useful life of similar components still in service. The development of steamside oxides on ferritic boiler tubes also obeys material specific time-temperature relationships, enabling the concomitant metallographic measurement of bore oxide thickness to provide a complementary method of temperature estimation.

Ultrasonic techniques developed and refined in the last decade of the twentieth century now enable the confident non-destructive measurement of bore oxide thickness. Negating the immediate need for sample taking, the procedure allows for the rapid acquisition of data to realise more comprehensively the thermal profile of the stage than accommodated by traditional means. Whilst, subject to good procedural practice, confidence exists in the measured thickness, data interpretation remains subjective with the potential to ultimately compromise the accurate determination of residual life.

Under ideal conditions, the steamside corrosion scale will develop as a duplex oxide, comprising an inward growing spinel (Fe/CrO) and an outward growing magnetite scale (Fe_3O_4), the interface between the two approximating to the original metal surface. Empirically derived kinetics have been successfully employed to translate duplex scale thickness into mean metal operating temperatures towards determining residual creep life. However, excessive metal temperatures (typically >1150F (>620°C)) encourage wustite growth (FeO) in the spinel and/or magnetite, whilst repeated in-service delamination and subsequent reforming of the bore scale within the spinel layer leads to the development of laminated scales. The 'paralinear' kinetics associated with both processes encourage the development of thicker scales at a given mean temperature than their duplex cousins (Figure 2), with this difference increasing with the degree of delamination. This affords the potential for gross overestimate of metal temperature from the oxide thickness measurement if applying duplex kinetics. Furthermore, the inherently random nature of the detachment process renders kinetic interpretation of laminated scales less absolute than for duplex scales. Hence, such scales may afford the ultrasonically measured thickness profile across the boiler width a more serrated appearance than would be anticipated solely from measurement error, particularly coincident with the hottest running elements (Figure 3). The practical implications of these effects are;

- For laminated scales,
  - Duplex kinetics will overestimate the metal operating temperature and the prediction of premature creep failures.
  - Subject to the degree of scale lamination, paralinear kinetics will afford an approximation to actual mean metal operating temperatures
- For duplex scales.
  - Duplex kinetics will afford a good appreciation of mean metal operating temperature and therefore residual life.
  - Paralinear kinetics will significantly underestimate the tube metal operating temperature causing an overestimate of residual tube life from which 'unexpected', premature failures will arise.

Best practice has therefore been to monitor residual creep life through ultrasonic measurement of selected steam paths and to complement this activity with the taking of precautionary tube samples from selected high-risk tube flows. This validates the measurements and determines the nature of the internal oxide, thereby allowing a more precise determination of operating temperature and, hence, creep-life. Significantly, when determining the residual creep-life of penthouse tubing, the reduction in wall thickness at bend extrados positions deriving from the manipulation process should not be ignored, these positions frequently being the position of early failure incidents. The derived temperature estimates can subsequently provide the foundation for determining cut-out thresholds within the gas pass, after making appropriate corrections to accommodate the heat flux, and in header life assessments.

DMW Creep

During the 1960s and into the 1970s, the boiler design teams frequently employed stainless steel tubing where a potential threat from high temperature fireside corrosion was identified. The material transition to the low allow ferritic sections of the stage were made using flash butt welds (electrical resistance technique) or fusion butt welds, available welding consumables dictating the use of 300 series filler metal. The higher solubility of carbon in the austenitic grade steel encouraged carbon diffusion from the low alloy steel during weld manufacture to leave a lower creep strength material adjacent to weld. This inherent weakness was exacerbated by the large difference in thermal expansion coefficient between the two materials causing high loads to be developed at the joint, particularly during cyclic operation. As a consequence, Stations began to experience creep-related failures at the ferritic side toe of the transition welds within 50,000 hours service.

Whilst the failure threat was effectively tempered through routine DPI of the transition welds at risk, a longer-term solution to the problem was required. After a detailed study, Inconel has now become the filler metal of choice for manufacturing material transition joints since the early-1980s. This nickel rich alloy exhibits low carbon solubility and an intermediate thermal expansion coefficient relative to the two parent alloys. In the absence of abnormal loads associated with poor design or poor weld quality, Inconel welds have proved satisfactory for upwards of 100,000 hours service.

TERMINAL DECLINE

As the stage passes through middle age, the propensity for tube leaks increases markedly. Guided by the condition monitoring exercises described above, the failure threat can be policed through selective insert work at surveys and opportune shutdowns. Whilst initially effective, in the short-to-medium term this approach mitigates rather than eliminates failure threat. Ultimately the failure incidents and the expenditure involved in managing the risk will warrant stage replacement, either wholesale or as a sequential programme extending over a decade or more depending upon the nature of the active mechanism in the different sections of the tube bank.

However, instances may arise when failure prevention is not an option or is ineffective, a situation when tube leaks must be expected. In these circumstances a need exists to predict the time at which the failure rate becomes unacceptable, not simply the time to the first failure, which may itself be difficult to anticipate. At its least sophisticated this constitutes an assumption that failures will simply continue at their current rate. However, the forward projection of tube failures has been achieved with a good measure of success by employing the Weibull Distribution Function (Figure 4), a versatile statistical tool for the analysis of reliability life data and hazard probabilities [2,5]. The forward projection of failures achieved with this technique has encouraged optimum stage replacement by balancing the financial penalties of incurred tube leaks against the returns on deferring the stage maintenance work.

REPLACEMENT; A STAGE REBORN

When the economic arguments for stage replacement have been presented and accepted, the next key decision is whether to purchase a like-for-like design or to take advantage of the advances in both tubing materials and fundamental design concepts since the original stage was conceived many decades previous. Whilst the thermal performance of the established design is tried and tested, inevitably the damage mechanisms warranting its refurbishment will return, potentially much earlier if transitions to more onerous operating regimes and or moves to firing more challenging fuel types have been, or are being, encountered.

A critical review of the stage design offers scope to upgrade materials, temper the active failure mechanisms, reduce future maintenance requirements and significantly extending stage longevity. However, exploiting the available data acquired from the various condition monitoring exercises, particularly with respect to temperature profiles and wastage rates, is central to determining the suitability of any new construction. How these issues pertain to the potential for stage improvement are now considered.

Material Selection

Since the early 1990s, advances in alloy development have presented the design engineer with a broad selection of tubing materials to complement the established group available to the original design team. However, only a relative few have found favour;

T91 – Deriving from the 9%Cr1%Mo steels developed in the 1930s for the oil industry, T91 was the product of 1980s collaborative work in the USA, offering a ferritic steel with improved high temperature mechanical properties for nuclear steam generators. By the early-1990s, its good thermal, mechanical and corrosion performance made T91 the material of choice for both penthouse tubing and headers in superheater and reheater stages operating at temperatures up to 1110F (600°C), and sometimes up to

1200F (650°C). However, concerns have been raised regarding its high temperature (>1110F (>600°C)) oxidation resistance whilst its mechanical performance is highly sensitive to compliance with approved procedures for welding and manipulation.

HCM2S (T23)– A relatively recent development of the established T22 grade that achieves high temperature performance, comparable to T91, through the addition of tungsten (at the partial expense of molybdenum), niobium, vanadium and boron. Priced similarly to T91, but with no requirement for post weld heat treatment courtesy of low carbon levels, this alloy is now under consideration for penthouse applications.

HR3C – An alloy that exploits the excellent high temperature corrosion performance of T310 (25%Cr20%Mo) whilst showing markedly superior creep properties, courtesy of controlled heat treatment and the addition of niobium and nitrogen. The material has been successfully deployed over the past 6-years on UK plant in pendant applications demanding high corrosion resistance, locations where higher cost coextruded tubing had been favoured since the 1970s. However, as with T91, its mechanical performance has been found to be highly sensitive to compliance with approved procedures for welding and manipulation.

Pendant Steam Flow Distribution and Thermal Performance

The original configuration and size of the pendant section would have been optimised towards guaranteeing a thermal performance for a given reference fuel. However, as discussed earlier, the characteristics of current and future fuel supplies may differ markedly from these 'reference' coals with the result that the heating surface may be under or over performing. Consequently, the potential exists for tube metal operating temperatures greatly above design with implications for fireside corrosion and creep.

In the decades since boiler commissioning, the software for modelling both boiler thermal performance and steam flows has advanced greatly, enabling the optimal heating surface arrangement for different fuel supplies and/or combustion configurations to be identified with confidence. Designs to temper extreme temperature imbalances across the boiler width can be readily considered, including the introduction of flow restrictors, changing heating surface tube paths (eg use of wrapper tubes for tube alignment and steam flow distribution) or changing the tube wall thickness. The overall impact of adopting a simpler tube arrangement towards reducing fabrication costs and/or simplifying the power stations spares holdings can also be evaluated.

If the modelling exercises show that the heating surface arrangement can be optimised then the designer is faced with the challenge of establishing whether it can practically be accommodated within the available space, always mindful of the supporting requirements. The associated economic benefits of optimising performance, such as achieving target steam temperatures, minimising/eliminating reheater attemperator spray and reducing the reheater pressure drop must be appraised against any additional cost due to changing the tubing arrangement. It is also imperative that precautionary checks are made to ensure that the revised arrangement will not have a negative effect on downstream components, particularly high temperature headers.

Structural Considerations

Attachments are essential to maintaining pendant integrity, preserving tube alignment ("slip-spacers") and support ("solid-ties"). Whilst the importance of the support function is immediate, maintaining tube alignment is equally critical. Steam flow will have been deliberately biased more to the leading tubes of the pendant stage to moderate the intensity of fireside corrosion on these exposed steam paths. Mid-element tubing does not enjoy the same protection and, should attachment degradation cause their misalignment, serious wastage may result. However, long-term attachment degradation in pendant stages is almost inevitable, the very high flue gas temperatures causing chemical attack of the uncooled metal whilst cyclic operation will encourage the thermal fatigue of solid attachments. Even so, careful attention to material selection and design can extend the attachment life.

The need for traditional attachments has been much reduced when opportunities arise, with tangible economic returns. Except where firing high fouling coals might encourage excessive ash accumulation at local discontinuities, element alignment can be maintained by taking an individual tube path and wrapping it around the adjacent tubing ("wrap-arounds"), functioning in a manner similar to a paper clip. Although an established approach, its deployment has been tainted by bad experiences in the early designs, which encouraged localised wear through tube-to-tube rubbing. Engineering refinement has now removed this threat, returning an enhanced life over "slip-spacers" by virtue of being cooled, modest temperatures being preserved by the appropriate biasing of steam flow.

Header Antler Flexibility

Fatigue cracking at the header-stub welds is often associated with poor antler flexibility, a problem that can be exacerbated by significant temperature differentials between adjacent tubing during start-up and significant header longitudinal expansion. Logged thermal data acquired from local to the header during a typical start-up therefore provides the foundation for understanding the nature and magnitude of the problem to be corrected.

Towards improving antler flexibility, any new tube arrangement must be accommodated within the available space and complement the existing header stub arrangement, unless this too is to be replaced. Significantly, if existing antlers already support the header, it may be necessary to incorporate individual header supports on account of the improved antler flexibility.

The designer is afforded greater freedom where the header will also to be replaced, not only removing some restrictions on the antler arrangement, but also provides an opportunity to improve the header arrangement, for example using multiple headers reduce the relative longitudinal expansion. However, the practicalities of such a modification depend upon the existing steam path from the original header and the available space to accommodate the new arrangement. The necessary supporting arrangements for the replacement headers and the position of any associated safety valves must also be accommodated.

THE NEXT GENERATION

Wholesale stage replacement is rare, the refurbishment more often comprising a sequential programme extending over a decade or more as specific damage mechanisms progressively compromise the integrity of pendant tubes, antlers etc. as described earlier. The potential for problems deriving from sequential refurbishment cannot be ignored and must be accommodated both during the stage re-design and quality auditing during the installation. These include;

- **Safe-Ends** - Where stainless steel tubing has been specified to tackle corrosion and/or creep issues, it has become standard practice to incorporate "safe-ends" at terminal points to allow like-to-like site welds between the replacement and existing components. Although the additional row of welds can add significantly to the supply cost, the improved DMW quality relative to site-made welds enhances joint longevity.

- **Missing Links** – The replacement of different sections of a stage may be separated by several surveys. At each instalment, it is important to reflect on the position of the earlier cut lines towards avoiding the retention of original tubing between two tube sets of more recent vintage. This has arisen most often at the crown-seal, a position difficult to accommodate in a refurbishment and mid-way between the target of pendant and penthouse tubing. Results can be unexpected, but inevitable, creep failures and a return to the scene of the crime to effect remedial action.

- **Quality Control** – Compliance with approved standards and procedures for tube manipulation, attachment fixing and tube joining should be ensured, extending to the use of specified materials. Incidents have arisen where welders have sought to improve productivity, at the expense of joint longevity, by employing 300 series filler metal for DMWs in preference to Inconel; fortunately this was identified before commencing service.

SUMMARY

The intended longevity of a reheater bank can be greatly compromised by seemingly inevitable changes in operating regime, fuel deliveries and combustion technology relative to those anticipated many decades previous at stage conception. Whilst such departures in performance from the designers' ideality can heighten the propensity for wastage, creep and fatigue, the failure threat can be tempered, but not eliminated through routine, strategic condition monitoring. When ultimately stage replacement is economically expedient, scope exists to improve the stage thermal and structural performance together with endowing greater tolerance to dominant failure mechanisms through improved tube arrangements and employing superior material grades, but not necessarily at an economic premium.

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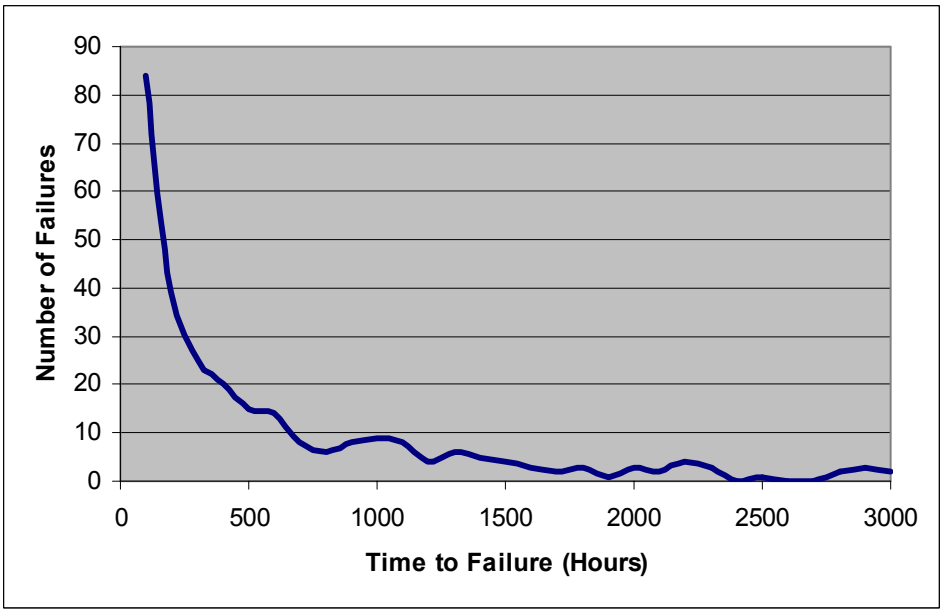

Figure 1; Time Distribution of Defective Weld Failures[2]

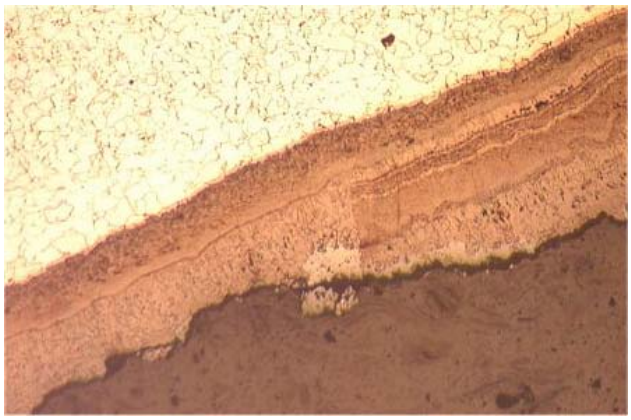

Figure 2; Duplex (left) and Laminated (right) Scales, Note Greater Thickness of Latter

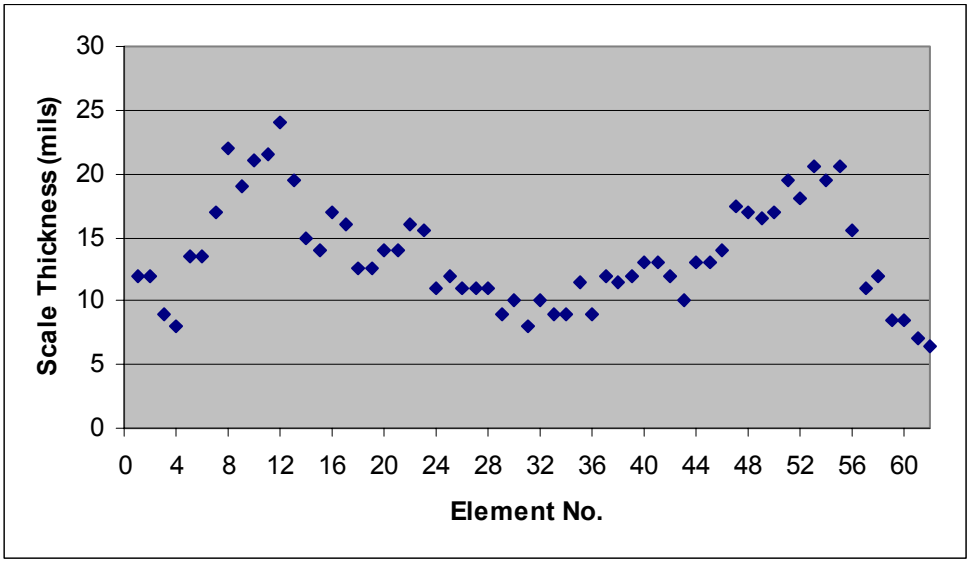

Figure 3; Impact of Laminated Scale Growth on Steamside Oxide Thickness Measurements Across the Boiler Width, Affording Scatter to the Background 'M' Shaped Profile

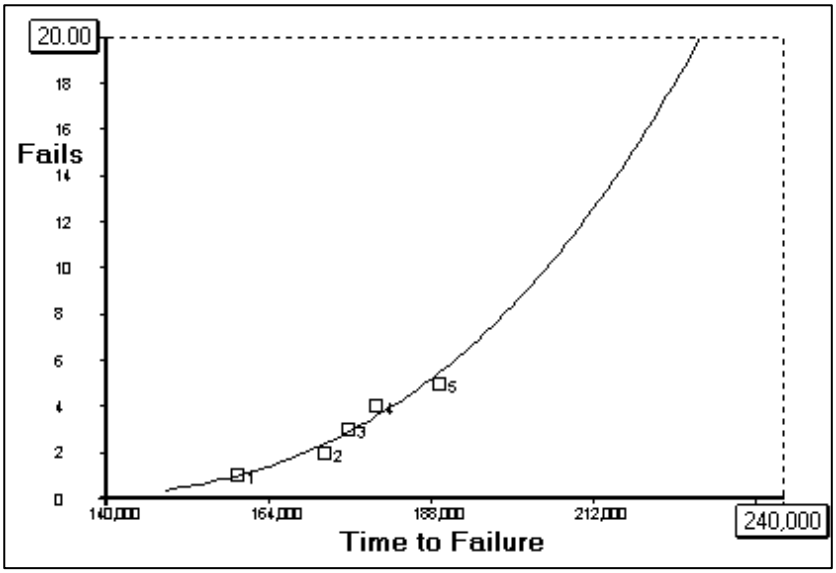

Figure 4; Forward Projection of Failure Sequence (numbered squares) Using Weibull Statistics

Application of Probabilistic Risk Assessment to High Temperature Boiler Tube Remaining Life Analysis

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1.0 ABSTRACT

High temperature boiler tube failures due to long term creep and fireside corrosion continue to be a major problem in utility boilers. Several NDE tools and predictive models have been developed over the years to help minimize this problem. This paper illustrates a methodology developed at Progress Energy which applies probabilistic modeling to tube failure prediction and integrates the result with a financial analysis. An illustration of how tube failures are modeled and its implementation using spreadsheet applications will be discussed.

2.0 INTRODUCTION

The modeling and prediction of high temperature failures requires a multidisciplinary approach and many times involves a compromise due to constraints of time or money. Most utilities use an NDE approach to the problem, since this method is relatively quick and convenient. It allows the acquisition of a large amount of information in a relatively short period of time. However, there are compromises with this approach. The method discussed here takes a more operational approach. The tube model is set up to use primarily operational inputs (heat flux, steam flow, etc.), and the damage in the tube is tracked with time until a failure criteria is met. This model is then implemented within a probabilistic simulation routine to allow the input variable uncertainty to be quantified and to calculate the result in terms of probability of failure.

3.0 FAILURE MECHANISMS

The failure of high temperature superheater and reheater tubes is usually attributed to one of two failure mechanisms. According to EPRI documentation[1], these are fireside corrosion and long term overheating/creep failures. The metallurgical examination of the failed tubes usually indicates that the failure mechanism is creep, but this is because the wall loss associated with fireside corrosion increases the stresses to the point that final failure is by creep. The relative contribution of either mechanism to failure should be taken into account not only when devising a remaining life model, but also in developing an effective corrective action plan.[2]

The basic tube life model discussed here looks at creep rupture or long-term overheating, defined as the stress that causes rupture in a specified time at a given temperature. This is accelerated in boiler tubes by the ID oxide scale growth which increases tube metal temperature over time and by OD wall loss from fireside corrosion which increases the stresses over time. (Figure 1)

4.0 REMAINING LIFE MODEL

If the stress and temperature in a boiler tube were constant, the calculation of remaining life from the material data would be very straightforward using available material data. For high temperature boiler tubes, the remaining life model is based on a mechanistic model that integrates the change in variables which affect the damage accumulation in the tube. At the heart of the model is the tracking of this damage accumulation. This is a nonlinear function in boiler tubes, because the variables of temperature and stress are constantly changing, affecting the life of the tube. Several models have been proposed[2, 4, 5, 6] using life fraction or damage accumulation as a means to accomplish this.

The simplest and most familiar is the Robinson Life Fraction Rule[4]. To implement this, discrete time steps are chosen, and the temperature and stress are calculated at each step. This can be easily done in a spreadsheet using time steps of a few thousand hours. The time to failure (T_f), based on stresses and temperatures and material data are calculated, and a life fraction is computed based on the ratio of the time step and time to failure. This life fraction is summed up over all the time steps until the sum equals one, which is considered the point of failure. The sensitivity of the model to changes in the time step size should be investigated for each case due to the nonlinear nature of some of the governing equations.

A similar model can also be created using strain rate. This model also uses time steps but tracks strain increments and damage instead. When the damage exceeds a predetermined level, failure is assumed (Figure 2). Using this model has the advantage of modeling the strain deformation of the tube and thus calculates any stress increase from change in geometry. Either of these basic deterministic models can then be used within a probabilistic calculation to come up with a probability of failure. We will look at the way the main variables are modeled, how they change over time, and where input data is obtained.

5.0 THERMAL MODEL

One of the principle variables affecting remaining life is temperature. Since any remaining life model will be most sensitive to this input, a great deal of care must go into determining the local temperature conditions for the remaining life calculation. The most popular methodology used today is utilizing NDE measurements of ID oxides and then calculating a mean exposure temperature over time. Several models relating time, temperature, and thickness have been proposed and used by various organizations. The resulting scatter is significant with results varying by more than 100°F for the same scale thickness (Figure 3). Remaining life techniques that rely solely on NDE data are most effective for comparison purposes and can be drastically affected by spalling[4].

Another approach is to model the entire tube section in the boiler. This requires knowing not only the geometry but also the steam properties (flow, temperature, and pressure), gas properties (flow and temperature) and heat flux. The equations relating these and some typical values are available from the B&W Steam book[5]. A step-wise solution was developed in a spreadsheet from these relationships. It used initial conditions for the steam and gas temperatures and solved for final gas and steam temperatures. Several commercial finite element and CFD packages

would allow the user to thermally model the tube bundles as well. This allows the analyst to see the local conditions (total heat flux, gas temperature, and steam temperature) where life expectancy would be lowest.

The model of the temperature through the wall (Figure 4) has been defined in many texts[5, 6]. Basically, there is a resistance to heat transfer at the steam film boundary inside the tube, conduction resistance through the oxide layer, resistance through the tube wall, and film resistance on the gas side. By knowing the heat flux and steam flow, the through wall temperature gradient can be calculated. The wall temperature then becomes the input calculating time to failure or remaining life.

The oxide thickness changes over time and several growth rate equations have been proposed[4]. In general these are parabolic or logarithmic relationships. For this model instead of calculating a temperature from a measured scale thickness, we use the formulation to calculate an incremental growth of scale thickness for a given temperature over a time step. The cumulative scale thickness calculated at the time when the boiler was examined is then compared to actual ID oxide thickness data as a check.

6.0 STRESS MODEL

The modeling of the stresses in a boiler tube can be made very simple, such as using hoop stress, or complex by using finite element methods. A simple model using the equivalent (von Mises) stress calculated from the three principle stresses was found to be the most representative[4] and is what is currently implemented.

The change in stress is primarily the result of wall loss from OD fireside corrosion as shown in Figure 5. For most cases the best approximation available is to use a linear loss rate based on NDE data; however, many corrosion phenomenon are nonlinear and dependant on ash fusion temperature and ash constituents[4].

7.0 MATERIAL DATA

One of the most difficult problems in constructing a model is choosing what material data to use. Typically Larson–Miller Relationship Curves[7] have been used which relate temperature and stress to time to rupture, but the scatter of the data results in failure times of one order of magnitude. Using mean data may result in an optimistic result, while using minimum data may be too pessimistic. In either case this can result in loss revenue from making a decision to replace too soon or too late.

One solution would be to get better data with less scatter. This was accomplished by using data from Project Omega conducted by the MPC which relates temperature and stress to strain rate. Unfortunately, this is not in the public domain. Another way to narrow material uncertainty is to have a creep rupture test run on material samples from the boiler in question. This has the disadvantage of cost and time. Another solution to the problem of the data scatter is to implement a probabilistic approach to account for the uncertainty in the data which is discussed below.

8.0 PROBABILISTIC MODEL

Many commercially available analyses utilize NDE measurement of wall thickness and ID oxide as the inputs to a model to calculate remaining life. Since a large number of data points can be collected this way, the probabilistic result can be derived by ordering the output data (lives) of all the tubes and extracting a failure distribution or probability of failure curve. This is a simple and effective way of integrating variability of the inputs for stress and temperature (wall and scale thickness) but doesn't account for variability of the material data.

To account for the variability of all inputs, we first take the deterministic model developed above, which tracks the main state variables of stress, temperature and their effect on material life, and incorporate it into a probabilistic simulation routine. Since this model was built in a spreadsheet, there exist several third party add-in software packages[8, 9] to implement a probabilistic solution. These utilize a Monte-Carlo simulation routine that is a numerical integrator to solve for a probability of failure distribution. It works by randomly choosing input values from input distributions you determine and calculating a result. This is done for as many simulations as specified (Figure 6).

For the probabilistic model we must select which variables we are going to treat as distributions and determine what shape they are going to take. The focus should be on the variables to which the model is most sensitive. For instance, time to failure is much more sensitive to temperature than stress. Therefore, the quantification of uncertainty for steam temperature is more important than pressure. The shape is also important. The most common distribution shape is the normal distribution; however, we seldom have enough information to accurately calculate a mean and standard deviation. Many variables are highly skewed to one side and do not have the symmetry of the normal distribution. A log-normal distribution can sometimes be made to fit this type of data. In general, experience has shown that a triangular distribution works fine for most variables, since that is about the level of knowledge we have about their shape.

The variables for the tube model are generally grouped into three areas: geometry, steam properties, and material properties. For the geometry, we treat the ID and fireside wall thickness as triangular distributions. The steam properties of temperature, mass flow, and pressure are treated as triangular distributions as is heat flux (Figure 7). The material creep rate constants or Larson-Miller relationship constants have a normal distribution calculated for them to account for the spread in the relationship (Figure 8). Also the ID oxide thermal conductivity and growth rate constants are treated as triangular distributions.

When selecting variables and their distributions for this type of model, it is important to limit yourself to a particular population. A population is defined as tubes with the same initial geometry, material properties, and exposure to reasonably similar environmental conditions (pressure, heat flux, steam temperature, etc.). If there is a material change or a step change is observed for one of the other variables, the population should be split up and two different analyses performed.

If you have, unfortunately, already experienced failures, these can provide a point of reference to further calibrate the model. If the failures do not fall near the calculated probability of failure line, then the analyst should start reviewing his data and assumptions for errors and then adjust them up or down within reason to fit the actual failures. Many times boilers have undergone operational changes that do not show in current temperature readings and can be masked by ID oxide measurements due to spalling. Sometimes the spread of data for the input distributions is too broad or does not define the leading edge failures well enough. In some cases, the wall thickness was measured thicker than actual due to oxide "notching" (alligator hide) on the OD.

9.0 RISK ASSESSMENT

The output from the above model is a cumulative probability vs. time curve. The shape of this curve will depend on the shape and breadth of the input distributions chosen, but in general will exhibit a "knee" at which the rate of failure rapidly increases (Figure 9). This knee is generally where the tube failures exceed a tolerable amount, and the component requires extensive repairs or replacement. This can be quantified by estimating the cumulative number of tube failures by multiplying the total number of tubes in the population by the probability.

In doing a risk assessment, we must look at not only the probability of failure, but also the consequence. For the case of boiler tubes, we are dealing with a reliability problem which can be equated to an economic problem. This becomes a more effective way of communicating the concept to business oriented managers[3]. Since we are fully quantifying the probability of failure, this is defined as a full quantitative risk analysis. The risk (in dollars) is calculated for each year into the future.

We then must determine what a lost megawatt-hour (Mwh) is worth. The treasury department of most utilities will have spent considerable time determining this, so you should consult them for this information. This will depend on many things including the efficiency of each operating unit (dispatch order), O&M costs, and expected energy market values.

However, simply converting the lost Mwh to a cost is not sufficient for long term decision analysis. The criterion most often used in the Net Present Value (NPV). For this we must take into account the time value of money by factoring in things such as inflation, taxes, and general rate of return. Again your company's treasury department can offer you guidance on how this calculation is made in your company. The cost of repairs or replacement can now be weighed against the impact of the lost generation. Several alternatives can now be weighed (partial or complete replacement), and the best time or window of opportunity can be selected. An example of the cash flow calculated this way is shown in Figure 10.

A more advanced decision analysis[3] looks at grouping multiple projects such as this, to determine the optimal timing of a project, and also to rank them against each other on an equivalent basis.

10.0 CONCLUSION

The life of boiler tubes can be quantitatively modeled and the uncertainties quantified. This can be done within a spreadsheet model using commercially available software. Probability of failure can be converted to financial impact and therefore NPV. This in turn provides information in a form that allows management to make better business decisions.

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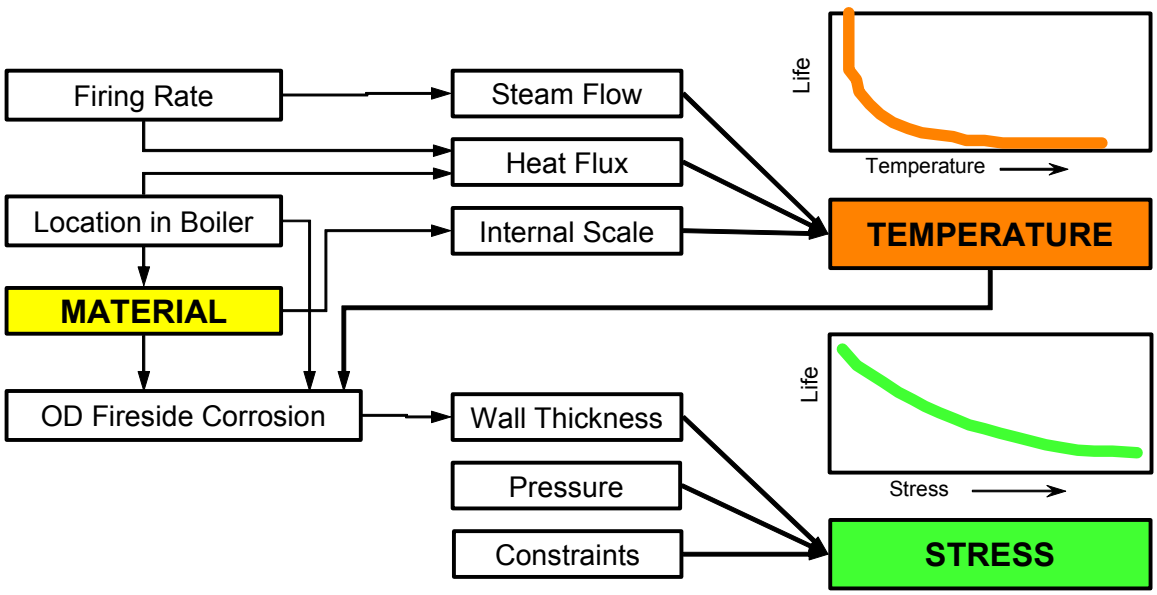

Figure 1, Factors Affecting Remaining Life

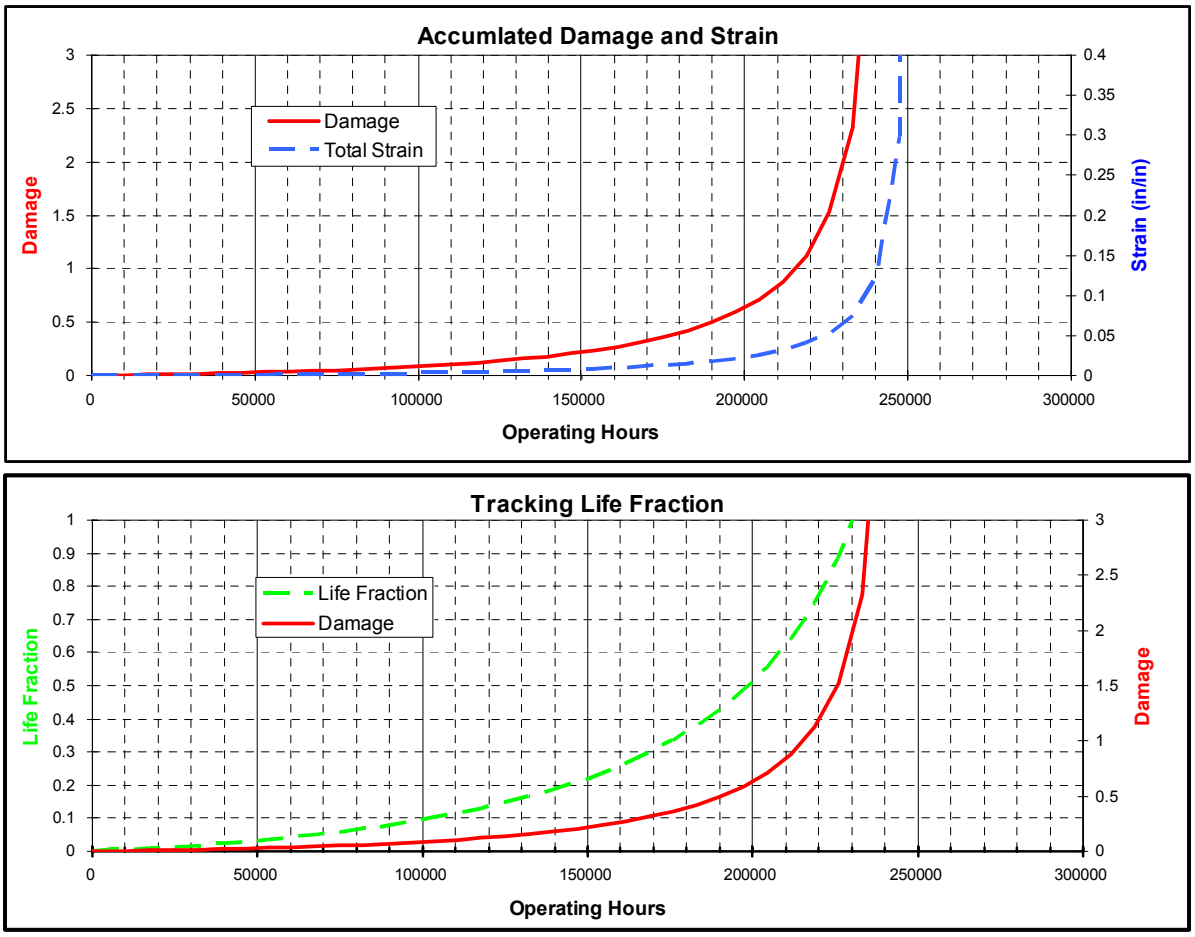

Figure 2, Change in Damage, Life Fraction or Strain Over Time

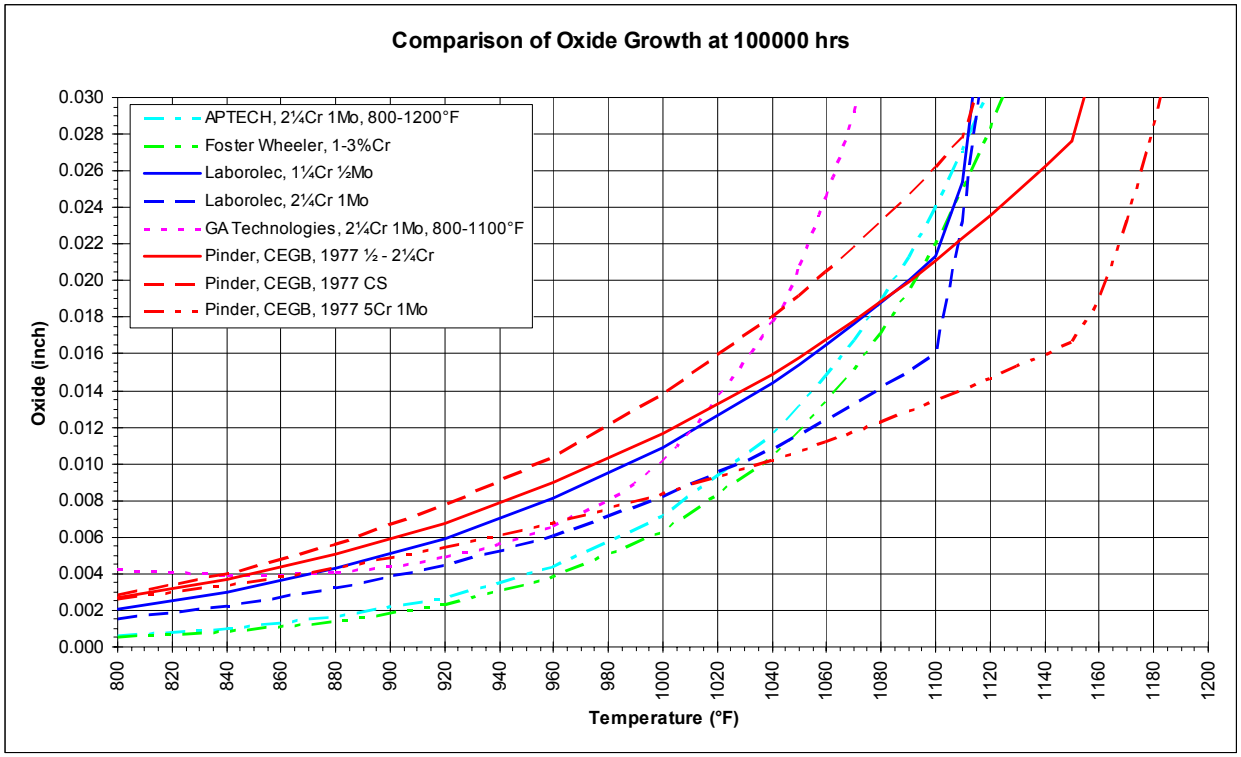

Figure 3, Comparison of Oxide Growth Rate Relationships

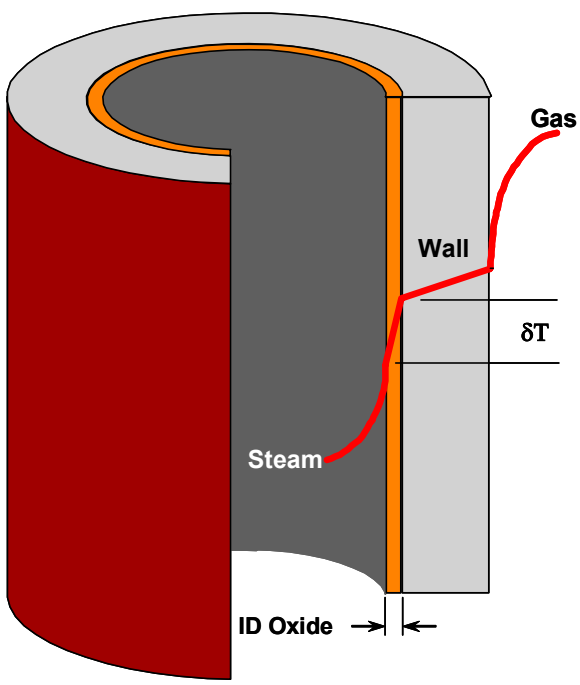

Figure 4, Temperature Profile Through Wall of Typical Boiler Tube

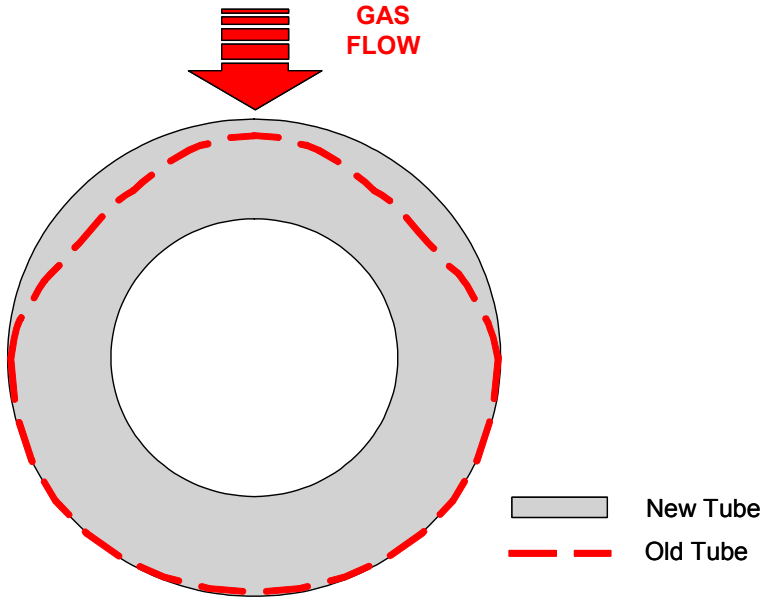

Figure 5, Typical Fireside Corrosion

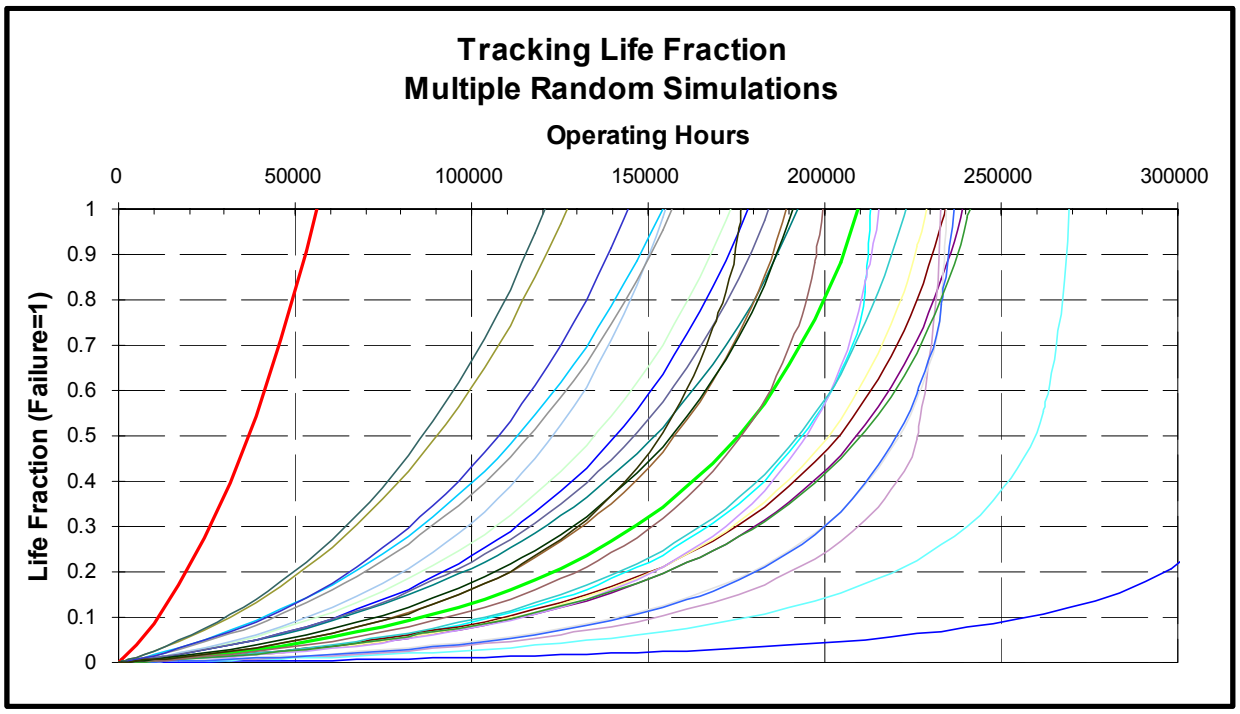

Figure 6, Example Showing Results of Multiple Simulations

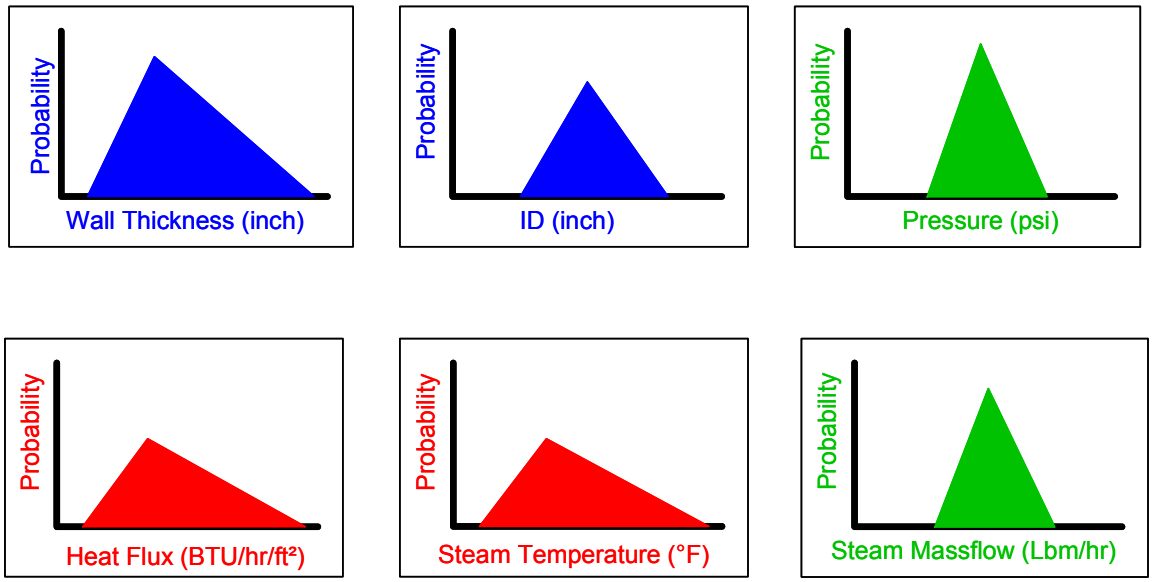

Figure 7, Typical Triangular Input Distributions to Probabilistic Model

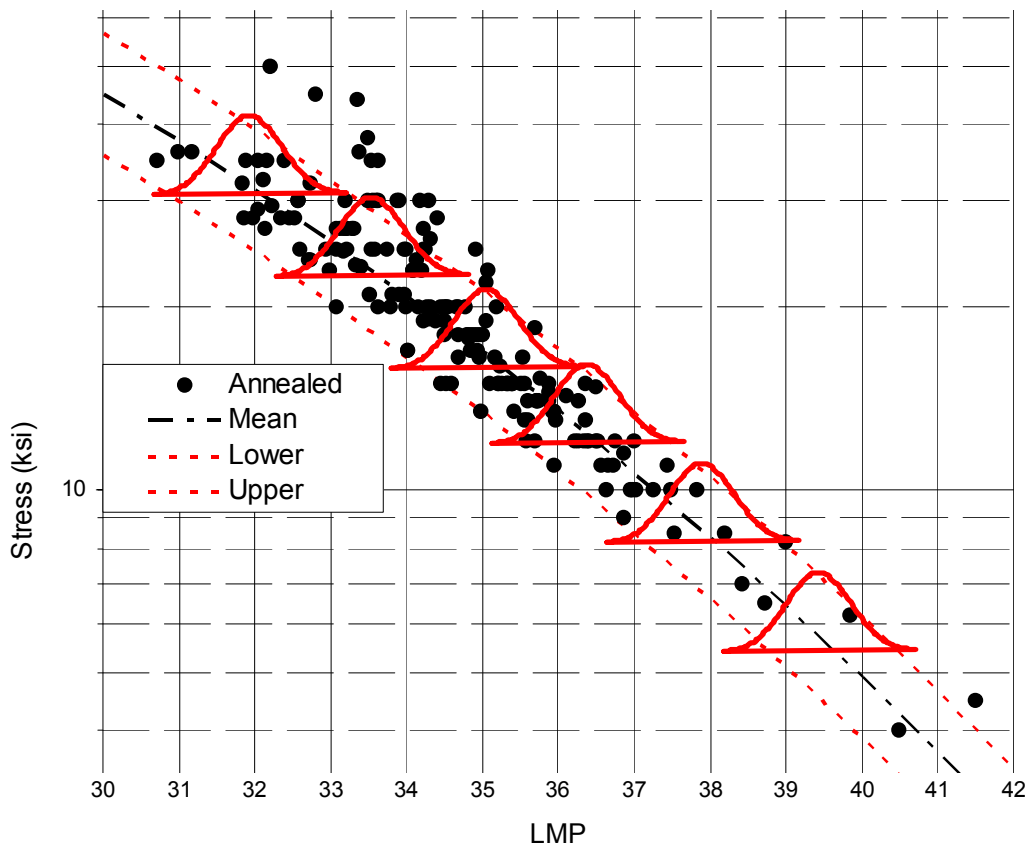

Figure 8, Distribution of Mean Larson-Miller Data

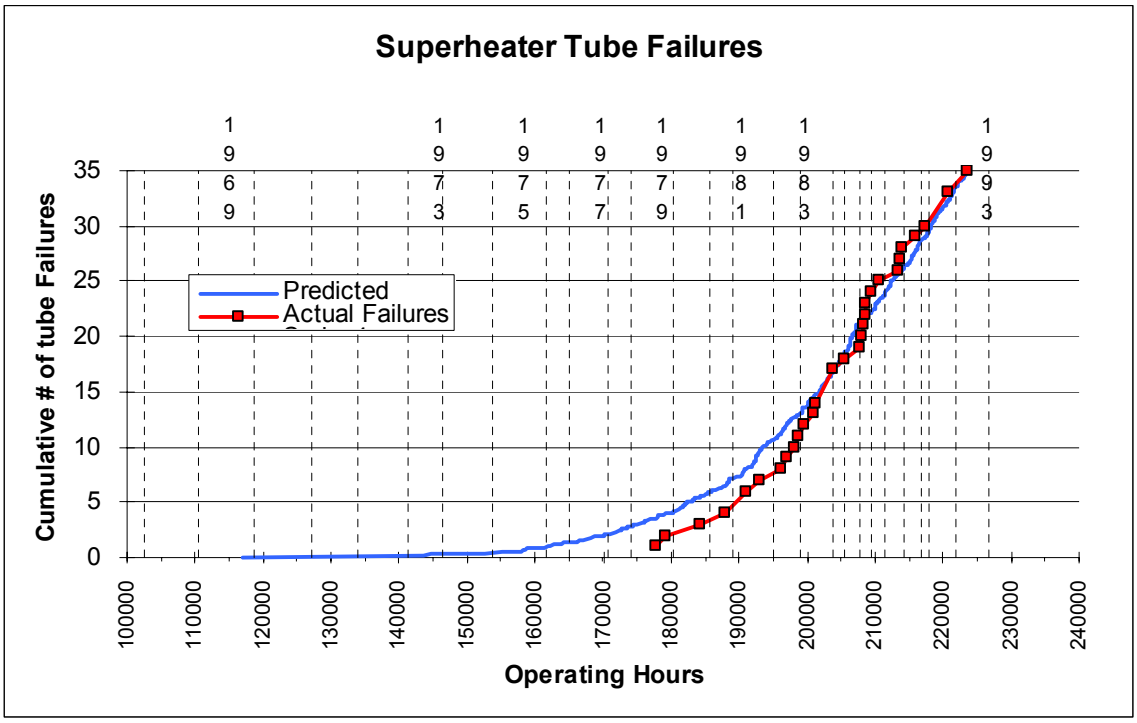

Figure 9, Results of Probabilistic Model Compared to Actual Failure Data

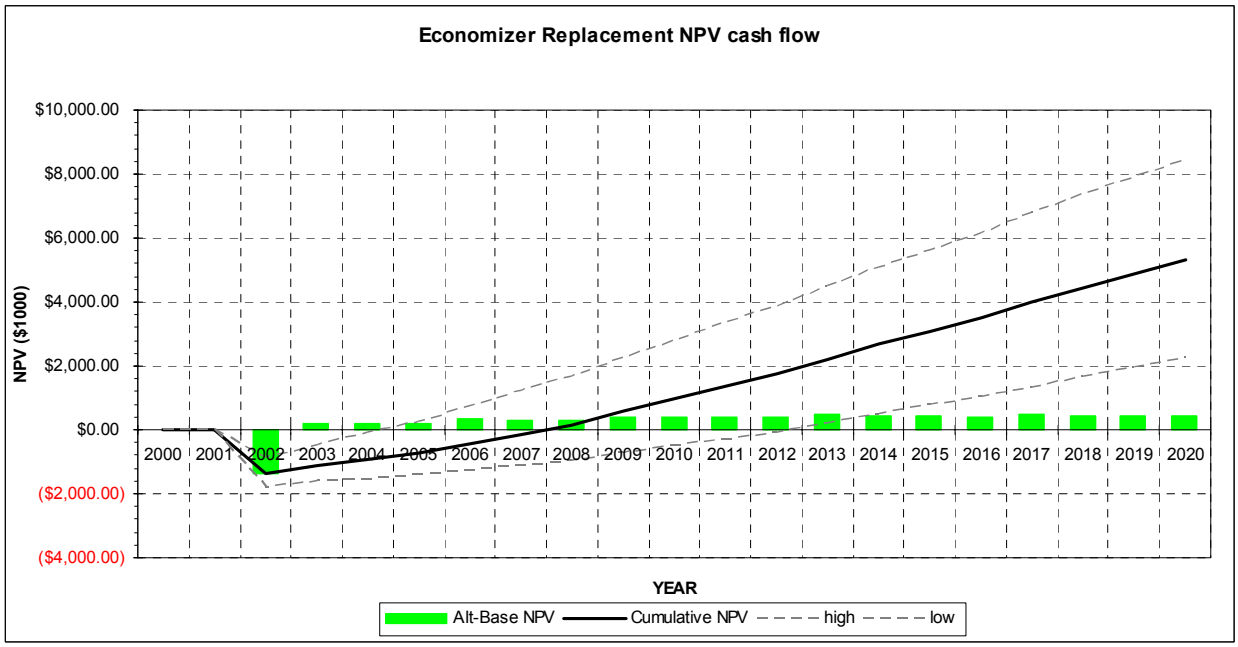

Figure 10, Typical Cash Flow Diagram for Tube Replacement Project

THE USE OF RISK BASED INSPECTION ("RBI") AND WARNING LEVEL APPROACHES FOR DETERMINING INSPECTION BOILER TUBING

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ABSTRACT

There is now much interested in the development of risk based strategies for maintenance planning including assessing appropriate inspection strategies and making economic life estimates of critical components.

This study examines this problem from a very practical point of view by studying a significant body of tube thickness inspection data collected in a power station. This data naturally has all sorts of difficulties. For example there are issues related to the accuracy and correctness of the measurements. Then there is the issue of how to use the data to determine deterioration rates and life expectancy.

This paper examines this data using

- a method developed by the authors: a procedure based on a "warning level" approach and
- a suggested interpretation of the American Petroleum Institute's technique of "risk based inspection".

1 Introduction

1.1 The growth of risk based approaches

Risk based approaches now have a major influence in the conceptual discussion of decision making in engineering. Risk here is always defined as being Frequency times Consequences. In the case of boiler tubing the key consequences are economic so risk is eventually measured as $/year.

The first book looking at the interaction of statistics, economics and maintenance was probably the small textbook of Jardine, 1973[1]. The first giant public report using detailed risk assessment techniques on a series of complicated plants was the Reactor Safety Study of 1975[2]. Since then the whole activity has been ballooning at an apparently exponential rate.

Risk-based inspection guidelines have been created by several technical societies, most notably the ASME[3] and American Petroleum Institute ("API")[4]. Various consultants and insurance companies are now examining aspects of fossil fuel generation using these approaches[5]. The European Union has a Euro 3.6 program termed Risk Based Inspection and Maintenance Procedures ("RIMAP") which aims to "define the technical content [of risk based approaches], links to local legislation and to integrate this approach with the day-to-day operation of the plants"[6].

Monash University is involved in the Co-operative Research Centre for Integrated Engineering Asset Management ("CIEAM") [$A85 million over 7 years]. Program 1 of the CRC aims to "develop … a strategic integrated framework that optimises asset management systems"[7]. Risk based assessment of maintenance major issue in our view of asset management.

1.2 Mechanistic versus risk based approaches

The origins of this paper lie in the question as to what is actually possible to support risk based frameworks when applied to one well know problem: boiler tube failures. As is well recorded boiler tube failures are the major single source of loss of availability of coal fired power stations. The seminal work of Dooley and McNaughton on boiler tube failures is a handbook of technical (or mechanistic) approaches to failure avoidance[8] in these power stations.

A somewhat different approach to the problem can be obtained by risk based approaches (Price[9]). In this approach the failures of boiler tubes is regarded as a basically time dependant failure mechanism. Time dependant failure mechanisms include wear, corrosion, creep and several forms of cracking. The frequency of these failures can be described by a time dependant function such as an appropriate Weibull function.

The defence against the failures is basically an inspection system. This is also a statistically described process since no inspection technique is perfect and no inspection is entirely accurate. In the case of boiler tube inspections there are numerous difficulties to do with capability of the inspection methods and the human difficulties of the inspections.

Introducing economics into the assessment procedure introduces new levels of complexity. Currently few of the published approaches (including the ASME and API methods) assume other than the risk of various failures has to be kept below certain arbitrary levels. The economic balance involved in the decision making process has not yet been factored in. The balance is between the very large cost of forced outages, the smaller but still significant cost of inspections and patch repairs and the cost of complete replacement if the component.

Price[10] assumed the ratio of cost of inspection/cost of forced outage to be 1/10, a ratio not improbable in the area of thickness and other detailed inspections of boiler tubing. The conclusion of this work was that if there is a large population of similar tubing that requires a significant cost to inspect, this will affect maintenance decision.

1.3 The setting for this paper

This paper is an attempt to take this discussion further by examining an excellent set of tube thinning data that was collected at a large power station. The purpose of this work thus is to balance the intensely practical information that is actually collected against the needs for information in a comprehensive risk based approach.

In this paper we develop the theory of to use large quantities of data notionally describing a time dependant deterioration mechanism for the estimation of future maintenance strategies. In addition we have looked at the issues of accuracy of inspections such as ultrasonic thickness measurement.

We also have examined the application of the risk based inspection approaches that have been published. The most relevant and advanced technically is API 581. The intention of API Risk Based Inspection ("RBI") is to be a "useable and understandable tool at a plant inspection level by

simplification of complex models". The API Base Resource Document API 581 identifies RBI as an integrated risk management tool, which provides a methodology for determining the optimum combination of inspection methods and frequencies.

API 581 was developed for the petrochemical industry and thus the question of relevance of the detailed data and the approaches used to steam generation is of interest. A "Boiler Module" is on the schedule of development. However Appendix G "Thinning Technical Module" for process equipment and the draft of API 581 Appendix O "Above ground storage tanks" provide an indication of the direction that might be expected for a tube thinning model[11].

Some consultants are also apparently using thickness data to advise boiler owners[12] but it is unclear how much use is made of statistical analysis in that work.

1.4 API 581-quantitative RBI analysis

API 581 has introduced a systematic and simple approach for likelihood and consequence analysis. For likelihood analysis, API 581 has categorized all the factors, which effects on failure frequencies to determine more accurate failure probabilities:

$$\text{Frequency}_{\text{adjusted}} = \text{Frequency}_{\text{generic}} \times F_E \times F_M \qquad (1)$$

Where

$\text{Frequency}_{\text{generic}}$ is the generic failure frequency from a compilation of available equipment failure frequencies Data is given in books and Table and Fig 8-1 of API 581

F_M is the Management systems evaluation factor. (a measure of the companies management effectiveness(See Fig 8-1, API 581)

F_E is the Equipment modification factor, the product of four sub-factors:

Technical Module sub-factor ("TMSF") is a factor dependant on the modes of deterioration experienced by the equipment and the effectiveness of inspections

Universal sub-factor covers conditions that effect all equipment in the facility (eg seismic activity)

Mechanical sub-factor Characteristics of construction such as complexity and construction code

Process sub-factor Factors influence by process and its stability.

For consequence analysis, API 581 has introduced four major factors: flammable, toxic, environmental damage and business interruption. In this paper we are not examining these matters except to note that the business interruption is by far the dominant effect in most cases in the electric power industry.

In this paper we are examining only the technical module sub-factor, TMSF, since it is the only sub-factor that leads to the development of an inspection plan based on risk. Basically all the other factors considered in RBI are outside the control of the maintenance activity.

2 Calculations

2.1 Linear thinning

The basic failure problem associated with tube thinning is shown in Figure 1. Here we assume that a tube which starts at initial thickness, T_0, is subject to a constant thinning rate $r=\frac{dt}{da}$ where t is tube thickness at time, a.

Because the design of tubes is very conservative (with demonstrated safety margins of up to 5 or more in actual plant situations), the tube will not actually fail until the tube thickness is t_f. This value can be obtained from burst tests. However for prudence and because of the uncertainties (and also because of the influence of Safety Authorities and the Design Code), the plant has decided it will replace tubes when they reach a thickness here termed the warning level tw.

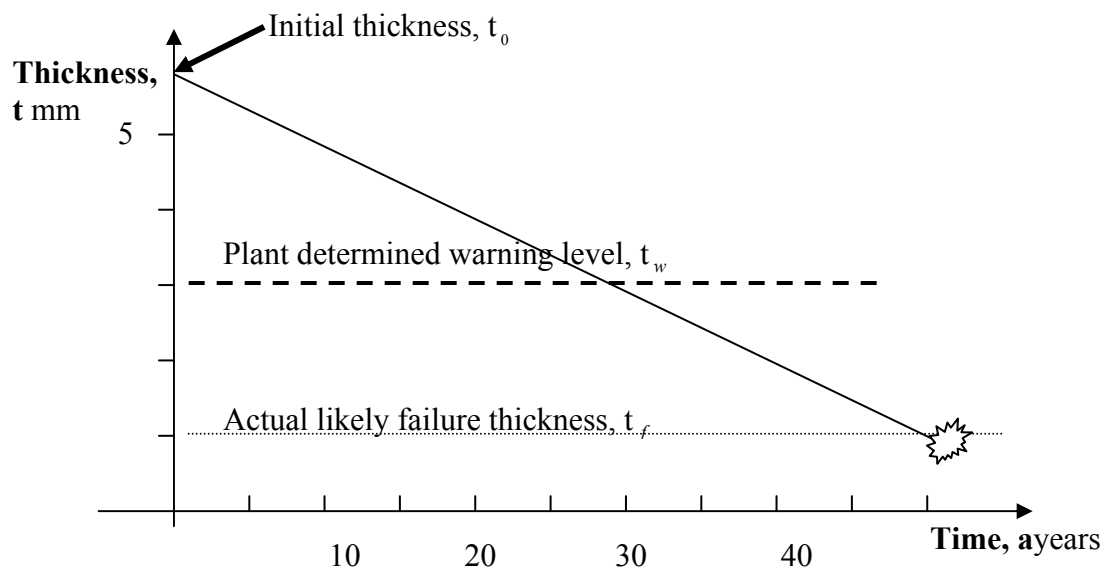

Figure 1
A model of linear thinning for boiler tubes

The equation for linear thinning is

$$t = t_0 - ar \qquad (2)$$

There are several issues in attempting to use this model for making maintenance decisions:

- *Warning level tw*. The method proposed for providing a margin of safety on Figure As can be seen from Figure 1, is to create a warning level tw, at which point the tube would be declared too thin to continue operation. In the example on Figure 1, the choice of a conservative tw results in the tubes being replaces 20 years earlier than necessary. Hence the tubes would have survived 50 years except for the conservatism being applied.

- *How is r, the thinning rate to be estimated?* Thinning rates depend on large numbers of plant and operational dependant factors such as the type of coal being burnt and how often the boiler is cleaned. The best approach would thus seem to be measurement of thickness over a period of years. Even given this there are a number of technical and statistical problems in collecting and extrapolating this data?

2.2 Replacement thickness

There are two approaches considered in this paper:

1. Warning level

In this paper the approach to estimating the warning level, t_w, is to base it reverse extrapolation from the actual failure thickness, t_f. This can be done using the following equation:

$$t_w = t_f + rka_i \qquad (3)$$

Where

t_f	is failure thickness taken to occur when the stress in the tube equals the flow stress (see later), mm
r	is thinning rate, mm/year
a_i	is the interval between inspections, years, and
k	is the number of inspection intervals to be allowed for warning. To allow for the fact that the inspections may have a probability of error it is desirable to have two inspections with a possibility of rejection before the failure point. For this reason k is set to 2, just in case the most severe examples are missed in one inspection.

In the case illustrated in Figure 1, and assuming a four yearly inspection interval, the value of t_w would become 1.8 mm and the tubes would be replaced at 44 years, thus losing 6 years of life or 12%.

However the amount of life lost will also depend on how r is estimated. We will use a conservative 95% confidence interval as discussed below.

2. API 581 approach

API 581 Appendix O draft uses a probabilistic approach based on keeping the failure probability below certain levels for different levels of consequence (Figure 35 and 36). Using the notation of equation 1 above, Appendix O assumes that the likelihood of failure is 1 when

$$ra/t_0 = 1 \text{ i.e. leak occurs when } t = 0 \qquad (4)$$

The objective is thus to keep the ratio ar/t_0 low and credit is given for inspections. For the example of a consequence valued at $1million, Figure 35 and Table 24 suggest that ar/t_0 be kept below 0.35; that is 65% of the life of the component will be lost. With 4 highly effective inspections the ar/t_0 can be raised to 0.82, losing only 18% of life.

In Appendix O, the thinning rate, r, is assumed to be known from prior examples and is not estimated from the inspections.

2.3 Estimation of thinning rate

In the boiler case there may be a known thinning rate, but the more frequent situation is that the thinning rate, r, will have to be estimated from data collection.

The typical situation with thickness data collection is shown in Figure 2. Here there has been some collection of data some years after the boiler was put into service. The data shows quite a lot of scatter and indeed some of it must be wrong because when the data is examined in detail some tubes have been measured to grow in thickness between two inspections.

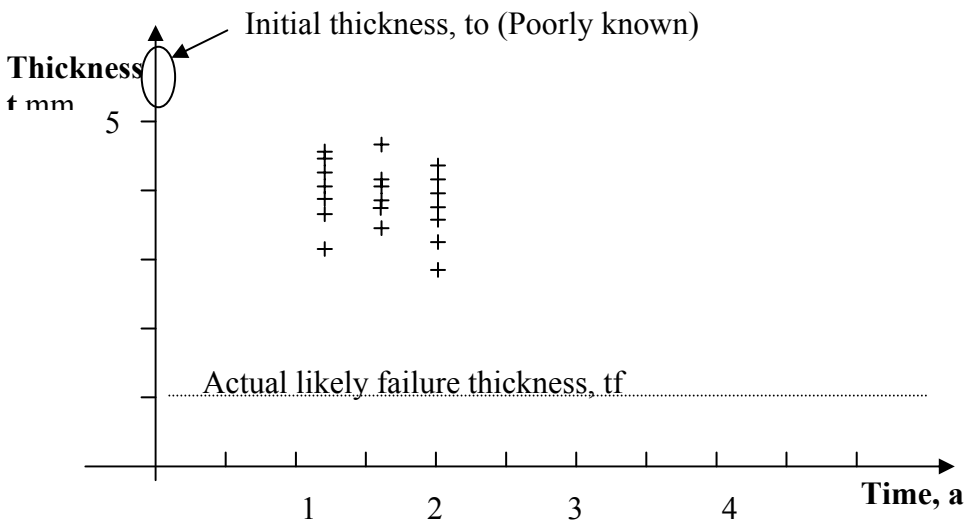

Figure 2
Typical data collected from some mid-life tube thickness surveys.

The means of fitting a curve to this data and how a thinning rate might be estimated from this fitting is the subject of the analysis later in this paper.

2.4 Initial thickness

API 581 Appendix O and much other literature assumes that the initial thickness, t_0, is known. In fact this is far from the case in most situations.

When ordered according to the standards, tubing is delivered with a range of thicknesses falling within a tolerance range typically +- 10%. Fro example this could mean to for a tube of nominally 5 mm thick could vary form 4.5 to 5.5 mm. It is entirely probable that the actual tube thicknesses installed have not been recorded. Plant records are often restricted to ordered thicknesses or, even more misleadingly, minimum design thicknesses which will be at or below the minimum possible delivery thickness. The actual thickness tends, from experience of many inspections, to be at the high end of the permitted tolerance range.

In the particular case of our study samples of original tubes had been held since the plant construction and these had been measured for thickness.

3 Estimating thinning rates

3.1 The data

The authors were provided with inspection data of the power station over a period of 5 years, 1995 to 2000. The data included thickness surveys of economiser, super-heater 2 ("SH2") and super-heater 3 ("SH3") elements, of four boiler units. Super heater 2 and the economiser comprise 148 elements across the boiler and super-heater 3 has 74 elements. The total amount of data was in the order of 40,000 separate data point measurements.

The Power station we are studying has 2000 MW installed capacity. It is one of the largest coal fired power stations in Australia. There are four boiler units which entered commercial operation between 1984 and 1988. The boiler is fuelled with pulverized brown coal taken from the adjacent mine. The coal has a high moisture content 62.50% and low ash content 1.5%. To reduce ash build up on tubing there is a system of steam and water soot blowers.

Areas of inspection on each element are middle part between carriers A to F. The locations of these inspections are indicated on the Figure 3.

The data is important in that it relates to systematic and intensely applied effort to gain what might be thought of as a fairly simple condition measurement of the tubes. In fact this approach was stopped in 2000 and has been replaced and the station now uses stainless steel shield to protect the tubing in this particular area[13].

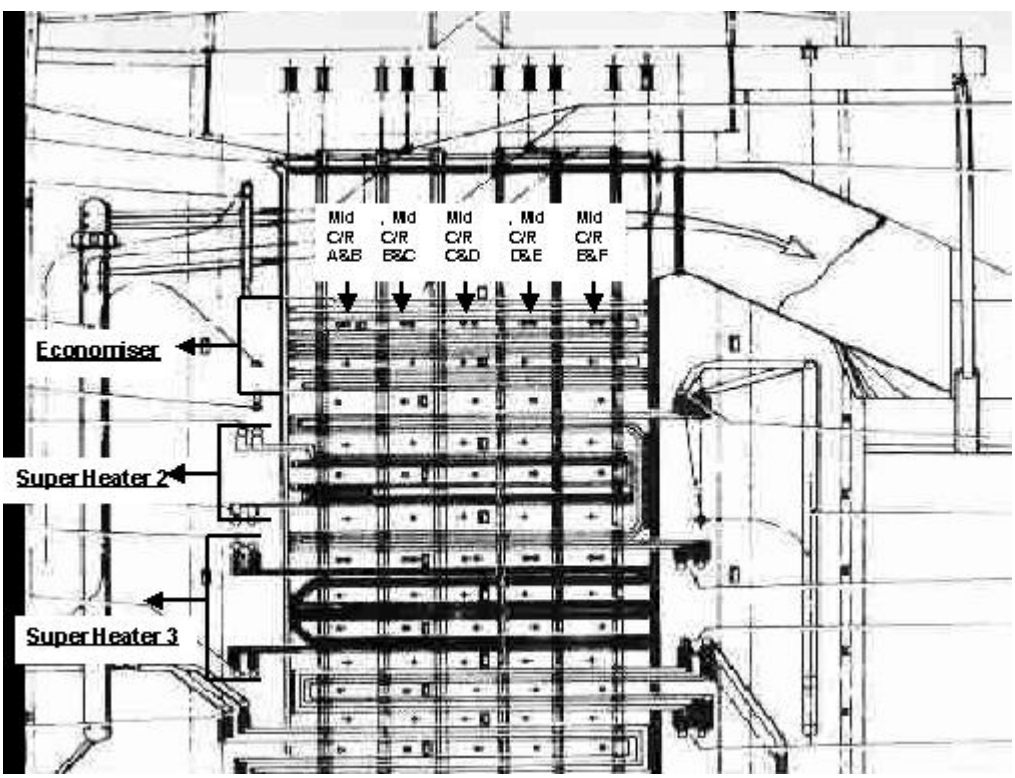

Figure 3
The Economiser, Super heater2 and Super heater3 tubes outline design and notation of the positions which have been measured

3.2 Systematic error and random error in measurement

As part of our study measurements were made in the laboratory using commercially available ultrasonic thickness measurement equipment. These machines give a reading to 1/100th of a millimetre.

The device was first calibrated against test blocks of known thickness and a graph drawn according to the written procedure. These blocks are clean and flat not corroded and curved like normal tubing. We then tested a tube (nominal wall 5 mm) and a pipe (nominal wall 20 mm) in the laboratory where the surface was ground clean on the side to be measured. Subsequently all our specimens were thickness tested using a micrometer.

Using this procedure the data generated was surprisingly bad. There was a systematic overestimate of about 0.5 mm on thickness and quite a scatter, see Table 1. This problem should be factored into the assessment of the tube thickness measurements. In the work presented in this paper it is not directly relevant.

Table 1		
Statistical data for difference between ultrasonic and micrometer, mm		
	Tube	Pipe
Mean	0.540	0.517
Standard Deviation	0.125	0.423
Count	27	69
95% confidence that the error is less than	0.745	1.212

3.3 Data cleaning

Considering the fact that thickness of a tube subject to erosion/corrosion can not increase in thickness over time, some of errors related to human or systematic errors can be found by calculating the difference between the current thickness and the previous thickness.

Figure 4 shows the thinning rates derived from various locations when comparing two measurements in 1998 and 1999. As can be seen there some tubes apparently became thicker. The data thus is cleansed by removing all tubes where the thickness increases with time as shown on Figure 5.

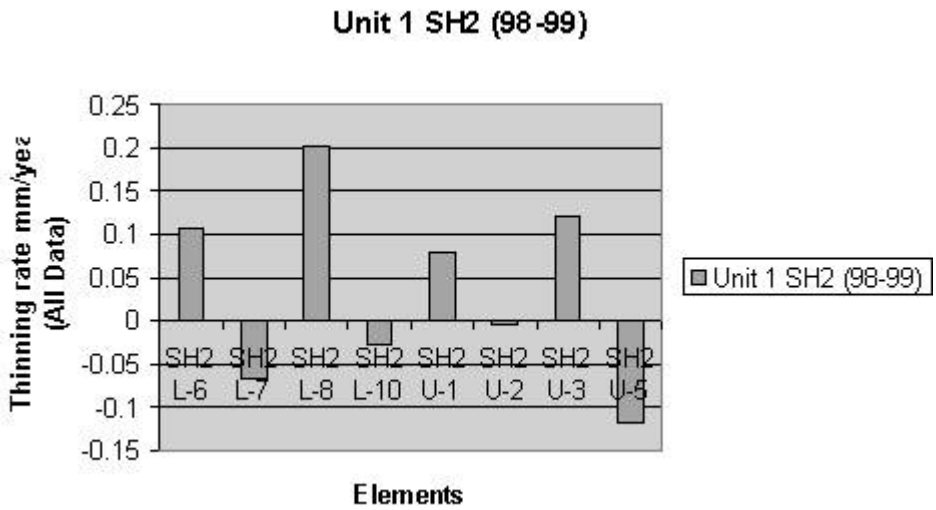

Figure 4
Unit 1 Super Heater- Thinning Rate before Data Removal

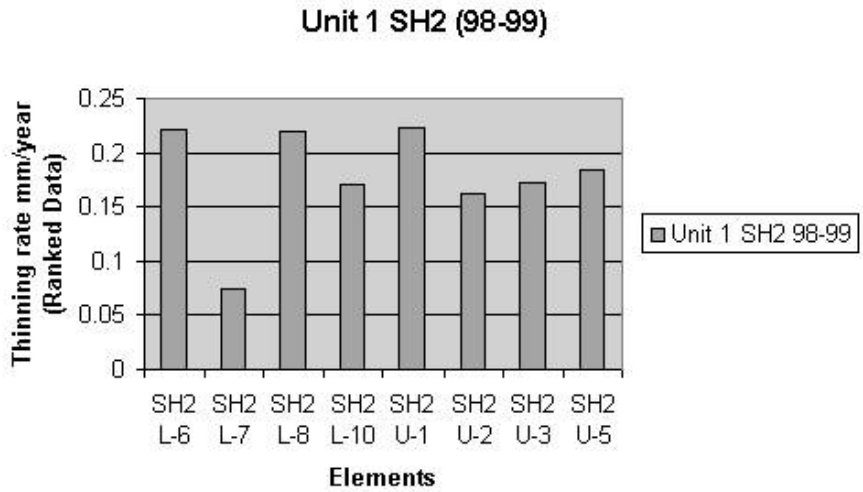

Figure 5
Unit 1 Super Heater- Thinning Rate after Data Removal

3.4 Calculation of thinning rate

After cleansing the data, the straight-line model is hypothesized to relate the mean of thickness (t) to operating years (a). The thinning rate was calculated by determining the best-fit straight line to all the remaining data at each general location. This means, for example, data from all of the economiser upper bank tubes was used.

Regression is used to find out the best relationship between thickness and operating years. The R^2 value (coefficient of determination) gives an estimate of goodness of fit of the function to the data. R^2 is calculated from the sum of the squares of the residuals divided by the sum of the squares of regression. R^2 close to unity indicates a good fit of model to data. Data with R^2 less than 0.6 was rejected. The thinning rates determined are shown on Table 2.

Table 2			
Thinning rate estimates for Economiser and SH3 (See table 4 for SH2)			
Location	**Mean r**	**95% Confidence Interval**	
Unit 4-SH3	0.111	0.125	0.097
Unit 4-SH3Upper	0.110	0.127	0.094
Unit 4-SH3Middle	0.112	0.143	0.082
Unit 4-SH3Lower	0.111	0.135	0.088
Unit 4-Economiser	0.100	0.129	0.072
Unit 4-Economiser Middle	0.095	0.135	0.056
Unit 4-Economiser Lower	0.118	0.159	0.077
Unit 1-Economiser	0.052	0.065	0.040
Unit 1-Economiser Upper	0.057	0.070	0.044
Unit 1 -Economiser Middle	0.047	0.070	0.025

3.5 Calculation of warning level

The warning level thickness, tw, is calculated as follows

$$\text{tw} = \frac{pD}{2s_f} + \text{akr} \quad \text{Equation 5}$$

Where, s_f is flow stress, (average of yield and ultimate stress) see Table 3.
D tube diameter = 51.1 mm for SH2.
P operating pressure = 17.75MPa

Table 3 shows the materials and those material properties which were used in the calculations. Table 4 illustrates the use of warning levels for super heater 2. In this case $pD/2s_f = 1.95$. Table 4 also derives an estimate of the time for the tubes in the super-heater 2 to arrive at the warning level.

Table 3						
Material code, Yield, Tensile and Flow strength at a notional 537°C						
Boiler Tube	**Material Code (British Standard)**	**ASTM**	**Type**	**537°C, Min Yield MPa**	**Tensile Strength MPa**	**Flow Stress**
Economiser	BS3059-ST45	SA672A45	C Steel	92.2	178.3	135.25
SH2	BS3059-ST620	SA-213 T12	1Cr 0.5Mo	129.4	334.7	232.05
SH3	BS3059-ST620	SA-213 T12	1Cr 0.5Mo	129.4	334.7	232.05

Table 4					
Super Heater 2 Warning Level Thickness Unit 1 and Unit 2 and expected time to reach warning level.					
Location	**Thinning rate r, mean**	**r, Upper (95%)**	**t_w (using upper r and a and k = 1.)**	**Assumed initial thickness**	**Year tubes reach warning level**
Unit 1-SH2	0.105	0.124	2.07	6.31	34.2
Unit 1-SH2 Upper	0.104	0.130	2.08	6.31	32.5
Unit 1-SH2Lower	0.106	0.134	2.08	6.31	31.6
Unit 2-SH2	0.140	0.164	2.11	6.31	25.6
Unit 2-SH2Lower	0.128	0.147	2.09	6.31	28.7
Unit 2-SH2Upper	0.153	0.195	2.14	6.31	21.4

3.6 API thinning rate data

API 581 Appendix G (Thinning Technical Module) includes 'Estimated Corrosion Rate Tables' for different kind of steels and alloys in various acidic and basic environments. Collected corrosion rates constructed from Table G-52A converted to SI units are shown on Table 5.

Table 5					
Estimated thinning rates constructed from Table G-52A (API 581) converted to mm/year.					
Material of construction	**482-510**	**510-537**	**538-565**	**565-593**	**593 621**
CS	0.05	0.1	0.15	0.225	0.35
1 ¼ Cr	0.05	0.075	0.1	0.175	0.3
2 1/4Cr	0.025	0.025	0.05	0.1	0.225
9 Cr	0.025	0.025	0.025	0.025	0.025
304SS	0.025	0.025	0.025	0.025	0.025

API thinning rate for 1¼ Cr steel at 538-565 $^{\circ}$C temperature is 0.10 mm per year which is covered by confidence interval of thinning rate on Table 2. This result is interesting given that the conditions in the Loy Yang boiler with its ash soot blowers and high gas temperature would appear to be very different to the conditions API are considering.

3.7 API inspection effectiveness and adjusted TMSF

Appendix 'G' Table (G-6A and B) is used to determine inspection effectiveness. The inspection plan we will consider here is:

Plan 1= (1 fairly +1 usually) inspection every year+1 highly inspection every four year= 2 highly effective inspections every four year
Plan 2= (1 poorly+1 fairly) inspection per year+1 usually inspection every four year=2 usually effective inspections every four year

Table G-7 in Appendix G or Table 9-12 is used to determine TMSF for thinning. These tables are based on a vessel that has a corrosion allowance of 25% of the wall thickness and TMSF. is

adjusted considering 'operational condition' and 'on-line monitoring.' The final results are shown on Table 6. TMSF of over 100 indicates significant risk, so the 20 year old super heater can only be kept in service by the more intensive Plan 1 inspections. Table 7 summarizes all the results for which valid data is available indicating Medium risk ("M") for all cases except for SH2 on inspection Plan 2 where the risk is rated in API 581 as Medium High ("MH").

Table 6

Unit Thinning rate, Initial thickness and Fraction of wall loss

Location	**Boiler age, a**	**Thinning rate (mm/year)**	**ar/t**	**Adjusted TMSF**	
	Years			**Plan1**	**Plan2**
Super heater 2	20	0.1408	0.44	40	160
Super heater 3	16	0.11	0.20	1	20
Economiser	19	0.05	0.17	1	10

Table 7

Final RBI result. Unit 2 SH2 is the one case where inspections cannot preserve the situation after 28 years.
* No data for this case in API 581.
**TMSF before inspection/TMSF after inspection

Boiler and location	**Year (age)**	**Ave ar/t**	***Over Design Factor**	**No of Inspections**	****TMSF Plan 1**	**TMSF Plan 2**
Unit 1 Eco						
	19	0.18	1.31	2	1	10
	23	0.21	1.31	4	1/1	20/2
	27	0.25	1.31	6	1/1	2//1
	31	0.29	1.31	8	2/*	2/*
Unit1SH2						
	19	0.318	1.43	2	4	40
	23	0.385	1.43	4	30/8	80/10
	27	0.452	1.43	6	15/15	30/20
	31	0.519	1.43	8	40/*	40/*
Unit2SH2						
	20	0.44	1.43	2	40	160
	24	0.53	1.43	4	60/40	200/50
	28	0.62	1.43	6	210/210	220/210
	32	0.71	1.43	8	H	H
Unit 4 Eco						
	16	0.30	1.31	2	4	40
	20	0.38	1.31	4	30/8	80/10
	24	0.45	1.31	6	15/15	30/20
	27	0.50	1.31	8	40/*	40/*
Unit4SH3						
	16	0.20	1.67	2	1	20
	20	0.25	1.67	4	2/2	30/2
	24	0.30	1.67	6	2/2	4/2
	27	0.34	1.67	8	4/*	5/-

4 Conclusions

This paper examined ways of analysing tube thickness data to produce an estimate of thinning rate and the life of tubing in power station boilers. A large quantity of tube thickness measurements collected in a coal fire power station in areas of tube subjected to erosion/corrosion was made available to the authors.

There are significant complications:

- Ultrasonic thickness measurements can have significant systematic and random errors. The systematic error measured in the laboratory for ultrasonic thickness meters was an over-estimate of thickness of approximately 0.5 mm.
- The data collected has to be cleansed of faulty data since on occasions the tubes were reported as getting thicker between measurements and some data simply did not conform adequately to the coefficient of determination R^2 when regression analysis was conducted
- Initial thicknesses of the tubes are often poorly known.

Given these issues the data can eventually be used to predict an expected life for a group of tubing using the authors' "warning level" method. This uses a 95% confidence interval for thinning rate and a warning thickness equivalent to two inspections prior to failure. The loss of useable life by two inspection periods occurs (the loss is about 20% in the case quoted).

The methods developed by the American Petroleum Institute in API 581 were also investigated. These produce similar kinds of life estimates using somewhat different and more complex approach.

5 Acknowledgements

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SESSION 13: BTF Reduction Programs

Chairman: R. Micko, Entergy

Characteristics of "World Class" Boiler Tube Failure Reduction/Cycle Chemistry Improvement Programs

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Abstract

Boiler tube failures and other equipment cycle chemistry corrosion and deposition problems continue to be the primary causes of availability and performance losses in fossil power generating plants worldwide. In the U.S. equivalent availability losses (EAL) due to BTF problems alone, continue to average around 2.5% annually. Why is it that some utility systems or plants are able to maintain an EAL due to BTF of 1% or less on a continuous basis, while others continue to incur losses in excess of 2.5%? Why is it that some utilities experience many plant cycle chemistry-influenced corrosion and/or deposition problems over time and others do not? This paper describes how some utilities, having implemented EPRI's integrated Boiler Tube Failure Reduction/Cycle Chemistry Improvement (BTFR/CCI) Program have been able to achieved "world class" performance in both BTFR and CCI within the first two to three years of program implementation. A "world class" BTFR/CCI Program can simply be defined as one that achieves and maintains an equivalent availability loss (EAL) due to BTF of < 1% for an indefinite period of time, and experiences very few, if any, plant cycle chemistry-influenced corrosion and/or deposition problems over the life of the plant. Described herein are the BTFR/CCI Program characteristics common to "world class" achievers, compared to those of Programs that have been less successful, or failed to achieve, similar results.

Introduction

EPRI initiated the first "Boiler Tube Failure Reduction (BTFR) Program" in 1985. Its primary goal was to demonstrate that the availability of fossil-fired boilers could be significantly improved by the implementation of a formalized BTFR program. Sixteen utilities, representing approximately 60,000 MW's participated in the demonstration program. This five-year program was very successful. Reductions of EAL due to BTF of 1.5 to 4.5% were demonstrated. The results of this program are well documented [(1)]. Also, results of EPRI cycle chemistry research studies, International conferences and member input indicated that cycle chemistry-influenced equipment deposition and corrosion problems have

been increasing, and represent more than 50% of total fossil plant availability and/or performance problems. Based on these findings, EPRI followed this very successful BTFR program with a "Cycle Chemistry Improvement (CCI) Program" in September 1992. Its primary goal was also to demonstrate that availability and performance losses in fossil plants, due to corrosion and deposition problems, could also be significantly improved by the implementation of a similar formalized CCI Program. Nine utilities, representing approximately 48,000 MW's participated in this demonstration program. Availability improvements up to 4% were also demonstrated, with reductions in operating costs in excess of $3,000,000/yr. The results of this program are also well documented [(2)]. In 1995, at the recommendation of their members, these two programs were then integrated into a single BTFR/CCI Program. Since that time, more than 70 utility organizations around the world have implemented and/or received training in the integrated BTFR/CCI program. The organizations range in size from single plants to 40,000 MW systems. The purpose for program implementation was either to reduce large equivalent availability losses (EAL) due to BTF, usually above or equal to the National average of 2.5%, or to maintain a present low level of EAL, i.e. < 1.0%. EAL due to BTF is defined as all forced and maintenance outages, and main steam pressure or temperature derates due to BTF. For some of those utilities with high EALs due to BTF, tremendous benefits have resulted for programs that have been implemented for two years or more. Examples are discussed in (3). Cost savings have ranged as high as $37,000,000/year. The remainder of this paper briefly describes those characteristics common to units, plants and/or systems that have achieved "world class" Program status, as determined by EPRI's BTFR and CCI benchmarking processes described in [(3)].

What are "World Class" BTFR/CCI Programs?

A world class integrated BTFR/CCI Program can be simply defined as one that maintains an EAL due to BTF of < 1% over long periods of time, and experiences very low availability and/or performance losses or costs due to plant corrosion or deposition problems over the life of the plant. They appear to be immune to many reasons typically given by many utility personnel for continuing or never ending BTF or CC problems, such as: it's "the nature of the business" as boilers, turbines, feedwater heaters or condensers become older, enter cycling or peaking duty, burn "spot" or cheaper fuels, are under designed to carry expected loads, etc. Needless to say they aren't immune to these influences, they are just superbly managed to reduce or negate their short- as well as long term impacts. **Jack Welch, ex-chairman of General Electric, was asked by an Investor's Business Daily reporter, "How does a manager balance the short term expectations of Wall Street with a longer-term more strategic view? To this he replied, "That's what managing is all about: balancing the short and long". That's what leaders are paid to do. You make decisions that certainly push for short-term performance at times, while never neglecting to invest in R&D and other things for the long-term".** The same could be said for successful BTFR/CCI Programs. Management has to make tough decisions for the short-term, such as "running with known tube leaks, or making quick pad

weld repairs during serious system conditions", but the long-term requires strong adherence to operating and maintenance "standards" of not doing so, when system conditions don't necessitate it. The characteristics of world class integrated BTFR/CCI Programs are described below. Where possible, the authors have indicated the differences between the more versus less successful programs.

Characteristics of "World Class" Integrated BTFR/CCI Programs

Achieving "world class" performance in BTFR and CCI does not occur overnight. It usually takes two to three years, or longer if resources are limited. Implementation of EPRI's integrated BTFR/CCI Program usually takes place in two stages. The implementation strategy for EPRI's integrated BTFR/CCI Program has been well documented [(1)].

Typically, before a utility decides to implement the Program, it goes through a self-assessed "discovery" process. During this exercise, the utility gathers industry and/or in-house data and acknowledges that its performance in these areas, as compared to Industry leaders, is at best only average or "appalling" (as defined by EPRI's evaluation criteria). Accepting the fact that it has problems in these areas, it then seeks to answer three primary questions: "Why does our performance differ significantly from that of Industry leaders?" "What do we wish our performance to be in the future?" and, "What do we have to do to get there?" Based on these findings, and a desire to achieve world-class performance for some or all of its plants in the future, it then decides to implement EPRI's proven integrated BTFR/CCI Program.

The first stage or period can be defined as "moving towards world class". This is when the utility's Program organization, consisting of corporate BTFR and CCI Program coordinators and plant teams, is in place, and a "corporate directive" has been developed and signed by senior management. This document is typically referred to during subsequent training of corporate and plant personnel, to clearly demonstrate senior management's commitment to the Program. The authors have found it to be the single most important requirement for all successful Programs. Corporate and plant team personnel can now be trained, begin to define and rank their serious BTF and CC problems, and to develop plant-specific action plans to move towards corporate's goal of achieving "world class" in both areas, within a given time frame.

The second stage or later period can be defined as implementing those practices essential to consistently "maintaining world class" performance in these problem areas for an indefinite period of time. The characteristics of "world class" integrated BTFR/CCI Programs are described below separated by stages, and those aspects specific to BTFR and CCI.

First we will cover "world class" Program characteristics in the area of BTFR.

"World Class" Program Characteristics in the area of BTFR

Stage 1 - "Moving towards world class" in BTFR

The following Program characteristics are focused on: kicking off the Program with visible evidence of senior management support; raising the level of knowledge of corporate and plant teams through training; clearly defining current unit, plant and system costly BTF events or "repeat" problems, in terms of mechanism identification, root cause(s), %EAL, lost MWhrs and/or costs; and developing action plans to substantially reduce their future impact or permanently correct them.

- **Clear direction to corporate/plant management, engineering, operations and maintenance personnel on the conduct of day-to-day activities that influence BTF**

  Most successful Programs

  A Program corporate directive or "philosophy statement" is written and signed by senior management, that gives clear direction to corporate and plant management, engineering, operations and maintenance personnel on the proper conduct of specific day-to-day decisions and/or activities that influence BTF.

  To support the corporate directive, plant management issues plant-specific operating and maintenance procedures to control day-to-day activities that influence BTF.

  Less successful Programs

  The statements in the corporate directive are never transformed into plant-specific operating and maintenance procedures to control those day-to-day activities that influence BTF.

- **Training of corporate/plant management, engineering, operations, maintenance and chemistry personnel in all "controllable" aspects of BTFR.**

  Most successful Programs

  Have the maximum possible number of corporate and plant management, engineering, operations, maintenance and chemistry personnel trained in the "controllable" aspects of BTFR. Training starts with management, with the first training session being kicked-off by the senior Vice-President of Generation/Production, and attended by managers from Corporate Operations and Technical Support, and all Regional Directors and Plant

Managers. Multiple subsequent two-day mixed sessions, (number depending on utility size and/or number of plants) soon follow, and are attended by corporate and plant staff, and other engineering, operations, maintenance and chemistry personnel, who will make up the corporate and plant teams, such that each will have a good understanding of not only their role in the BTFR Program, but also that of the other attending personnel.

Less successful Programs

Very few senior corporate, Regional or plant management are trained, and only a few plant operating personnel are trained. BTFR is primarily viewed as an engineering and/or maintenance responsibility.

- **Knowledge of the EAL and costs due to BTF**

Most Successful Programs

World-class utilities know the EAL due to BTF for each unit, plant, and for the entire system. They track these numbers on an annual and rolling twelve-month basis. The rolling twelve-month plot gives a true indication of the current trend.

EAL due to BTF = EFOR (BTF) + EMOR (BTF) + Derates (BTF)

They also know the real-time generation (fuel transfer) costs associated with BTF.

Less Successful Programs

BTF generation costs aren't actual. An average cost in $/MWhr, based on historical data, times lost MWhrs due to BTF is used. They tend to track only the total unit, plant and/or system EFOR, and don't separate that contribution specific to BTF's such that Program-specific goals can be set.

- **BTF problems are ranked in terms of equivalent availability loss (EAL), lost Mwhrs and generation costs**

Most successful Programs

Plant-specific BTF problems are documented in terms of: Unit #, # of BTF's, and failure mechanism. They are then ranked by seriousness, i.e. by "repeat" BTF's or single events, by %EAL, Lost MWhrs or costs, with action plans to address them (Table 1.). Plant inputs are then used to derive and rank a complete System listing of major BTF problems, so senior management knows which BTF problems on a system basis, when corrected, will yield the biggest return on its investment.

Plant	Unit	#BTF	Circuit	Mechanism	EAL (%)	Generation Costs (10^3)	Action Plan(s)
JPD	1	4	WW	Thermal Fatigue[C]	1.37	$7,200	P-0001
JPD	1	3	SH	Long-term OHC[C]	1.64	$4,032	P-0002
JPD	2	3	WW	Hydrogen Damage[C]	1.23	$3,974	P-0003
JPD	2	4	EC	Corrosion Fatigue[N]	1.37	$3,840	P-0004
JPD	1	1	RH	Fireside Corrosion[C]	1.32	$3,712	P-0005
JPD	3	2	RH	Flyash Erosion[C]	1.14	$3,120	P-0006
JPD	4	2	WW	Corrosion Fatigue[N]	0.73	$2,304	P-0007
JPD	2	1	WW	Sootblower Erosion[C]	0.68	$1,680	P-0008
JPD	4	2	EC	Flyash Erosion[N]	0.64	$1,612	P-0009
JPD	3	1	SH	Short-term OH[N]	0.57	$1,240	P-0010
C - means continuing from 2002				**N – means new in 2003**			
Totals	23				2.67	$32,715	

Table 1. Typical Plant BTF Report for FY2003

Less successful Programs

Plant BTF's are documented chronologically and by circuit, not by mechanism, or grouped together as serious repeat or single event BTF's, in terms of %EAL, Mwhrs or costs.

- **Senior corporate and plant management are committed to mechanism identification, root cause analysis and permanent corrective action for all BTF.**

Most successful Programs

This program characteristic is **the** cornerstone for all successful programs. Best plant teams carry out each of these essential activities for every BTF. If a forced outage occurs during a serious system condition, where a piece of damaged or failed tubing couldn't be removed for verification of the mechanism by a metallurgist because of time constraints, it is removed at the next suitable outage opportunity to do so. Correct mechanism identification is essential for root cause analysis. Determination and permanent correction of the root cause (that which activates the mechanism in the first place) "kills" the mechanism, such that a repeat failure will not occur in the future.

Less successful Programs

Not being committed to any one or more of these three critical activities is the most common deficiency of less successful programs. Failure to have BTF mechanisms verified by metallurgical examination for one reason or another frequently results in incorrect root cause analysis because plant team personnel determined the wrong mechanism. Incorrect root cause analysis typically results in wrong solutions. Wrong solutions usually result in future repeat BTF.

- **Solving BTF problems is best performed by a "plant team" not by a boiler engineer or metallurgist**

Most successful Programs

BTF problem solving is performed as a "team" activity. It isn't primarily a boiler engineer, maintenance foreman or metallurgist's responsibility. If the actual root cause is due to an operating boiler-tube-damaging process condition, how do boiler engineers, maintenance foremen or metallurgists know what the actual root cause is? Mechanism verification is where metallurgists excel. Boiler design is where boiler engineers excel. Control of process conditions is where operators excel.

Less successful Programs

Root causes of BTF problem solving is thought to be too difficult for an operator or boilermaker to understand. Only boiler engineers or metallurgists are capable of reading and comprehending "what's in the book".

- **Action plans are prepared for every "repeat" BTF problem or serious single BTF event.**

Most successful Programs

Two separate action plans are prepared for every BTF problem, be it a single serious BTF event or multiple "repeat" BTF that address: (1) disposition of damaged tubing, due to the same primary failure mechanism and close to failure, that still remains in the boiler, and (b) correction of the root cause(s) that activated the mechanism in the first place.

Less successful Programs

Emphasis is primarily on an action plan to replace the damaged tubing. Action plans to correct the root cause are usually neglected.

- **Correcting the root cause ("killing" the mechanism), rather than "managing damage" from overhaul to overhaul.**

  Most successful Programs

  Best Programs have demonstrated, that in the long run, it is usually more cost effective to correct the root cause rather than to attempt to manage damage over a long period of time. Managing damage may save some money in the short-term, but, not only does it guarantee revisiting the damage location in the future but it also raises the risk of future repeat BTF because we didn't get back to check the area for damage in time. This philosophy permits much longer periods between scheduled outages, without worrying about whether the bandage might or has come off! World-class utilities use the technology available today (6) to correct the known root causes of almost all common BTF problems.

  Less successful Programs

  Corporate and/or plant management is reluctant to believe the experience of others and takes the short-term "managing damage" approach to minimizing repeat BTF problems and costs.

- **BTFR Program goals are multidimensional such that short-term and long-term goals are not in conflict but in concert with the overall corporate goal of consistently maximizing shareholder return.**

  Most successful Programs

  Management does a superb job of balancing short-term single-dimensional goals like EFOR, EAL, MWhrs, O&M costs, with the long-term Program goal of achieving and/or maintaining "world class" performance in this area indefinitely. Rewards and/or compensation are in concert with management's ability to maximize both short- and long-term plant performance. The best "short-term goal, that's in concert with a long-term Program goal of world class, is "peak period reliability". Maximizing performance during this "serious system condition" period is only possible, if plant management and the plant team are in sync with what has to be done during low cost BTF forced outage opportunities, to minimize the probability of future BTF forced outages.

  Less successful Programs

  Corporate and/or plant management emphasis is primarily on short-term one-dimensional goals.

- **A complete "paper trail" exists for every "repeat" or serious single event BTF problem that defines and verifies the BTF mechanism and**

root cause(s), and includes separate and distinct action plans to (a) eliminate or mitigate the rate of BTF, and (b) to correct the root cause(s) such that BTF's won't reoccur in the future.

Most successful Programs

Every BTF problem, be it a single serious BTF event or multiple "repeat" BTF, is completely understood and documented in terms of mechanism identification and verification, root cause(s) and verification, and corrective actions with two separate action plans to address: (1) damaged tubing due to the same primary failure mechanism, close to failure and still remaining in the boiler, and (b) correction of the root cause(s) that activated the mechanism in the first place.

Less successful Programs

Have little mechanism and/or root cause(s) verification documentation, and give primary emphasis to documentation necessary for replacement of damaged tubing with little attention to that required for permanent correction of the root cause(s).

Stage 2 - The "Maintaining World Class in BTFR Indefinitely"

The following characteristics are focused more on preventing future rather than reacting to current BTF's. They have become an integral part of the utility's culture in how the "team" responds to a current BTF, or the short- and long-term action it takes to prevent future ones. "Repeat" BTF's are a thing of the past, in that they are now rare rather than frequent. Operating and maintenance procedures (in concert with system conditions) that can influence future BTF's are strongly adhered to. They are geared to finding damaged tubing early, and totally committed to determining the mechanism and correcting the root cause(s), such that future forced outages due to BTF's are an infrequent rather than common occurrence.

- **Performing condition assessments of superheaters (SH) and reheaters (RH) using the oxide scale technique within the last ten years.**

  Most successful Programs

  The only way to achieve an EAL due to BTF of < 1% over a long period of time on a consistent basis is by finding damaged tubing in any circuit early, such that planned replacement, or "killing of the mechanism" by correcting the root cause, can take place before forced outages due to failures occur. Best programs, not only do complete profiles of SH and RH, but also extend coverage of condition assessments to all other circuits and include all likely mechanisms and typical locations in these other circuits, which experience

from “the book” has shown to result in BTF. This is the only way to prevent what seems, to some utilities, to be a constant stream of future BTF “surprises” from failure mechanisms that “we have never seen before”.

These Programs also have a very high percentage of SH and RH examined using the oxide scale technique, i.e. typically higher than 75-80% and 100% for “world class” organizations.

Less successful Programs

Less successful Programs simply react to current SH or RH BTF problems. During a forced outage, they only look for collateral damage and/or damage from the same primary mechanism, around the location of the BTF that caused the outage. During scheduled outages, they only inspect in locations, and/or for damage from mechanisms that have resulted in current or past BTF.

These Programs typically still rely on sample removal to determine the oxide scale thickness and/or to determine the wall loss.

- **Only considers “easing” maintenance “standards” during periods of very serious system conditions.**

Most successful Programs

Making expedient and/or cheap pad, window-weld, or weld buildup repairs during forced outages, rather than replacing damaged or failed tubing with a new section, is highly discouraged and strongly controlled through use of maintenance procedures, that are in concert with satisfying both the immediate or short-term “serious” needs of the system, while at the same time, maintaining the long-term “world class” availability and performance “standards” of the plant (Table 2).

Less successful Programs

These practices are either not strongly controlled by maintenance procedures, or the “system status” at the time of the BTF forced outage is not defined, or always considered by plant management to be very serious, and quick pad- or window-weld repairs are therefore made.

System Status or Condition			
Mechanism Damage	Green	Yellow	Red
Low Risk*	Replace	Padweld if replacement increases time > 8 hr	Padweld, replace later
High Risk*	Replace	Replace	Padweld, replace later

Table 2. Repair Decision Table

* High risk mechanisms are typically considered to be those with: microstructural damage due to high temperature creep, dissimilar-metal-welds, graphitization, short term overheating or hydrogen damage; or "crack" damage due to corrosion or thermal fatigue, stress corrosion cracking or supercritical-waterwall-cracking.

* Low risk mechanisms are typically those due to erosion or corrosion.

- **Using BTF forced outages as "investigation opportunities", system conditions permitting", to optimize scheduled outages.**

Most successful Programs

Have sufficient resources and are prepared to use every moment of a forced outage, based on time allocated due to system conditions, to carry out a "BTF Forced Outage Plan" (Table 3.). The purpose of this plan is to minimize the probability of a "repeat" BTF, I.e. Another forced outage in the same boiler, same circuit, by the same mechanism and root cause, when the boiler is returned to service. Plant BTFR team personnel, in parallel with welders/boilermakers making the actual repairs, perform the activities on this checklist.

Less successful Programs

Fail to get much further than the first step of surveying the location of the primary failure and fixing the failure and any collateral damaged tubing associated with it. The investigation is left to the Boiler Engineer and maintenance personnel or the contractor. Operators aren't involved in the BTF investigation process.

System Condition			Team Activity
Green	Yellow	Red	
			1. Survey Area of Primary Failure
			1.1 Identify location of primary failure
			1.2 Identify primary failure mechanism
			1.3 Develop possible root causes
			1.4 Identify most probable root cause
			1.5 Determine extent of damage on failed tube
			1.6 Determine extent of collateral damage (wash, etc)
			2. Develop Repair Instructions
			2.1 Determine type of repair for primary failure
			2.2 Determine type of repair for collateral damage
			3. Identify Other Locations Susceptible to Same Mechanism and Root cause
			3.1 Perform limited inspection of other areas susceptible to same mechanism and root cause
			3.2 Identify tubing damage
			3.3 Determine remaining life of damaged tubing
			3.4 Develop repair instructions
			4. Inspect Other Historical Problem Locations for Tubing Damage
			4.1 Review previous boiler inspection data
			4.2 Perform limited inspection of other historical problem areas for tubing damage
			4.3 Identify tubing damage
			4.4 Determine remaining life of damaged tubing
			4.5 Develop repair instructions
			5. Complete Documentation
			5.1 Complete BTF Report
			5.2 Develop action plan for replacement of damaged tubing
			5.3 Develop action plan for correction of root cause

Table 3. BTF Forced Outage Plan Checklist

- **Only <u>considers</u> "easing" operating "standards" during periods of very serious system conditions.**

<u>Most successful Programs</u>

Recognizes the need to clearly define "system conditions" (Table 4) such that plant management can make the tough operating and/or maintenance decisions in the short term when system conditions are very serious, while at the same time, they can make good long-term decisions when they are not.

System Condition	Green	Yellow	Red
Economic	System Clearing Costs < $20/MWhr	System Clearing Costs $20-$50/MWhr	System Clearing Costs > $50/MWhr
Reliability	System Normal Level 0	System reliability Alert Level 1	Capacity Curtailment Level 2 or above
Environmental	Emission Goals on Target	Emission Goals may not be met	Projected to exceed Emission Goals

Table 4. System Condition Criteria

Leak Area	Leak Size	System Condition		
		Green	Yellow	Red
SH	Minor	Can delay up to 8 hrs	Can delay up to 16 hrs	Delay no more than 7 days
SH	Moderate	Can delay up to 8 hrs	Can delay up to 16 hrs	Delay no more than 7 days
SH	Major	Shutdown < 2 hrs	Shutdown < 2 hrs	Can delay up to 8 hrs
RH	Minor	Can delay up to 8 hrs	Can delay up to 48 hrs	Delay no more than 7 days
RH	Moderate	Can delay up to 8 hrs	Can delay up to 48 hrs	Delay no more than 7 days
RH	Major	Shutdown < 2 hrs	Can delay up to 8 hrs	Can delay up to 8 hrs
EC	Minor	Can delay up to 24 hrs	Can delay up to 7 days	Delay no more than 7 days
EC	Moderate	Can delay up to 24 hrs	Can delay up to 7 day max	Delay no more than 7 days
EC	Major	Shutdown < 2 hrs	Can delay up to 4 hrs	Can delay up to 8 hrs
WW	Minor	Can delay up to 7 days	Delay up to 14 days max	Delay no more than 14 days
WW	Moderate	Can delay up to 7 days	Can delay up to 7 days	Can delay up to 7 days
WW	Major	Can delay up to 48 hrs	Can delay up to 72 hrs	Can delay up to 72 hrs
Minor = No noticeable increase in makeup water				
Moderate = Increase in makeup water of < 1”/hr				
Major = Increase in makeup water of > 1”/hr				

Table 5. Operating Procedure to “Run with known tube leaks”

Operating the boiler in any “boiler tube damaging process condition, such as: “running with known tube leaks, under severe slagging or fouling condition, with high tube metal temperatures, or a “core” cycle chemistry parameter outside of limits is discouraged, and strongly controlled through use of operating procedures that are in concert with both satisfying immediate “serious” needs of the system, while at the same time maintaining the long-term “world class” availability and performance “standards” of the plant (Table 5).

Best operating shift performance is recognized as “that shift that is able to control all critical water, steam and combustion parameters, such that the unit experiences “the minimum time under all boiler tube damaging process conditions; and, combustion, steam and/or water process limits rather than equipment limitations, are used to determine the maximum load limit under all but very serious system conditions.

Less successful programs

Boiler tube damaging process conditions are either not strongly controlled by operating procedures that are in concert with system needs at the time, or the "System Condition" at the time the boiler is experiencing a boiler tube damaging process condition, or forced outage due to a BTF, is poorly defined.

"World Class" CCI Program Characteristics

Stage 1 - "Moving towards world class" in CCI

The following Program characteristics are focused on clearly defining current serious single event or "repeat" CC-influenced equipment problems due to corrosion or deposition, in terms of mechanism identification, root cause(s), lost MWhrs, BTU's/KWhr, BTU's/hr and/or costs; and, developing action plans to substantially reduce their impact or to permanently eliminate them.

- **Knowledge of lost MWhrs, BTU's/KWhr, BTU's/hr and costs due to equipment CC-influenced corrosion and/or deposition problems**

  Most successful Programs

  World-class utilities know what their plant-specific CC-influenced equipment corrosion and/or deposition problems are, and their associated indirect costs. Indirect CC costs are best tracked on a rolling 24 months or longer period.

  Being as cycle chemistry corrosion and/or deposition problems can influence the availability and/or performance of almost every piece of plant equipment, the overall impact of cycle chemistry equipment problems isn't very well known or documented.

- **CC corrosion and/or deposition problems are ranked in terms of equivalent availability (%EAL or MWhrs) or performance losses (BTU's KWhr or BTU's/hr), and their associated indirect costs**

  Most successful Programs

  All CC corrosion and deposition "repeat" problems or major single events, are clearly defined and ranked, by the plant Program teams, in terms of unit, component, %EAL contribution, lost MWhr's, and cost; where "repeat" CC problems are defined as the same availability or performance loss caused by the same deposition or corrosion problem and root cause, over and over again; such as, condenser leaks, BTF (where the mechanism is CC-influenced), delays on startup, etc. These unit and/or plant CC problem rankings are then submitted to the corporate Program coordinator, who then generates a corporate CC problem ranking for the system.

Less successful Programs

CC-influenced equipment availability and/or performance loss problems tend to be associated only with a particular piece of equipment rather than as a cycle chemistry problem; such as, a BTF due to hydrogen damage, where the root cause is actually due to incorrect feedwater chemistry and a neglected source of contaminant ingress.

- **Cycle is designed for "world class" performance**

Most successful Programs

Cycle contains: titanium or very tight condensers (with ability to maintain condensate cation conductivity of < 0.2uS/cm), all-ferrous feedwater heaters, deaerating heaters, and condensate polishers. Air inleakage is maintained to give dissolved oxygen at the condensate pump discharge of < 10ppb .

Less successful Programs

Condensers aren't tight. Small amounts of cooling water ingress or large amounts of air inleakage are tolerated. Feedwater heaters have mixed metallurgy, and/or they don't have condensate polishers.

- **Every unit has EPRI's recommended "core" level of cycle chemistry instrumentation for unique cycle diagnosis**

Most successful Programs

Every unit, regardless of its operating role, i.e. base-loaded, cycling or peaking, has EPRI's recommended "core" level of instrumentation installed.

Less successful Programs

Usually only provides base-loaded units with EPRI's recommended "core" level of cycle chemistry instrumentation.

- **Has cycle chemistry process limits, action levels, and operating procedures for all modes of operation**

Most successful Programs

Have determined unit-specific process limits, action levels and operating procedures, and operators are trained on how to respond to most common "cycle chemistry excursions" for all modes of operation, including startup, shutdown and layup.

Some have installed EPRI's "ChemExpert" for 24/7 chemistry technical coverage and/or support.

Less successful Programs

Have adopted EPRI's generic process limits and action levels.

- **Optimized the feedwater and boiler water chemistry of all units over the life of the plant**

Most successful Programs

Continuously challenges the status quo of the cycle chemistry treatments being used over the life of the plant. Are on either All-Volatile-Treatment-Oxidizing (AVT (O)), or Oxygenated Treatment, (OT). Many justified improving chemistry, i.e. changing from phosphate to AVT, or AVT to AVT (O), or AVT to OT, or equipment, i.e. have changed out copper to all-ferrous feedwater heaters, etc., using EPRI's benchmark to value process described in (3).

Less successful programs

Don't continuously challenges the status quo of the cycle chemistry treatments being used. Consider it satisfactory to operate with a particular treatment "because we've always done it that way".

- **Has a comprehensive cycle chemistry layup strategy for short- and long-term shutdowns of the units**

Most successful Programs

Recognize that the majority of corrosion product generation takes place during unit shutdowns, and therefore, has a strategy using wet chemistry or dry air to protect equipment surfaces during these periods.

Stage 2 - "Maintaining World Class CC Indefinitely"

The following CC characteristics are focused more on preventing future plant corrosion and deposition problems rather than reacting to them. They have also become an integral part of the utility's culture in how the "team" responds to a current CC excursion or event, or the short- and long-term actions it takes to prevent future ones. Availability or performance losses due to corrosion or deposition are a thing of the past, in that they are now rare rather than frequent. Process chemistry limits, action levels and operating procedures (in concert with system conditions) are strongly adhered to, such that contaminant ingress isn't tolerated, and time under any equipment damaging CC process conditions is minimized.

- **Chemical cleaning frequency is typically > 10 years**

  Most successful Programs

  Need to chemical clean a boiler is based primarily on “dirtiness”. The root cause(s) of corrosion product generation and transport have been solved, such that rates of iron or copper corrosion generated or transported are less than 2 ppb.

  Less successful Programs

  Prefer to manage the level of corrosion product generation, transport and deposition in the boiler by chemical cleaning every 3-4 years on a routine basis, rather than correcting the root cause(s) for having to clean in the first place.

  Zero CC-influenced equipment corrosion or deposition problems

  Most successful Program

  Equipment failures or performance losses due to CC corrosion and/or deposition problems rarely occur.

Conclusions

Given today's knowledge and experience with most common BTF and CC problems that impact the availability and performance of fossil-fired plants, and EPRI’s technology[5&6] and proven programmatic approach to BTFR and CCI[1,2 &3], there is only one reason for a utility not achieving “world class” BTFR and CCI rankings for its core generating units. That reason is **“management’s failure to balance the short- and long-term management aspects of BTF and CC corrosion and/or deposition problems”, i.e. being fully committed to making tough decisions for the short-term, such as “running with known tube leaks, or making quick pad weld repairs only during serious system conditions”, while at the same time, for the long-term, requiring strong adherence to operating and maintenance “standards” of not doing so, when system conditions don’t necessitate it.** Twenty years of Program experience have also demonstrated that significant cultural changes in present management, engineering, operations and/or maintenance policies and/or practices are usually required for a utility or plant to become world class. The characteristics of the “world class” BTFR/CCI programs described above clearly indicate where those cultural changes are necessary. If any utility wishes to see how close they are to being world class in these areas, simply take the “evidence test” and see how many of the characteristics of world class Programs just described, they currently practice.

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HOOSIER ENERGY MEROM GENERATING STATION'S EXPERIENCE WITH BTF AND CYCLE CHEMISTRY IMPROVEMENT

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1.0) ABSTRACT

This paper reviews Hoosier Energy's experience with EPRI's Boiler Tube Failure Reduction and Cycle Chemistry Improvement Program. Prior to September of 2001, the Merom Station did not have a formal tube failure reduction and cycle chemistry improvement program in place. At that time, the station's focus on tube failures was more reactive. Since the implementation of the program, the program team has become more aware of the existing mechanisms on each unit and has developed both short and long term plans for stopping the active mechanisms. In addition, the Station's BTF% has dropped by over three percent.

The paper will also review how the program is structured and what groups are involved. Pre-program data through the final scheduled review will also be presented along with the team's plans for continuing the program. Finally, team member functions, documentation, and reporting will also be reviewed.

2.0) INTRODUCTION

Hoosier Energy R.E.C., Inc. is a generation and transmission utility system owned by 17 member system cooperatives. Hoosier Energy owns and operates the Merom Generating Station located in Sullivan, Indiana. The Merom Station is a steam-cycle electric generating plant with two 490 net megawatt coal-fired units. The boilers were manufactured by Riley Stoker Corporation and have been in operation since about 1981. Each boiler supplies steam to two Westinghouse boiler feed pump turbines along with a Westinghouse turbine generator set. The Riley Stoker boilers were built for maximum drum design pressure of 2,900 psig and are capable of producing 3.9 million lbs/hr of steam at 2,630 psig and 1005 degrees F.

3.0) PRE-PROGRAM TUBE FAILURE HISTORY

Prior to September of 2001, the Merom Station did not have a formalized program for the reduction of tube failures. The station was approaching twenty years of service and its components were beginning to show their age. Tube leak occurrences had increased during the 1999 and 2000 years and were on the rise again in 2001. In addition, the increased number of leaks was noted to be occurring on both units and the majority of the leaks were in similar locations. The Station ended 2001, with twenty-one total leaks, a BTF percentage of 5.08, and nearly nine hundred hours of down time. Of the nearly nine hundred hours, one unit had been off line for an equivalent of over a month's duration.

At the same time, the power market had changed dramatically and station reliability had become extremely important for all utilities. For Hoosier Energy, unit reliability was all the more important given its smaller size. Prior to any gas turbine additions, one of the Merom Station units was approximately forty percent of Hoosier Energy's total generating capability. Given the power market fluctuations and the amount of station down time experienced due to tube leaks, Hoosier Energy needed to make changes and decided to utilize EPRI's Boiler Tube Failure Reduction and Cycle Chemistry Improvement Program as a starting point.

Prior to beginning the program, the typical repair strategy included the notification of System Control of a tube leak and deciding when the unit would be taken out of service to make the repairs. The unit may have remained in service for a few hours and even up to a few days depending on the power market. Once out of service, the outage coverage included a two man boiler team from the engineering department on a twelve hour shift rotation until completion of the repair. Both temporary and permanent repairs were made during the outages depending on the power market at the time of the leak. Pad welding was often used as a means for returning the unit to service quickly. At this time, the Station was taking a more reactive approach in making boiler repairs and was without specific goals for reducing the number of failures.

4.0) EPRI'S INITIAL STATION REVIEW

EPRI's initial on site review of the Station's tube leak program occurred in September of 2001. Prior to the review, station personnel had collected all of the available historical tube leak data. At that time the data included the number of tube leak hours for each unit along with the associated contributions from each section of the boilers. Graphs showing the sections causing the most down time were also provided along with the available third party failure analysis results from several tube leaks. Merom had been using the historical data to prioritize expenditures during the

stations scheduled outages. Since tube leaks were the highest reliability impact for the Station at that time, funding was often shifted in an attempt to reduce the number of tube leaks and improve reliability.

From the initial review, it was noted that though the Station did have a large collection of historical data, appropriate information on the various types of failure mechanisms was not available. For failure reductions based on root cause, EPRI had pointed out that the number of active failure mechanisms on each unit and whether they were temperature or cycle chemistry related was very important. Future repairs based on incorrect mechanisms could lead to repeat failures as time progressed. EPRI also noted the Station did not have an official failure reduction team with representation from the various groups necessary to operate a generating facility. A program plan with upper management's approval was also not present. Finally, additional items missing from the station's program included various check sheets, tube leak reports, and details of repair strategy based on the power system status.

Based on the initial review, EPRI rated the boiler portion of the existing Merom Station program in the below average category. The Station's cycle chemistry portion was rated in the average category. EPRI has five categories to define a Station's program status. The categories include below average, average, good, very good, and world class. The existing Merom Station program had been rated initially as fairly ineffective. Upon the review, the Station personnel committed to begin making the suggested changes and to schedule program status reviews every six months.

5.0) MEROM'S PROGRAM DEVELOPMENT

After the initial review, the Station took steps to form an official program team and to develop a program plan for approval by Hoosier Energy's upper management. The plan outlined new procedures for removing units from service with a known tube leak and included what types of repair methods were to be used during tube leak outages. The new plan was approved and signed by the Vice President of Operations for Hoosier Energy. Per EPRI's suggestion, the team that was developed included members from operations, engineering, maintenance, chemical labs, planning and scheduling, and headquarters.

One of the first items completed by the new team was the development of an action item listing from the initial review. The team essentially took all of EPRI's suggestions and made them action items for the team. The action item listing included the date assigned, the task, the responsible team member/s and the due date for each item. Suggestions by EPRI during the future team reviews were also added to the listing as the program continued.

The team began meeting monthly and based discussions on a pre-meeting agenda that was focused on any tube leak occurrences since the last team meeting. After each leak, team members completed EPRI's tube failure report. Each report includes the leak location, downtime and megawatt hour impact along with suspected failure mechanism. Failures without a clear cut mechanism were then sent out for further analysis and verification. During each meeting a copy of all prior leak reports along with any associated documentation such as pictures were given to each team member for discussion.

Meetings also consisted of an action item status review. To aid the team in becoming more fluent with the types of mechanisms that can cause tube failures, the team also began reviewing a chapter from EPRI's tube failure volumes. Each month a different team member is assigned to summarize and talk through a specific chapter with the team. Meetings held directly after a scheduled outage also include copies of all completed boiler inspection, repair, and replacement summaries for discussion.

6.0) ADDITIONAL PROGRAM DEVELOPMENT

As time progressed the Station's program documentation began to increase and changes were made to the Station's procedures for operating with a known leak and how it was to be repaired. New documentation included tracking tube leaks not only by section but by the specific mechanism. This documentation also included whether the leak was a repeat failure or a new occurrence. Once the known active mechanisms had been identified and separated for each section of the boilers, action plans were developed for both short and long term repairs of each mechanism. Each action plan had a separate short and long term plan defined including the necessary budget amount to implement the plan. The team also developed a tube leak outage checklist with assignments for various members of the team along with the expected duration of each activity in the checklist. This listing also included a Hoosier Energy oriented system status rating and the tube leak repair plan modifications based on that status. Again, when Hoosier Energy began the program, one of the Merom units was approximately forty percent the available generation. Other utilities had developed a system status rating based on low, intermediate, and high levels of purchase power risks. With Hoosier Energy, the system status really only included intermediate and high risk categories. Purchasing power on the open market occurred any time one of the Merom Station units was off line.

The changes to operating and repair procedures included how quickly the unit was removed from service after a tube leak had been verified and the appropriate repair methods to be used. Once the team was developed and the program underway, the units began being removed from service within about one hour of determining there was a leak. With this change, a

tradeoff was realized by removing the units from service in a more timely manner. Depending on the location of the leak, serious collateral damage can occur very quickly. However, removing a unit from service too soon can lead to additional down time due to difficulty in finding the leak. From this realization, a further modification was made to this procedure. If the leak is noted to be small and suspect for being easily located, program team members are asked to travel to the site for verification that the leak can be found. Finally, Repairs of all known leaks were to be completed via replacement unless the system condition or other extenuating circumstances dictated otherwise.

The periodic program reviews through EPRI also continued and both portions of the program began to see improved ratings. Work requests were being issued through the team meetings and Station training was also implemented through EPRI with specific links to boiler reliability. As an example, EPRI was brought in to review and hold training courses on the mechanism of long term overheat and how minimal temperature excursions or slight temperature increases could contribute to this mechanism and future tube failures.

7.0) CURRENT PROGRAM STATUS

The Station's final scheduled review was held in March of 2004. The final rating for the boiler portion of the program had improved to the very good status and the cycle chemistry portion of the program had improved to the good status. At the end of 2003, the BTF percentage was at 1.46. Into early 2004, the BTF percentage had risen slightly due to a couple of new mechanisms that had caused down time. At the time of the final review, the rolling twelve month BTF percentage was at 1.85.

Since the final review, the team still meets on a monthly basis excluding scheduled outage months. Topics for the meeting continue to include any prior tube leaks, the action item status, and a chapter summary discussion. The active mechanisms that have been identified for each unit continue to aid the team in the planning of both temporary and permanent repair strategies. Through August of 2004, the Station's BTF percentage was at 1.93. The team's annual goal had been less than two percent based on the existing active mechanisms in each of the Station's boilers.

Also, with the team's efforts, the program has moved away from the more reactive style, but has not yet moved into a completely proactive style of program. The team has made changes in both outage planning and repair methods to aid in being more proactive. However, the team also realizes there is more to do to complete this change.

8.0) FUTURE PROGRAM

To further the impacts on Station reliability, the team plans to continue the monthly meetings with similar agenda items for discussion. Utilization of the team members thinking in developing repair and replacements is also planned. The team also realizes that several sections of the boilers are at or nearing their end of life. To improve upon and maintain the existing BTF percentages, the long range plans that have been developed will need to be implemented. The temporary repairs completed thus far have helped to reduce the number of failures. However, a great deal of the known damaged tubing still exists in the operating units.

9.0) CONCLUSION

To summarize, the development of a boiler tube failure reduction program at the Merom Station was a significant contributor to the reduction in the number of tube failures. The program, in conjunction with the knowledge and planning skills of existing Station personnel, has helped to reduce the BTF percentage by over three percent in the past three years. In addition, team members have improved their level of knowledge on boiler tube failure mechanisms and susceptible locations. Implementation of the program has also generated changes in the operating and repair procedures to further improve overall boiler and Station reliability.

Implementation of a Boiler Tube Failure Reduction Program at Progress Energy

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1 ABSTRACT

Several utilities have used the EPRI BTFR program as a model to implement such a program at their utility. This paper illustrates key components of the program implemented at Progress Energy. One of the most important components was to develop a corporate guideline to comprehensively address all the elements needed for a BTFR program and to define team and organizational responsibilities. Another component was the development of a software application for tracking, resolving, and analyzing tube failures system-wide. Reporting tools developed to provide management with key performance information are also illustrated.

2 BACKGROUND

The BTFR program was initiated at Progress Energy in 2000 (then known as CP&L). This was fairly late compared to other utilities, some of which started in 1986 at the EPRI program's inception. Availability losses for the 22 Progress Energy pulverized coal boilers due to BTF were around 2% and had not been cause for concern by previous management. As the industry continued to change and our company looked for ways to improve, corporate management decided to initiate a formalized BTFR program. In 2001 Florida Power merged with CP&L to create Progress Energy and added four coal and eight oil fired boilers, bringing the total to 34 boilers in our system.

Several elements of a BTFR program were in place, but there was no comprehensive management of these activities. Progress Energy already had a separate chemistry program manager and a welding program manager. We also had our own NDE services, like many utilities, but unlike many utilities, had the advantage of a full scale metallurgy lab internal to Progress Energy. There was also an active internal program for conducting the remaining life analysis of high temperature boiler tubes.

3 PROGRAM DESCRIPTION

3.1 Team Organization

In order to implement this program, an interdepartmental, multidisciplinary matrix organization of expert personnel from the central, regional, and plant levels is used. On the corporate team are the BTFR program manager (experienced boiler engineer), chemistry program manager, NDE services supervisor, welding program manager, metallurgist, and six regional boiler engineers. (Figure 1) This team is widely dispersed, since it represents personnel from three

departments including one member from Nuclear. Progress Energy's BTFR program manager was originally not a full time position. Until it became a full-time position in 2002, progress was often hampered due to other project and outage responsibilities.

Originally, the regional boiler engineers were stationed at the plants and part of the plant teams. They became part of the corporate team when engineers were moved from the plants to three regions that were created in a 2002 reorganization. Currently they serve double duty as members of both the plant and corporate teams.

The plant teams were originally set up with the plant engineers as the team leads. Generally speaking, the plant teams have representation from management, maintenance, operation, and the chemistry lab. The teams fluctuate due to turn over and have been inconsistently formed across the system. One shortcoming noticed has been the lack of operator involvement at some facilities.

3.2 Training

Initial training in BTF fundamentals, using EPRI resources, for personnel from most of our generating stations, was conducted in 2000. After the merger with Florida Power, an additional round of training was conducted at these sites in 2002. Based on feed-back from the plants, additional (re)training specifically for the Maintenance and Operations personnel was conducted in 2003 by the BTFR and chemistry program managers. Keeping up with training is recognized as an ongoing process. We are developing a computer-based training module to allow new personnel to learn about BTFR/CCI fundamentals or experienced personnel to review it. This will free up some time from the program managers but is not expected to entirely replace all hands-on training.

3.3 BTFR Guidelines

As with most utilities, the first course of action in setting up a BTFR program was to develop a corporate directive and policy statement and have it signed by department management. Although this defined the basic requirements and goals of the program, the implementation was inconsistent across the system.

The BTFR guidelines[2] were developed to clarify roles and responsibilities as well as lay out in one document all of the needed elements to implement a BTFR program at a generating station. This document is posted on the company intranet, along with other controlled engineering documents, for access across our system. This served as a reference for each plant team to modify for specific unit conditions and to incorporate into their own procedures and work practices. This has been completed at most sites.

One key to defining the process is to develop a decision criteria for the plants that is flexible enough to take into account various constraints placed on the plants by the competing requirements of dispatch, cost, power sales and environmental restrictions. For this purpose, a System Condition Criteria, as shown in Figure 2, was developed to guide operation and maintenance decisions. This is broken into three categories: Economic, Reliability, and Environmental. For each of these categories, three states exist: red, yellow, or green. Break points for these states may vary from station to station.

The roles and responsibilities are spelled out for four functional organizations: engineering, operations, maintenance, and management. The engineering / technical support group consists of those functions which directly support the program. Responsibilities for providing support for welding (repair), NDE, chemistry, and metallurgy (mechanism verification and failure analysis) are defined here. The regional boiler engineers provide more direct guidance to the plant, especially in areas of mechanism identification, root cause analysis, remaining life analysis, and developing action plans.

Operations guidelines state that; "Operating the boiler in all modes such as Startup and Shutdown, Continuous Operation, Load Following, or Lay-up in a tube damaging condition is discouraged unless system condition warrants otherwise". One area of concern has been operating with tube leaks. A decision table has been developed (Figure 4) using the system condition to guide the operators. This table is usually modified by the plants to fit the requirements of their individual units. Operations personnel are also responsible for monitoring critical parameters which can lead to activation of failure mechanisms such as temperature limits (Figure 3) and chemistry limits. They are also aware of and monitor unusual combustion problems (e.g. slagging or high ash) that can lead to tube failures if left uncorrected.

Maintenance guidelines define what actions should be taken during forced or scheduled outages. Two key items are the repair standards and the forced outage plan (FOP). Repair standards specifically define when a padweld is allowed using a decision table (Figure 6) based again on system condition and whether or not the failure mechanism is a high risk failure mechanism. The other key element of the maintenance responsibility is using a FOP checklist (Figure 5) to ensure all the steps of the BTF process are completed. Some steps can be omitted, as shown, in order to save time during an outage, if warranted, based on the system conditions.

Management responsibilities are relatively limited compared to the other functional groups, but no less important. This boils down to providing the top down support for resources, creating incentives, and defining accountabilities for the responsible personnel.

3.4 Information Management - The Boiler Tube Failure Assistant, BTFA

One necessary component of any program is to have some means of tracking the failures and storing all the information related to a failure event. Several commercially available software packages were evaluated, but it was decided to develop an in-house application using Microsoft Access. The advantage to this was to have something easily customizable for a small investment of time. The main advantage to this strategy has been to form a central location from which to look up information and to link to a variety of documents and databases, as needed.

The main application, called the Boiler Tube Failure Assistant or BTFA, is a database of the failure events. Detailed information for each event is recorded in over 100 available fields. This is divided into 6 general groups. The first group, **General Information**, contains fields for plant identification, date and time off and on line, lost MW, outage type, etc. Additional fields are available to enter operating conditions (e.g. temperature, pressure, pH) near or at the time of the failure, if they are known. The next group is **Failure Location,** which describes in detail where the failure occurred (assy., row, elev., etc.)**.** Included here is a link to a sketch (in PowerPoint) of

where the failure is located. The third group is **Failure Description**, where the appearance of the failure is described. This is where links to photos of the failure are placed as well. Next is a page for **Failure Mechanism / Root Cause** where additional mechanisms and causes can be listed and plans for verification and short-term corrective actions described**.** A fifth page is for documenting **Repairs,** which includes help on selecting weld procedure specifications. There is also a link to a spreadsheet to calculate min wall and simple remaining life due to erosion (wall loss) or creep. The last page, **Post Outage Analysis**, is where long term action plans are described and external reports are linked to the event, such as metallurgical reports, NDE reports, and root cause analyses.

The BTFA has been expanded to store other data as well. One part is used for generating the expected or predicted tube failures in future years. This is used primarily in goal setting and assessing the risk due to tube failures. There is also a database where historical information can be stored about the boiler. This can include such things as when chemical cleanings were performed or when repairs were made to a bank of tubes. A large part of the application is devoted to analyzing the data and producing reports. Several reports have been devised to present the impact of BTF. Some examples are failures grouped by plant, component, year, or mechanism. Other reports present data as rolling monthly averages (Figure 7 or Figure 8) or can rank mechanisms by EAL (Figure 10).

4 RESULTS OF THE BTFR PROGRAM

There are several metrics that can be used to measure BTF performance at the plants. Four statistics compiled are number of failures, megawatt-hours (Mwh) lost, equivalent availability loss (EAL), and lost generation cost. Of these, the number of tube failures is important in showing how many failures are found, and EAL is important in showing the impact to the system. If costs can be calculated based on hourly market value of power, then the cost can show the importance of the timing of outages. This is especially useful information prior to the plant coming off-line, as shown in the discussion of system condition.

The use of rolling 12 month averages shows the trend in the number of failures in Figure 7 and EAL in Figure 8. Both have been generally downward, but this year EAL has hit a plateau and may be moving back up due to several failures at some of the larger generating stations. Other reasons for this plateau are listed with the challenges facing the program below.

An important reporting tool developed in the BTFA was the ability to group the failures in a number of ways. BTF's grouped by failure mechanism and ranked by their impact (EAL) to the system is shown in Figure 10. For Progress Energy, the predominant mechanisms are fly-ash erosion, long term overheating, fatigue (thermal and mechanical), and dissimilar metal weld (DMW) failures. The latter is due to mostly one unit where the DMW's reached end of life before they were predicted. Curiously absent from the top 10 list is corrosion fatigue. This is contrary to EPRI's statistics for the industry and may be due to lack of proper identification of mechanism due to lack of access or sampling at the plants. This report shows that 97% of Progress Energy's losses are due to the top 10 failure mechanisms. It also shows the contribution of chemistry-related failures is 8%. Another report breaks down failures by generating station, unit, component (tube circuit), and mechanism and ranks them by EAL.

Repeat failures are reported here as well. This has been useful in identifying and prioritizing problem areas for specific units.

At the corporate level, as well as at the plants, the program has continued to improve in most cases, as shown by the benchmark scores in Figure 9 from the EPRI progress reviews. Several facilities scored near or at world class. This was primarily due to having good runs in the last 12 months resulting in low EAL and to adopting the program guidelines as a plant document. Some plants saw their benchmark scores increase due to their EAL increasing. The benchmarks show that we have all the elements in place to do a world class job of controlling tube failures. However, we feel that the benchmark process is optimistic and does not go into enough depth to track how well the plant adheres to the process. In the future, we plan to track the performance of the individual requirements set down in the guidelines in much greater detail.

5 FUTURE DIRECTION

Based on recent reviews by EPRI and our own internal program assessments, we have identified several areas to focus improvements. The most significant is how to move the program to a more proactive process rather than reactive. This is a natural evolution, as the first order of business is to understand and correct problems resulting in tube failures. The essence of this philosophy is to prevent repeat failures. Once the program has developed to the point that problems are accurately tracked, analyzed, and corrected, one needs a rigorous implementation of the process defined in column C of figure 1-1 from BTF theory and Practice[1] shown in Figure 11 to become more proactive.

Training and retraining remain as issues because of continuing turn over. More detailed training on failure mechanism and how the actions of various organizations can activate them is being considered. Some of the retraining is being migrated to a computer-based system to allow flexibility for those taking it and less dependence on instructors.

Communications between functional groups continues to be a challenge especially at the plant level. Removal of engineering from the plants to regional offices complicated collaboration on identification and correction of boiler tube failures. Most plant organizations are organized along maintenance and operations functions. Through training of personnel and meetings with management, the importance of breaking down the barriers was emphasized. We will be involving the operations personnel more in the future as we migrate toward a proactive program.

Achieving a world class BTFR program (EPRI definition) will require EAL to be less than .5% with no repeat failures. Few utilities approach these numbers with ESKOM often cited as being closest. Many reasons to lower EAL exist. Goals for system effective forced outage rate (EFOR) have steadily been driven downward and NOx season reliability of large units has become very important. At the same time, there are many challenges. Budgets remain flat or are reduced. Outage durations are reduced and spaced further apart leaving less time to do preventative maintenance. There is increased pressure to use less expensive fuels which are usually lower in BTU and higher in ash.

6 CONCLUSIONS

The BTFR program at Progress Energy has been effective in reducing losses due to BTF. Justification for repairs and replacements has been made easier, more consistent, and thorough by utilizing the information from the BTFA database. The reports generated from the BTFA provide better direction on how to prioritize corrective actions. Work remains to be done, but given the support and visibility BTF has, Progress Energy will continue toward world class BTF performance.

7 REFERENCES

1. Dooley, B., McNaughton, W., "Boiler Tube Failures: Theory and Practice, EPRI, Palo Alto, CA: 1996. Report TR-105261.
2. "Boiler Tube Failure Reduction Program Guidelines", Progress Energy Controlled Document, EGR-POGX-00082,

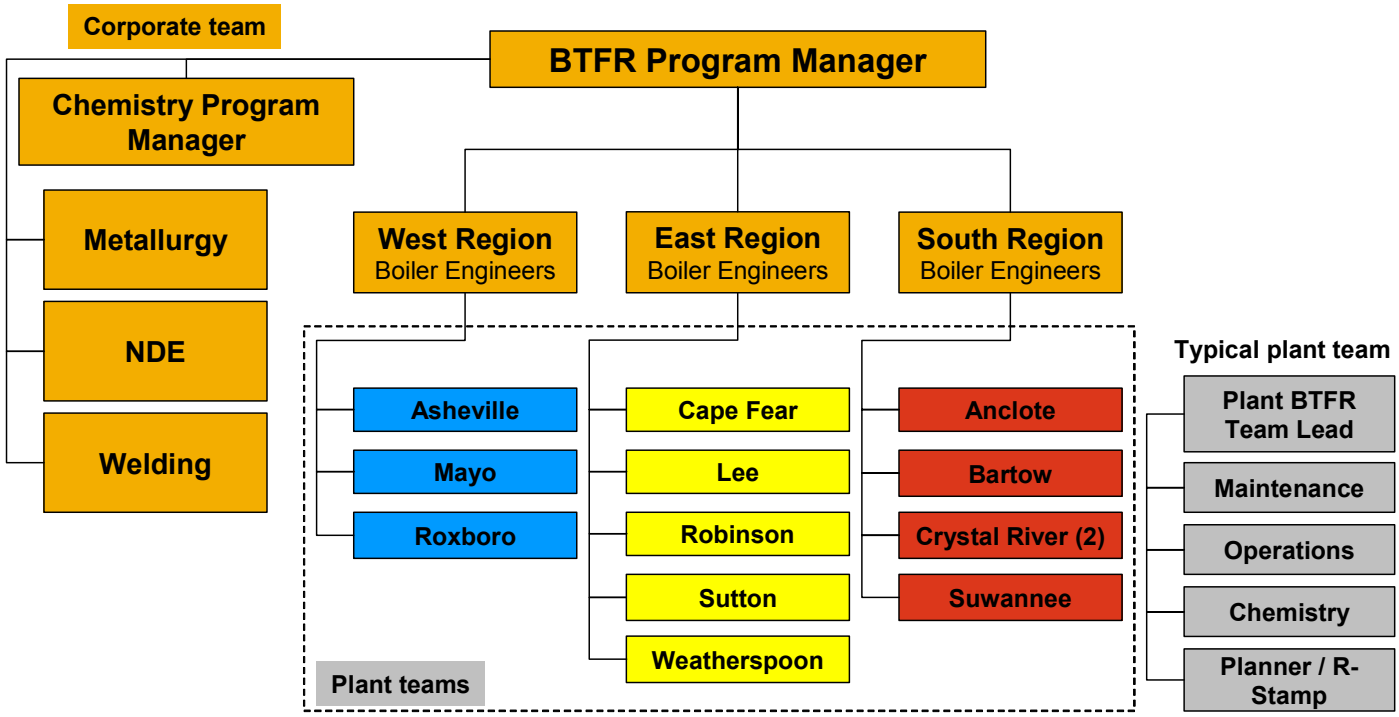


Figure 1, Matrix Organization of BTF Teams

System Condition Criteria

	Green	Yellow	Red
Economic	System Clearing Cost <$20/Mwhr	System Clearing Cost $20-$50/Mwhr	System Clearing Cost >$50/Mwhr
Reliability	System Normal, Level 0	System Reliability Alert, Level 1	Capacity Curtailment, Voltage Reduction, Level 2 or above
Environmental	All emission goals on target	Projected emission goals may not be met	Currently projected to exceed emissions goal

Figure 2, System Condition

Temperature Limits

		System Condition		
		Green	Yellow	Red
SH/RH tubes	Low alarm	Reduce in 2 hours	Reduce in 24 hrs	Reduce in 36 hrs
	High alarm	Reduce in 2 hours	Reduce in 8 hours	Reduce in 24 hrs
	>1100	Reduce ASAP within 2 hrs	Reduce in 4 hours	Reduce in 8 hours
Bulk SH/RH	>1010	Reduce ASAP within 2 hrs	Reduce in 8 hours	Reduce in 24 hrs

The decision to operate at elevated temperatures should also consider the general condition and failure history of the component. Creep damage is a highly non-linear function of temperature. Total operating time exceeding alarm temperatures should be no more than 168 hours (7days) in a 12 month period. Always consult Engineering

Figure 3, Temperature Limit Decision Table

		System Condition		
Leak Location	Leak Severity	**Green**	**Yellow**	**Red**
SH	**Minor**	Can delay up to 8 hours	Can delay up to 16 hours	Delay no more than 7 days
RH	**Minor**	Can delay up to 8 hours	Can delay up to 48 hours	Delay no more than 7 days
Economizer	**Minor**	Can delay up to 24 hours	Delay no more than 7 days	Delay no more than 7 days
Waterwall	**Minor**	Delay no more than 7 days	Delay no more than 14 days	Delay no more than 14 days
SH	**Moderate**	Can delay up to 8 hours	Can delay up to 16 hours	Delay no more than 7 days
RH	**Moderate**	Can delay up to 8 hours	Can delay up to 48 hours	Delay no more than 7 days
Economizer	**Moderate**	Can delay up to 24 hours	Delay no more than 7 days	Delay no more than 7 days
Waterwall	**Moderate**	Delay no more than 7 days	Delay no more than 7 days	Delay no more than 7 days
SH	**Major**	Notify ECC to shutdown within 2 hrs	Notify ECC to shutdown within 2 hrs	Can delay up to 8 hours
RH	**Major**	Notify ECC to shutdown within 2 hrs	Can delay up to 8 hours	Can delay up to 8 hours
Economizer	**Major**	Notify ECC to shutdown within 2 hrs	Can delay up to 4 hours	Can delay up to 8 hours
Waterwall	**Major- Interior**	Can delay up to 48 hours	Can delay up to 72 hours	Can delay up to 72 hours
Waterwall	**Major- Exterior**	Notify ECC to shutdown within 2 hrs	Can delay up to 12 hours	Can delay up to 24 hours

Minor	No noticiable increase in makeup water
Moderate	Detectable increase in makeup water, < 1"/hr
Major	Increase in make up water >1"/hr above normal

If the condition is posing a personnel hazard or flame stability issue the unit needs to be brought off-line regardless of system condition.

The time any component runs with a leak is determined by the amount of collateral damage that can be done due to downstream overheating or steam washing. Repair time should also factor in how accessible the failed tube is. Both are a function of tube spacing.

Figure 4, Run With Leak Decision Table

BTF Forced Outage Plan Checklist

System Condition			
Green	Yellow	Red	
			1 Pre-Repair Inspection
			1.1 Identify Location of Primary Failure
			1.2 Identify Primary Failure Mechanism
			1.3 Develop Possible Root Causes
			1.4 Identify Most Probable Root Cause
			1.5 Determine Extent of Damaged Tube
			1.6 Determine Extent of Collateral Damage (wash, etc.)
	X	X	1.7 Determine sample locations for mechanism and root cause verification
	Take the following to perform pre-repair inspection: Blank event form, blank sketch of component, digital camera, ultrasonic thickness meter (if needed). Use the BTF theory and practice manual and BTFA software to help determine failure mechanism and root cause.		
			2 Develop Repair Instructions
			2.1 Repair primary failure and collateral (secondary) damage
	X	X	2.2 Remove and replace samples and send to Metallurgy lab
			2.3 Complete documentation for compliance with Welding (R-Stamp) Program
	Complete Weld Repair Instruction Form. Completed R-1 package should be on file within 2 weeks of end of outage. We are legally required for code boilers to submit paperwork within 60 days.		
		X	**3 Identify Other Areas Susceptible to Same Mechanism and Root Cause**
		X	3.1 Inspect other areas susceptible to same mechanism and root cause
		X	3.2 Identify tubing damage
		X	3.3 Determine remaining life and Develop repair instructions.
	X	X	**4 Determine Remaining Life of Damaged Tubing**
	X	X	4.1 Review previous boiler inspection data
	X	X	4.2 Determine NDE requirements
	X	X	4.3 Determine number and location of samples (if necessary)
	Regional Engineering or Engineering Programs will assist with this item as needed.		
	X	X	**5 Inspect Boiler For Other Potential Tube Failures**
	X	X	5.1 Perform limited inspection of other areas of Boiler
	X	X	5.2 Identify tubing damage, mechanism & root cause
	X	X	5.3 Determine remaining life and Develop repair instructions.
	Refer to unit specific standing inspection orders for problem areas.		
			6 Complete Documentation
			6.1 Complete BTF report in database
			6.2 Develop action plan to correct/prevent recurrence of root cause
			6.3 Develop action plan for replacement and/or upgrade of damaged tubing
	Preliminary data (pre repair checklist data from item 1) should be entered as soon as possible but no more than 72 hours after discovery of failure to facilitate communications. The failure event record should be completed within 10 days of the completion of the outage. This excludes attached documents such as NDE or metallurgy reports or editorial changes as new information becomes available.		

Note: Items on this checklist are primarily within the scope of Maintenance but resources from Operations, Regional Engineering and Engineering Programs should be utilized as needed.

Figure 5, Forced Outage Plan

	System Condition		
	Green	**Yellow**	**Red**
Low Risk Mechanism	Replace	Padweld if replacment increases time > 8 hr	Padweld, replace later
High Risk Mechanism	Replace	Replace	Padweld, replace later

In all cases R-stamp procedures must be adhered to including all NDE requirements to ensure all damaged tubing is repaired. See also BTFR guidelines section 9.2

Low Risk Mechanism	**NDE**	**High Risk Mechanism**	**NDE**
Caustic Gouging	RVT	Corrosion, Flow Assisted (Erosion-corrosion)	UT, VT, RVT
Chemical Cleaning Damage	UT, RVT, RT	Corrosion, SH/RH Fireside (Coal)	UT, VT
Corrosion, Acid Dewpoint (Low Temperature)	UT, VT	Corrosion, SH/RH Fireside (Oil)	UT, VT
Corrosion, Acid Phosphate	UT, RVT	Corrosion, Stress Assisted	UT, FATS
Corrosion, biological (MIC)	UT, EC	Creep - Fatigue	UT, MT, WFMT
Corrosion, Crevice	VT	Creep, Long Term Overheating	UT, VT
Corrosion, Galvanic	VT	Creep, Short Term Overheating	VT
Corrosion, Pitting	UT, EMAT	Dissimilar Metal Weld Failures	UT, MT, WFMT, FATS
Corrosion, WW Fireside (Coal)	VT, UT	Fatigue, Corrosion	FATS, EMATS
Erosion, Coal Particle	UT	Fatigue, Thermal	UT, VT
Erosion, Flyash	UT	Graphitization	
Erosion, Other	UT	Hydrogen Damage	EMAT
Erosion, Rubbing / Fretting	UT	Low-Temp. Creep cracking	FATS, EMATS
Erosion, Sootblower	UT	Stress Corrosion Cracking (SCC)	FATS, EMATS
Erosion, Steam	UT	Supercritical Waterwall Cracking	VT, UT
Falling Slag Damage	VT, UT		
Fatigue, Mechanical	UT, MT, WFMT		
Maintenance Damage	VT		
Material Flaws	RT, UT, VT, RVT		
Mechanical Damage	VT		
Rolled Tube Leak	RVT, VT		
Welding / Repair Defects	RT, UT, VT, RVT		

NDE Methods

EC, Eddy Current	VT, Visual Test
MT, Magnetic Particle, Dry	RVT, Remote Visual Test (video probe)
WFMT, Wet Flourecent Magnetic Particle	UT, Ultrasonic testing
RT, Radiographic Testing	EMAT, Electomagnetic Acoustic Coupled Test
LPT, Liquid Penetrant Testing	FATS, focused array test system

Figure 6, Repair Decision Table

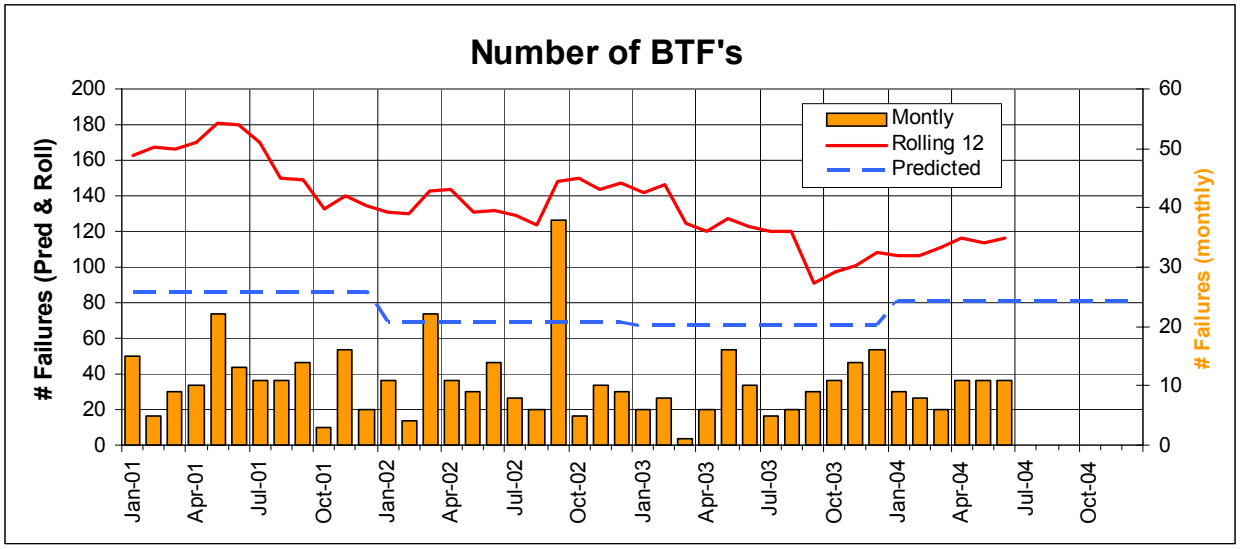


Figure 7, Number of BTFs over last 4 years

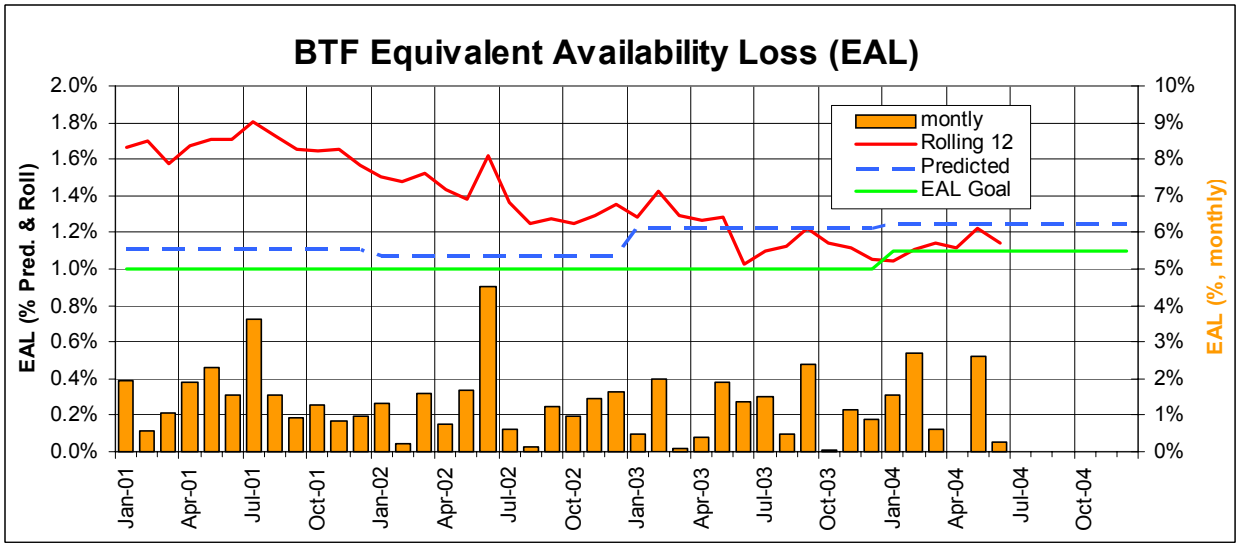
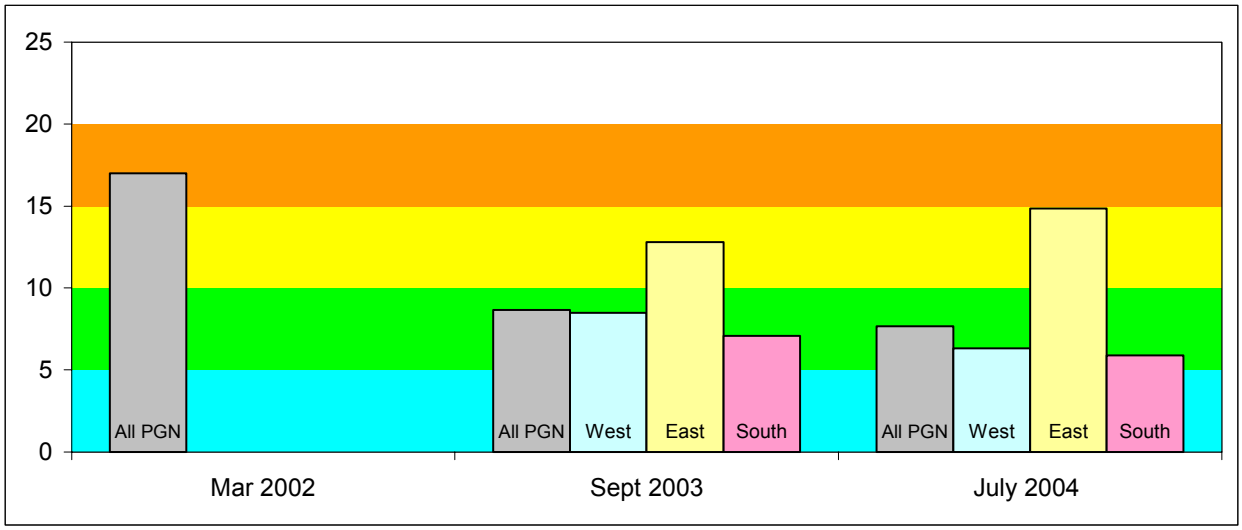


Figure 8, BTF Availability Loss Over Last 4 Years



	Mar 2002	Sept 2003	July 2004
All PGN	**17**	**8.7**	**7.7**
West		**8.5**	**6.3**
East		**12.8**	**14.8**
South		**7.1**	**5.9**

BTFR Program Rating System

World Class	Very Good	Good	Average	Below Average
0-5	**6-10**	**11-15**	**16-20**	**>20**

Figure 9, EPRI Program Benchmark Scores

From 6/1/2003 to 6/30/2004 For All Fossil Steam Plants

Mechanism	# Failed	Lost Mwh	Unit EAL	Cost (K$)
Erosion, Flyash	27	252,355	0.31%	$6,326
Creep, Long Term Overheating	19	234,726	0.29%	$5,213
Fatigue, Thermal	31	139,767	0.17%	$3,225
Dissimilar Metal Weld Failures	10	128,455	0.16%	$2,861
Fatigue, Mechanical	12	81,628	0.10%	$1,861
Low-Temp. Creep cracking	1	64,812	0.08%	$1,408
Corrosion, Pitting	4	56,559	0.07%	$1,279
Maintenance Damage	1	30,960	0.04%	$678
Creep, Short Term Overheating	1	30,625	0.04%	$865
Welding / Repair Defects	4	23,573	0.03%	$596
All Other	22	32,178	0.04%	$653
Total	**132**	**1,075,638**	**1.32%**	**$24,965**
Top Ten	**110**	**1,043,460**	**1.28%**	**$24,312**
% top ten	83%	97%		
Chemistry Influenced	**21**	**87,512**	**0.11%**	**$1,907**
% chemistry	16%	8%		

Figure 10, BTF Mechanisms Ranked by EAL

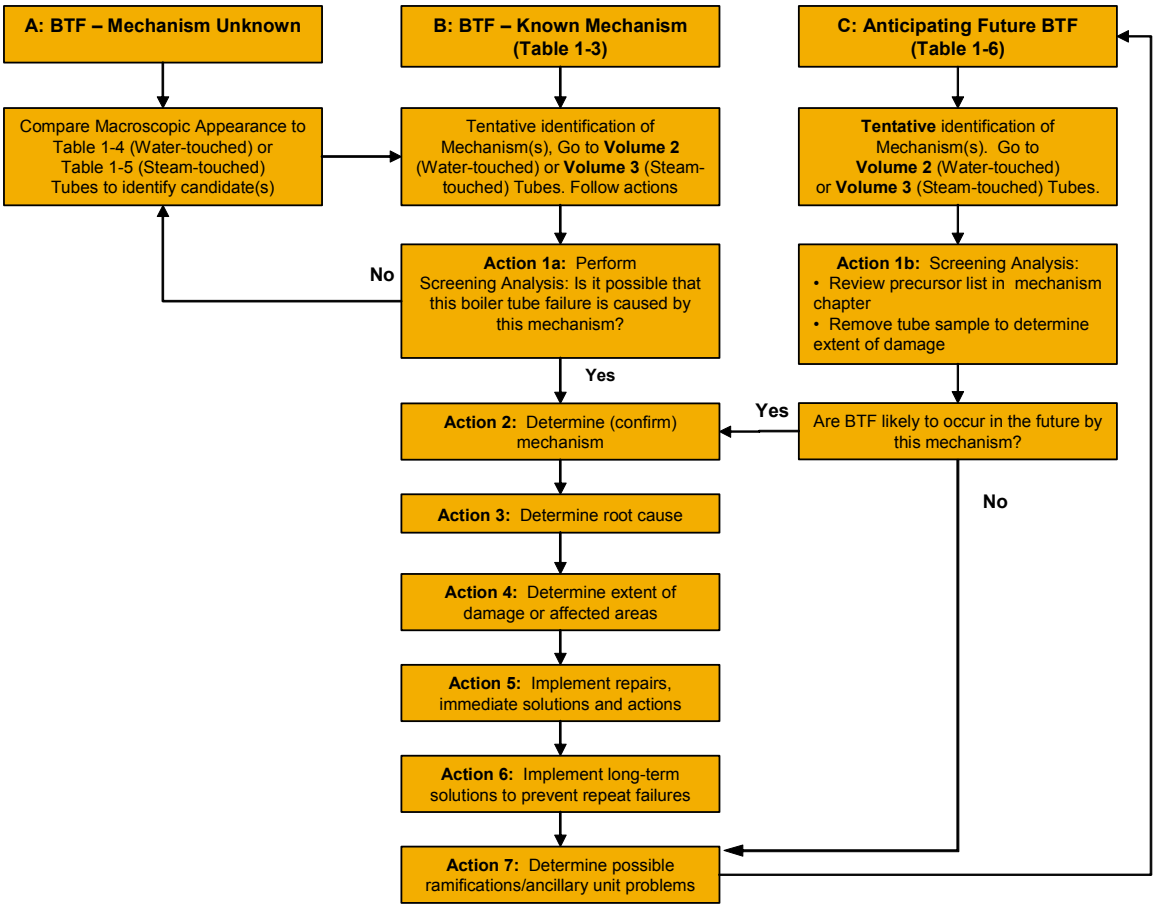


Figure 11, BTFR Process Flowchart

The Necessary Steps to Obtain a "World Class" Boiler
Availability Status

Steve Richter
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The Great River Energy, Coal Creek Station achieved a "world class" boiler availability status in 2003. This "world class" status is an Electric Power Research Institute, EPRI, standard that requires a station Equivalent Availability Loss, EAL, due to boiler tube failures of less than one percent for an entire year. Coal Creek Station achieved a .95 percent Equivalent Availability Loss in 2003.

I will be sharing the **four** key steps Great River Energy, Coal Creek Station believes are necessary to obtain this difficult "world class" operating status.

The **first** and foremost step in obtaining a "world class" boiler availability status is to have a REASON to do it! Our company has approximately 2,500 MW's of available generation. The two Coal Creek Station units are each 600 MW units. Any time one of these units is down for an emergency tube failure repair, 25% of our available generation is out of service and must be replaced by energy on the open market. This replacement energy has been steadily increasing over the past several years and depending on regional conditions can be very costly to the organization. Coal Creek Station had a reason to take actions to reduce our boiler tube failure numbers.

The Coal Creek Station average boiler tube failure rate from 1993 to 2004 was 9.6 total failures per year for both units. See table.

Year	CCS, Unit 1	CCS, Unit 2	CCS Totals
1993	2	2	4
1994	6	6	12
1995	4	4	8
1996	3	0	3
1997	8	4	12
1998	9	9	18
1999	6	2	8
2000	4	9	13
2001	5	6	11
2002	11	1	12
2003	2	2	4
2004	4	4	8
TOTAL	**64**	**49**	**113**

The cost of energy has also been on a steady increase in our region. See table.

Year	Hours off-line	Cost per MWH	Total cost
2000	373	$29.70	$5,127,594
2001	227	$19.83	$1,807,710
2002	336	$20.94	$2,724,237
2003	167	$29.36	$2,077,562
2004 to date	213	$37.44	$3,827,343

The **second** step in obtaining a "world class" boiler availability status is to be willing to INVEST in both human and material assets. The past process of boiler maintenance management was not meeting our goal and objective of being a reliable, competitively priced energy provider.

The Boiler core area and Engineering services were asked to evaluate this boiler reliability problem in 1999 and recommend possible solutions. The team decided that our first task was to evaluate the current boiler maintenance program and determine what actions could be taken to improve this program.

It did not take long to realize in the evaluation process that one of the most obvious improvements was to get more people involved in the boiler inspections during major outages. The accepted process was to have one Boiler System Engineer manage the entire boiler inspection and repair process with assistance from the corporate office engineering staff. Although this corporate office engineering staff was helpful in the inspection process, ownership in specific boiler areas and redundant inspection personnel who were familiar with the Coal Creek Station boiler inspection procedures was impossible to obtain.

A decision was then made to get more Coal Creek Station employees involved with this boiler inspection process. These people had to be chosen from the current workforce and needed to be trained on boiler inspection techniques and boiler tube failure analysis. Both Alstom Power Integrated C-E Services, Inc. and Electric Power Research Institute, Inc. were utilized for this boiler inspection and boiler tube failure analysis training.

Thirty-nine employees completed EPRI's Integrated Boiler Tube Failure Reduction, Cycle Chemistry Improvement Program training in 2000. Nine additional employees completed this training in 2002. Fourteen employees completed the Alstom Power Utility Boiler Inspection training in 2001.

After this training was accomplished these additional Coal Creek Station employees were available to perform a more thorough physical boiler inspection and boiler life assessment. This would however, require an increase in the boiler outage budget due to the increased human resources involved with these inspections. Additional costs were also likely for material needs, most of which would be for boiler tube replacement. Coal Creek Station did realize both a

reduction in hours off line and total cost of replacement power in 2003. So the belief is this maintenance budget increase will actually result in a continued reduction in the total cost of operation in the future due to these replacement power savings.

The goal of being a reliable, competitively priced energy supplier requires our generation sources to be available. And although the number of hours Coal Creek Station has been off-line due to boiler tube failures has been on a decline, the cost of purchased replacement power has been on the incline. This increased power cost justifies the additional boiler outage budget costs. See table.

Year	Hours Off-Line Due to Tube Failures	Replacement Power Costs	Boiler Outage Maintenance Budget
1999			$1,079,500
2000	373	$5,127,594	
2001	227	$1,807,710	$2,443,000
2002	336	$2,724,237	$3,547,500
2003	167	$2,077,562	
2004	213	$3,827,343	$3,702,300

The **third** step in obtaining a “world class” boiler availability status is to determine a SYSTEM to accomplish this goal. It was commonly understood that the boiler equipment was getting older and the chances of increased boiler tube failures was a real possibility. What was needed then was some type of systematic approach to improve the reliability of this aging equipment.

A determination was made previously that one engineer could not possibly inspect and direct repair activities for a boiler that has 1,175,000 linear feet of boiler tubing. So a review of the major boiler structure was completed and a decision made to divide it into five distinct areas. These five areas consist of the Burner front area, Water wall area, Superheat and reheat pendant area, Back-pass area, and External area.

The next hurtle was to determine where to find the human resources available to assign to these five areas. Great River Energy was in a no-hire directive, as were most utilities at the time. So it was obvious that current Coal Creek Station employees would need to be re-assigned to fill these new critical areas of responsibility. The decision was made to assign two system engineers, two certified welders, and a past certified welder currently assigned as a construction project coordinator to these areas. One of the five employees selected normally reports to the Leader in the Boiler core on a regular basis, the other four employees report to this leader only during major outages.

This five employee boiler outage team was called the Boiler Area Owner – Inspection Team. The ownership was assigned as follows:

System engineer – Burner front area
System engineer – Water wall area
Construction project coordinator – Superheat and reheat pendant area
Certified welder in the Fuel core – Back-pass area which includes furnace screen tubes through economizer section
Certified welder in Boiler core – External boiler area which includes all drums, dead air spaces, hangers and structural support

Also, during this evaluation process, boiler maintenance improvement ideas were being pursued from Alstom Power Integrated C-E Services, Inc. and Electric Power Research Institute, Inc. for a more detailed systematic approach.

The **fourth** and final step in obtaining a “world class” boiler availability status is to have sufficient KNOWLEDGE within the organization on boiler tube failure prevention. This knowledge is required in the boiler operation and maintenance processes and in specific employee technical skills.

Forty eight employees attended the Electric Power Research Institute, Inc. Integrated Boiler Tube Failure Reduction, Cycle Chemistry Improvement Program training. This training provided information to Chemistry Laboratory, Engineering, Maintenance and Operational employees on controllable ACTIVITIES that influence boiler tube failure and cycle chemistry problems. This training was very helpful in providing a technical basis for analyzing and solving problems that contributed to boiler tube failures and cycle chemistry excursions.

This EPRI training also provided Management personnel with controllable DECISIONS that influence boiler tube failure and cycle chemistry problems. Significant changes were made after this training in the areas of boiler operation with known tube failures or with known cycle chemistry problems. Changes were also made to the boiler tube maintenance repair and inspection processes. Two process documents are attached at the end of this paper as addendums and are titled “Coal Creek Station Directive” and the “Coal Creek Station Guideline”

Fourteen employees also completed the Alstom Power Utility Boiler Inspection training. This training provided information to plant employees on internal boiler inspections, pressure part inspections and repair guidelines. The training was very helpful to the employees that participate in the boiler inspection and repair process because the training information was presented on the actual Combustion Engineering boilers located at Coal Creek Station.

After all of the training was completed, a management decision was made to adopt the EPRI Boiler Tube Failure Reduction, Cycle Chemistry Improvement program (BTFR/CCI) as our basic boiler reliability improvement process. Some small changes were made in this program that is site and equipment specific to meet the operating needs of the Coal Creek Station, Great River Energy system.

I would like to insert one employee personnel topic at this time. The topic of "individual employee sensitivity to change" needs to be discussed and plans designed before entering any process change of this magnitude. All the employees at Coal Creek Station felt they were doing a good job at maintaining our plant equipment, which obviously included the boilers. So after deciding to make significant changes to some internal processes, there was an urgent need to diligently communicate the change and the expected benefits to these employees. The employees most directly involved with the old process needed to be nurtured and convinced of the possible benefits the new process would provide. It is urgent to answer the question of "what's in it for me" as clearly and concisely as possible to these employees. Answering this question will reduce the time required for employee "buy-in" and cooperation within the new process.

The following is a summary of the Coal Creek Station Boiler Tube Failure Reduction (BTFR) Program structure. There are three teams. The BTFR Steering Team is responsible for over-seeing and managing the entire BTFR/CCI program. The BTFR Inspection team is responsible for physically inspecting the boiler, providing recommended corrective actions, planning the major outage boiler maintenance activities, determining parts requirements and directing maintenance repair activities during major outages. The BTFR Analysis team is responsible for analyzing all boiler tube failures, determining the failure mechanism and root causes and recommending corrective actions. The make-up of employees on each of these teams is listed below.

Boiler Tube Failure Reduction Steering Team

Plant Manager
Leader, Power Generation – (Manager of team)
Leader, Power Generation and Operations Support
Leader, Engineering Services
Leader, Boiler Core
Leader, Lab Services
Boiler System Engineer
System Engineer

Boiler Tube Failure Reduction Inspection Team

Leader, Boiler Core – (Manager of team and budget responsibility)
Boiler System engineer – Burner front area & other area consultant
System engineer – Water wall area
Construction project coordinator – Superheat and reheat pendant area
Certified welder – Back-pass area which includes furnace screen tubes through economizer section
Certified welder – External boiler area which includes all drums, dead air spaces, hangers and structural support

Boiler Tube Failure Reduction Analysis Team

Leader, Boiler Core – (Manager of team)
Boiler System engineer
Certified welder
Certified welder
Chemical Analysis Technician
Construction project coordinator
Leader, Shift Team, Operations, on site at time of meeting
System engineer

In conclusion, I believe there are four key steps in obtaining a "world class" boiler availability status. If your organization is truly interested in reducing boiler tube failures, my recommendation is to use this proven methodology.

1. **R**eason to do it! If your company must always acquire replacement power which may be very costly during an emergency tube failure, I believe you have a REASON to want to reduce your boiler tube failures.

2. **I**nvest in assets! If your company has a reason to reduce your boiler tube failures, I believe they must be willing to INVEST in two specific areas. The first is in employee training in boiler operation, inspection and maintenance. The second is in actual boiler inspection and the replacement of necessary boiler parts.

3. **S**ystem to accomplish goal! If your company has a reason to reduce your boiler tube failures, I believe they must determine a SYSTEM to accomplish this goal. My recommendation is to adopt the EPRI Boiler Tube Failure Reduction, Cycle Chemistry Improvement program.

4. **K**nowledge about failure prevention! If your company has a reason to reduce your boiler tube failures, I believe they must acquire sufficient KNOWLEDGE about failure prevention in two specific areas. The first is in employee training on controllable activities that influence boiler tube failures. The second is in management training on controllable decisions that influence boiler tube failures.

In closing, I believe your company will need to take a ***RISK*** to obtain a "World Class" boiler availability status. The information shared in this presentation gives you some tools to do just that. But in all reality, the choice is YOURS!

Addendum #1

Coal Creek Station Directive
For
Great River Energy's Integrated Boiler Tube Failure Reduction / Cycle Chemistry Improvement (BTFR/CCI) Program

Purpose:
The purpose of this directive is to convey to all Coal Creek Station personnel our commitment to an integrated Boiler Tube Failure Reduction, Cycle Chemistry Improvement Program, which has as its objective, the planned correction, prevention and control of boiler tube failures and of cycle chemistry corrosion and deposition problems in our plant.

Background:
Boiler tube failures and possibly cycle-chemistry corrosion and deposition problems are the leading contributors to the unavailability of the Great River Energy / Coal Creek Station generating units.

Discussion:
According to the Electric Power Research Institute (EPRI), boiler tube failures and cycle chemistry corrosion and deposition problems are known to be industry worldwide problems. Using EPRI's Integrated BTFR/CCI Program as a model, GRE/CCS has elected to initiate its own formalized, comprehensive integrated Boiler Tube Failure Reduction/Cycle Chemistry Improvement (BTFR/CCI) program. The signing of the following BTFR/CCI Program Policy Statement indicates GRE's philosophy towards boiler tube failures and cycle chemistry corrosion and deposition problems.

Great River Energy's, Coal Creek Station, Boiler Tube Failure Reduction, Cycle Chemistry Improvement Program Policy Statement

Part 1 - Boiler Tube Failure Reduction (BTFR)
Every boiler tube failure will be reported and documented in a comprehensive format describing specific boiler and tube locations, failure mechanism, root cause and verification, type of repair, and future preventive and corrective action taken or recommended. (A boiler tube is considered to have a failure when its pressure boundary is broken by a leak or rupture, or prone to be broken due to further damage from the active failure mechanism before the next scheduled boiler inspection.)
Every boiler tube failure will be quantified in terms of failure mechanism, availability loss (%), cost (in $ and MWhr loss), and historical trend. A priority will then be established for immediate or planned corrective action.
Every boiler tube failure will require a pre-repair inspection to determine:
The failure mechanism - root cause*
The extent of damage to the failed tube*

The extent of damage to tubing in the close proximity of the failed tube*
The extent of damage to tubing in other boiler locations subject to the same failure mechanism and root-cause*
What sample specimens are appropriate for root cause failure analysis*
The extent of tubing damage or remaining life of same by using appropriate NDE and other life assessment technology*

*The only exception to not performing these activities during the forced outage is when in a “serious system condition.” A serious system condition is generally assumed to entail either a System Operations emergency condition or times of very high power market conditions (over $50/Mwhr).
Every boiler tube failure repair will be inspected and/or tested to verify tube pressure integrity before the repair is considered complete.

Every boiler tube failure repair will follow the quality assurance provisions of the North Dakota State Boiler Code Program for welder and inspector qualifications, welding materials, procedures, and selection of replacement tube material.

Every Boiler Tube Failure Report will be centrally processed for the purpose of: monitoring, trending, and control of individual plant, boiler and system performance; and communicating data/results specific to the needs of management, engineering, operations and maintenance personnel.

Every repeat boiler tube failure, i.e. multiple boiler tube failures that occur in the same boiler and same circuit due to the same failure mechanism and root cause, will require an Action Plan for preventing and/or eliminating any future boiler tube failures due to this failure mechanism and root cause.

All scheduled major boiler maintenance overhauls will include NDE inspections to determine remaining life of boiler tubing experiencing erosion, corrosion or long term creep damage. In areas experiencing damage, root cause analysis will be performed, and interim and/or long-term corrective / preventive actions or action plans taken to inhibit repeat forced outages due to these failure mechanisms.

All modes of boiler operation, such as startup, load increase/decrease and/or limit, planned or immediate removal from service and lay-up will be controlled by established steam/tube metal temperatures, and action-oriented operating procedures such that boiler tube damaging process conditions are minimized.

Continued boiler operation with known tube leaks is discouraged. It should only be considered when consequential damages are expected to be minimal and/or only when a serious system condition (as previously described) exists.

Use of temporary fireside erosion/corrosion tube protection methods, such as shields, plasma or metal spraying, is discouraged. Reduction of erosion or corrosion rates through correction of root causes or replacement with more resistant tube material (if necessary) is generally preferred.

Use of pad welding, weld overlays or window weld repairs is discouraged. They should be considered only for repair of low risk boiler tube failure mechanisms and/or only when a serious system condition (as previously described) exists. When used, they are considered as temporary and will be replaced at the next scheduled boiler maintenance outage or when practical.

Part 2 - Cycle Chemistry Improvement (CCI)

Every equipment corrosion and/or deposition problem will be defined, reported and quantified in terms of magnitude, historical trend and cost (MWhr, Btu/KWhr or dollar loss to the extent practicable), and a priority established for immediate or planned corrective action. (Generation equipment is considered to have a quantifiable corrosion and/or deposition problem when it can be quantified in terms of availability or performance loss.)

All units will be reviewed to determine and install the optimal cycle chemistry and instrumentation to satisfy the “core” cycle chemistry parameter monitoring and alarm requirements.

All core parameters relating to cycle chemistry, cation conductivity, sodium, pH and oxygen, will have established limits and be continuously monitored and alarmed in the control room.

All modes of unit operation (i.e., startup, load increase/decrease and/or limit, planned or immediate removal from service and lay-up) will be controlled by established unit-specific cycle chemistry limits, action levels and action-oriented procedures such that boiler or turbine damaging process conditions are minimized.

All Units will develop cycle chemistry technical and cost performance indices. The technical indices will track the % of time that “core” parameters for each unit are within limits for all modes of operation. The cost performance indices will track the plants direct and indirect cycle chemistry costs to the extent practicable; where the indirect costs are those associated with process equipment availability and/or performance losses due to corrosion and deposition problems.

All scheduled maintenance overhaul outages will include nondestructive testing and/or examination of areas experiencing either corrosion damage or excessive deposit buildup, such as turbine blades, condenser tubing on the cooling waterside, etc. In areas experiencing damage or excessive deposition, root cause analysis will be performed, and corrective, preventive and control actions will be taken to inhibit repeat forced outages due to these mechanisms.

Addendum # 2

Coal Creek Station Guideline
For
Immediate Plant Shutdown and Outage Considerations
Following Discovery of a Boiler Tube Failure

Purpose:
As a general rule, Coal Creek Station will not operate with known boiler tube failures. The intent of this document is to provide a set of guidelines that can be used in decision-making by shift operations personnel in determining upon discovery of a boiler tube failure whether controlled shutdown of the plant within two hours is warranted, or whether a repair outage involving the System Dispatcher, Power Marketers, and plant personnel can be scheduled.
This document also provides some direction on the length of outage and extent of repair/replacement work that should be performed based on power market conditions. These guidelines are intended to be just those --- guidelines. Particular circumstances, such as critical system conditions (see below), may warrant that the Shift Team Leader and Control Operator deviate from these guidelines.

Small Boiler Tube Failures:
A "small" boiler tube failure can be defined as a leak in which there has not been a noted increase in feed water makeup, and the leak has presumably been either visibly or audibly detected. In general, small tube leaks can be monitored on a regular basis for a worsening condition and scheduled for the coming weekend or a time period when inexpensive replacement power can be purchased. Should the leak be quickly deteriorating (as evidenced by feed water makeup or audible or visual indication), spraying outside the boiler, adversely affecting the fireball, or impinging on other tubes to the point where major collateral damage is likely, the plant usually can be rapidly shutdown in a controlled manner consistent with the Power Marketer's ability to line up additional power supplies.

It should be noted that small tube leaks within the superheat, reheat, or economizer tube bundles of the boiler have a high potential of causing collateral damage. Therefore, leaks in these sections should be treated as "major tube failures" (see below).

Major Tube Failures:
A "major" boiler tube failure can be viewed as a tube leak in which there has been a noticeable increase in feed water makeup rate. Imminent danger to personnel would be a cause for immediate shutdown. In general, an immediate, yet controlled plant shutdown should be started to avoid collateral damage to other tubes. The inability to visually locate a leak in the superheat, reheat, or economizer bundles would warrant an expeditious shutdown of the unit. However, there may be exceptions to immediately shutting down the plant in favor of shutting down in a controlled manner consistent with the Power Marketer's ability to line up additional power supplies. The exceptions are as follows:

1. The tube leak has been visually confirmed <u>not</u> to be impacting other tubes within the boiler and is judged not to be causing immediate additional damage (tube overheating, tube shear, personnel hazard, etc). If these conditions are met, the shutdown can be conducted in the time frame consistent for lining up additional power supplies.
   Note: Some monitoring of the superheat and reheat bundles can be performed by going to the Honeywell Main Graphics Menu and selecting the "Steam" automated graphs (however, not all tubes have thermocouple indication).
2. A critical system condition exists, i.e. either 1) the immediate cost of replacement power is greater than $75 per megawatt-hour, and it will take at least 4 hours to procure a cheaper source of replacement power, 2) the reliability of the electrical grid would be jeopardized by the immediate shutdown of the unit, or 3) the shutdown status of the opposite unit in wintertime could result in plant freeze-up without the auxiliary boiler being already in service.

Outage and Maintenance Response:
The length of a boiler tube failure repair outage will be dictated by the particular circumstances surrounding the leak and its repair. **All efforts should be made to limit the outage length to the time required to cool and clean the boiler, investigate for root cause failure, repair/replace the damaged tubes, and return the unit to service.** In general, other tube inspections and preventative maintenance should be conducted in parallel with the repairs by adding additional staff to perform the peripheral work. There may be circumstances, however, when it is prudent to extend an outage in order to conduct more extensive repairs that will prevent future unscheduled tube leak outages. The table below is intended to provide some guidance on when an outage extension or more detailed repairs may be warranted. Plant Management should be consulted when deviating from these guidelines.

	Power Market Conditions		
	Green	Yellow	*Red*
Replacement Power Costs	<$15/Mwhr	$15 – $35/Mwhr	>$35/Mwhr
Permissible Outage Extension for Maintenance	**Up to 16 hours**	Up to 6 hours	Up to 2 hours
Tube Failure Repair*	- High or Low Risk BTF Mechanism (Dutchman)	- High Risk BTF Mechanism (Dutchman) - Low Risk BTF (Pad Weld plus WO to remove)	- High or Low Risk BTF Mechanism (Pad Weld plus WO to remove)

*Note: See EPRI guidelines for definition of High or Low Risk Boiler Tube Failure Mechanisms

The following are some additional boiler tube inspection and maintenance criteria that will be used to help determine whether or not to replace or repair a tube or run until the next outage of sufficient duration:

1. A tube section replacement (Dutchman) is preferred on all tubes with less than 50% minimum wall thickness, a propagating crack, or one currently leaking.

2. Tube section replacement or pad welding is preferred on all tubes with between 50% and 65% minimum wall thickness. If pad welding is used, these tubes should be replaced at the next available opportunity.

3. Tube shield installation is preferred on all tubes with between 65% and 80% minimum wall thickness. These should be inspected at the next outage of sufficient duration.

4. No maintenance is required on tubes with between 80% and 100% minimum wall thickness. These tubes should be inspected at the next outage of sufficient duration.

A
CONFERENCE AGENDA

International Conference on Boiler Tube and HRSG Tube Failures and Inspections
November 2–5, 2004 | San Diego, California, USA

Tuesday, November 2, 2004

7:00 am	Continental breakfast and presenter/session chairperson breakfast
8:00 am	Welcome and introduction

PLENARY SESSION

	Chairman: R. Tilley, EPRI
8:15 am	Tube Failures in Conventional Fossil-Fired Boilers and in Combined Cycle/HRSGs **R.B. Dooley** and R. Tilley (EPRI)

SESSION 2: T91 Tube Issues

	Chairman: R. Tilley, EPRI
8:40 am	The Upgrading of Reheater Tube Panels in a Coal-Fired Boiler from T22 to T91 Tube Material – How Effective An Upgrade Is This Proving To Be? **T. Kirwan**, C. Gallagher, and S. Scully (ESB Power Generation, Ireland)
9:05 am	Evaluation of Long-Term Overheat Creep (LTO-C) Failures at AEP's Glen Lyn Plant **G. Guttner** (American Electric Power), K. Hara, C. Lee, R. Moser, S. Paterson (Aptech), and B. Dooley (EPRI)
9:30 am	Stress Corrosion Cracking in Grade 91 Left in the Fully Hardened Condition **J. Henry** and J.L. Arnold (Alstom Power)
9:55 am	Discussion on Session 2
10:00 am	**Break**

SESSION 3: Mechanisms #1 – Corrosion Fatigue

Chairman: R. Coutant, Progress Energy

10:30 am Corrosion Fatigue – American Electric Power Big Sandy Plant Experience
J. Burton, H. Dillow, D. Mel and **D. Hubbard** (American Electric Power)

10:55 am Research and Service Experience with Environmentally Assisted Cracking of Low-Alloy Steel
J. Hickling (EPRI) and H. Seifert (Paul Scherer Institute, Switzerland)

11:15 am Discussion on Session 3

SESSION 4: Mechanisms #2 – Oxide Growth and Exfoliation

Chairman: R. Coutant, Progress Energy

11:20 am Progress in Prediction and Control of Scale Exfoliation on Superheater and Reheater Alloys
I. Wright and P. Tortorelli (ORNL), M. Schutze (DECHEMA Germany), S. Saunders (NPL), and B. Dooley (EPRI)

11:45 am **Lunch**

1:10 pm Root Cause Identification of Superheater Tube Failures in 9Cr Martenstic Alloys
F. Starr, J. Castle and R. Walker (University of Surrey, England)

1:35 pm Discussion on Session 4

SESSION 5: International Approaches to Tube Failures

Chairman: T. Kirwan, ESB

1:40 pm Impact of De-Regulation on Boiler Tube Failures – A UK Perspective
P. James (Powertech, UK)

2:05 pm The Boiler Life Management Model in the Belgian Power Industry
M. Eyckmans and J. Barthelemi (Laborelec, Belgium)

2:30 pm **Break**

3:00 pm Root Cause Analysis Methodology Applied to Reduce BTF Affecting a Power Station
L. Faria H. (Comision Federal de Electricidad, CFE, Mexico)

3:25 pm Discussion on Session 5

SESSION 6: Welding and Repair Aspects

Chairman: T. Kirwan, ESB

3:30 pm Weld Joint Failure and Success in Reheat Replacement Projects
P. Bailey (Hoosier Energy Rural Electric Cooperative) and Jim Tipperreiter (Welding Services, Inc.)

3:55 pm Alternative Filler Materials for DMWs Involving P91 Materials
K. Coleman, EPRI

4:20 pm Consequences of Poorly Controlled Electric Resistance Welding of Boiler Tubes
G. Smith (Edison Mission, Australia)

4:45 pm Discussion on Session 6

6 - 7:30 pm **Reception and Buffet**
Vendor Exhibition

Wednesday, November 3, 2004

7:00 am Continental Breakfast and Presenter/Session Chairmen Breakfast

SESSION 7: HRSG Tube Failures (HTF)

Chairman: B. Dooley, EPRI

8:00 am Evaluation and Correction of Thermal Transient and Cycle Chemistry Influenced HRSG Tube Failures
B. Dooley and K. Shields (EPRI), **S. Paterson** (Aptech), and M. Pearson (J. Michael Pearson & Associates, Canada)

8:25 am Quantifying Thermal Transients in HRSGs
R. Anderson (Progress Energy) and J. Pearson (Pearson & Associates, Canada)

8:50 am FAC Failures/Chemistry
F. Gabrielli (Alstom Power)

9:15 am Repair Welding Technologies for HRSG Tubing
D. Gandy (EPRI)

9:40 am Discussion on Session 7

9:50 am **Break**

SESSION 8: Mechanisms #3 – Fireside

Chairman: P. James, EON-UK

10:20 am Boiler Tube Erosion Reduction Using the Cold Air Velocity Testing Technique
J. Drennen, Jr. (Drennen Engineering, Inc.) and B. Dooley (EPRI)

10:45 am Circumferential Cracking in Chromized, Water-Touched Tubes
S. French and C. Skelonis (PPL Generation)

11:10 am Discussion on Session 8

SESSION 9: Mechanisms #4. Stainless Steels

Chairman: P. James, EON-UK

11:15 am Variations in the Rupture Strength of Stainless Steel Tubing Based on Solution Annealing Temperature and Nitrogen Content
J. Henry and S. Howard (Alstom Power)

11:40 am EPRI's Guidelines for Assessment of the Remaining Life of Austenitic Stainless Steel Superheater and Reheater Tubing Subject to Long-Term Overheat-Creep
S. Paterson, T. Kuntz and D. Moser (Aptech), D. Gandy, K. Coleman and B. Dooley (EPRI)

12:05 pm Discussion on Session 9

12:10 pm **Lunch**

SESSION 10: Cycle Chemistry Influences on Tube Failures

Chairman: G. Hoffman, PacifiCorp

1:40 pm Xcel Energy Experience with Chemistry-Influenced Boiler Tube Failures
A. Howell (Xcel Energy)

2:05 pm Chemical Cleaning and Steam Generator Tube Failure Prevention
B. Larkin (Black & Veatch) and **K. Shields** (EPRI)

2:30 pm **Break**

3:00 pm Influence of Steam Generator Shutdown, Layup, and Startup Chemistry Control Practices on Steam Generator Tube Failures
K. Shields (EPRI)

3:25 pm Approaches to Minimize Risks of BTF from Manufacturing Until the End of Commissioning
M. Rziha (Siemens, Germany)

3:50 pm Discussion on Session 10

4:00 pm General Conference Discussion

Thursday, November 4, 2004

7:00 am Continental Breakfast and Presenter/Session Chairmen Breakfast

SESSION 11: NDE for Boiler and HRSG Tubing

Chairman: L. McQueen, OPG

8:00 am Long-Range, Guided-Wave Inspection of Reheater Tube Networks in a Boiler
H. Kwun and S. Kim (Southwest Research Institute) S. Walker (EPRI)

8:25 am Detection and Quantification of Damage in Stub Tubes Using Ultrasonic Phased Arrays
L. Nottingham and L. Bisbee (Structural Integrity)

8:50 am Ultrasound Laminographie – A Unique Detection Method for Creep-Deteriorated Material
K. Schmitt-Thomas and **E. Tolksdorf** (Technical University of Munich, Germany)

9:15 am Coordinating NDE Techniques for Examination of HRSGs
S. Walker (EPRI)

9:40 am **Break**

10:10 am Electromagnetic NDE Techniques for Condition Assessment of HRSG
K. Krzywosz (EPRI)

10:35 am Discussion on Session 11

SESSION 12: Remaining Life Techniques

Chairman: D. Gandy, EPRI

10:40 am Financial Risk Optimization: Application Example in Integrated Life Management of a High-Temperature Boiler Tube Component
J. Parker (Structural Integrity)

11:05 am Life Cycle of a Reheater Tube
P. James and J. McMorrow (Powertech, UK)

11:30 am Application of Probabilistic Risk Assessment to High-Temperature Boiler Tube Remaining Life Analysis
R. Coutant Progress Energy)

11:55 am The Use of Risk Based Inspection (RBI) and Warning Level Approaches for Determining Inspection of Boiler Tubing
J. Price and S. Noori (Monash University, Australia), A. Beveridge (Loy Yang Power Station, Australia)

12:20 pm Discussion on Session 12

12:25 pm **Lunch**

SESSION 13: BTF Reduction Programs

Chairman: R. Micko, Entergy

1:50 pm Characteristics of "World Class" Boiler Tube Failure Reduction/Cycle Chemistry Improvement Programs
J. Dimmer and B. Dooley (EPRI)

2:15 pm Hoosier Energy Merom Generating Station's Experience with BTF and Cycle Chemistry Improvement
P. Bailey (Hoosier Energy Rural Electric Cooperative)

2:30 pm Implementation of a Boiler Tube Failure Reduction Program at Progress Energy
R. Coutant (Progress Energy)

2:45 pm What Steps Are Necessary to Obtain a "World Class" Boiler Availability Status
S. Richter (GR Energy)

3:00 pm Discussion on Session 13

3:15 pm **Conference Closure and Final Remarks**

B
CONFERENCE QUESTIONNAIRE AND RESULTS

INTERNATIONAL CONFERENCE ON BOILER TUBE FAILURES AND HRSG TUBE FAILURES, AND INSPECTIONS

November 2-4, 2004

QUESTIONNAIRE

Please complete this questionnaire during the Conference and leave it in the box outside the meeting room. Attendees please complete appropriate sections. If you are involved in the operation of conventional fossil plants, then please complete Sections A-K. If you are involved in the operation of HRSGs, then please complete Sections L to N. All attendees please complete last page.

CONVENTIONAL FOSSIL PLANTS

48 utility organizations responded

A. BOILER TUBE FAILURE STATISTICS AND OVERVIEW

1. Do you know the availability loss for BTF in your organization in 2003? **60%** YES / NO

2. If answer to 1 is yes, what is it? **<1% 14%, 1-2% 12%, >3% 23%**

3. Please rank the five leading BTF mechanisms in your boilers. (e.g. corrosion fatigue, fireside corrosion, flyash erosion, sootblower erosion, longterm overheating/creep, hydrogen damage, acid phosphate corrosion, etc.)

   1. **Flyash erosion**
   2. **Corrosion fatigue**
   3. **Longterm overheating/creep**
   4. **Sootblower erosion**
   5. **Under – deposit corrosion**

4. What is the total cost of BTF / yr in your utility (circle)

22%	**13%**	**8%**	**19%**	**30%**
$ 5M / yr or less	$5-10M / yr	$10-20M / yr	More than $20M / yr	Don't Know

B. BTF DOCUMENTATION

1. Do you record BTF:

   (a) By location ? **90 %** YES / NO

   (b) By failure mechanism ? **83%** YES / NO

   (c) By root cause ? **73%** YES / NO

C. BTF MANAGEMENT SUPPORT AND REDUCTION PROGRAM

1. Do you have an upper management supported BTF Reduction Program? **80%** YES / NO

2. Do you have a BTF Reduction Program Utility-Wide Philosophy Statement? **63%** YES / NO

3. Is the statement signed by senior management? **56%** YES / NO

4. What is the main goal of your program? (**43%** Availability loss due to BTF, minimize BTF, number of BTF/unit/year, reduce cost/yr)

5. Do you have BTF reduction team(s) at each plant **46%** YES / NO

6. Are they multidisciplinary (operations, maintenance) **54%** YES / NO

7. How often are your BTF staff trained in BTF? (circle)

16%	**52%**	**21%**
Every Year or Less	Every Two Years or More	Never

8. How often are your operators trained in BTF? (circle)

4%	**42%**	**44%**
Every year or less	Every two years or More	Never

D. WATERWALL NDE THICKNESS SURVEYS

1. Typically, how much time is allocated for a waterwall thickness survey?

25%	**13%**	**40%**	
Less than 12 hours	12-24 hours	1-3 days	More

2. Who performs the measurements?

29%	**25%**	**58%**	
Station staff	Central service staff	NDE company	Other

3. Approximately what percentage of the waterwall is measured?

46%	**23%**	**21%**	**4%**
Less than 5%	5-10%	11-50%	More than 50%

4. What type of measurement campaign is typically conducted?

42%	**48%**
Bands around furnace	Local area spot check

5. What is the primary objective of the inspection?

81%	**15%**
General OD wall loss	ID corrosion pitting

6. What limits the number of thickness measurements made? **(Multiple answers)**

Time allowed	**63%**	Number of trained operators		Access	**52%**
Safety		Tube's surface condition	**40%**	Cost	**44%**
Operator Training		Unreliable results			
Other (explain)					

7. What equipment is used?

UT thickness meter (D-meter) without ultrasonic trace	**60%**
UT thickness meter with ultrasonic trace	**42%**
Ultrasonic flaw detector	**10%**
Electromagnetic Acoustic Transducer (EMAT)	**12%**
Other (explain)	
Do not know	

8. How are thickness measurements recorded?

In equipment's electronic memory for later playback	**42%**
Immediately transferred to another electronic device/software package	**13%**
Written on paper	**42%**
Other (explain)	

E. CHEMICALLY INFLUENCED BTF

1. Do you have chemically influenced BTF ? **75%** YES / NO
(Hydrogen damage, Acid Phosphate Corrosion,
Corrosion Fatigue, Stress Corrosion Cracking, Pitting, etc.)

2. If yes, which ones?

Hydrogen damage 50%, Acid phosphate corrosion 14%, Pitting 16% Corrosion fatigue 26%

3. Do you have management support to shut a unit
down in the event of a major contamination? **65%** YES / NO **23%**

4. What is the boiler water chemistry on your drum units (circle):

30%	**14%**	**46%**	**2%**	**17%**	**19%**
EPT	PC	AVT	CT	OT	DON'T KNOW

5. Do you provide protection to boiler during
shutdown (nitrogen blanket, reducing agent, etc.) **44%** YES / NO **46%**

F. HYDROGEN DAMAGE (HD)

1. Have any of your units experienced HD in the last 5 years? **50%** YES / NO **38%**
(If No, go to Section G)

2. What was the initiating (root) cause? (circle)

25%	**79%**
acid ingress from make-up demineralizers	condenser leaks

Others: _____

3. Was unit shutdown immediately after contamination? YES / NO **92%**

4. Was unit chemically cleaned after contamination? **50%** YES / NO **50%**

5. Was NDE performed to determine extent? **71%** YES / NO

6. What NDE technique was used? (circle)

38%	**33%**	
UT (velocity technique)	UT (sound attenuation)	Radiography
EMAT	Eddy Current	

7. Do you consider the NDE successful at:

   a) detecting HD **54%** YES / NO

   b) gaging the extent of HD **42%** YES / NO

8. Are you satisfied with currently available:

   (a) Understanding of HD **83%** YES / NO

   (b) Techniques to overcome HD **71%** YES / NO

   (c) NDE Procedures to identify HD areas **50%** YES / NO

G. <u>CORROSION FATIGUE</u> (CF) <u>in the Waterwalls/Economizers</u>

1. Have any of your units experienced CF in last five years? **56%** YES / NO
   (If No, go to Section H)

2. Which boiler locations are/were affected:

89%	**56%**	**67%**	**59%**	**26%**
Windbox Attachments	Seal plate	Scallop bars	Membranes	Slope tubes
67%	**11%**			
End of Membranes	Roof tubes			

Others _____

3. What is boiler water chemistry on units with CF (circle)

30%	**26%**	**41%**	**0%**		
EPT	PC	AVT	CT	OT	Not Known

4. Do the units experience boiler water pH depressions on shutdown and startup? **33%/ 22%/37%** YES / NO / DON'T KNOW

5. What chemicals have been used to chemically clean the affected boiler:

48%	**26%**	**78%**		
HCl	Citric	EDTA	Other	Not Known

6. What NDE technique was used to determine locations (circle):

30%	**15%**	**74%**
UT	Radiography	Visual/Optics

7. Do you consider the NDE successful at:

   a) detecting CF **30%** YES / NO **70%**

   b) gaging the extent of CF **3%** YES / NO **88%**

8. Are you satisfied with currently available:

   (a) Understanding of CF **55%** YES / NO **44%**

   (b) Techniques/Solutions to overcome CF **15%** YES / NO **85%**

H. <u>FLY ASH EROSION</u> (FAE)

1. Have any of your units experienced FAE in last five years **71%** YES / NO **21%**
   (If No, go to Section I)

2. What areas are affected (circle)

85%	**70%**	**41%**	**41%**	
Economizer	Backpass	Reheat	Superheat	Other_____

3. What techniques have you used to counteract FAE (circle)

35%	**85%**	**18%**	**76%**	**41%**
Solid Baffles	Shields	Coatings	Tube Replacements	Cold Air Velocity Technique

35%
Weld overlays

Others (And/Or Amplify) _____

_____

_____

4. How successfully have these techniques been in preventing repeat failures?

_____

_____

5. Is your utility aware of the benefits of using the cold air velocity technique (circle):

23%	**58%**	**15%**
Not Aware	Aware	Fully Aware

I. DISSIMILAR METAL WELDS (DMW) (between ferritic and austenitic tubing)

1. Have any of your units experienced DMW in last five years **60%** YES / NO
(If No, go to Section J)

2. Have they occurred in

(a) Superheater **93%** YES / NO

(b) Reheater **56%** YES / NO

3. Were the welds made with:

(a) Inconel Filler **62%** YES / NO

(Which Filler? _____)

(b) Austenitic Filler **58%** YES / NO

(c) Induction Pressure Welds **34%** YES / NO

(d) Ferritic Filler **7%** YES / NO

4. What was root cause of DMW failure (circle)

58%	**45%**
Excessive Temperature	Temperature Cycling
24%	
Constrained Thermal Expansion	Other _____

5. How was repair made ? (circle):

17% Straight Replacement

41% Change Weld Material and Geometry

10% Moving Weld to Lower Stress /Temperature Zone

58% Use of "dutchman" (replacement made in the shop)

Other _____

6. Are you satisfied with available solutions? **76%** YES / NO **27%**

7. Do you perform analyses to estimate remaining life of DMW's? **38%** YES / NO **50%**

Which Code do you use:

DMW-PODIS (EPRI) DMW Life (SIA)

J. LONGTERM OVERHEATING / CREEP (LTOC)

1. Have any of your units experienced LTOC in the last five years (If No, go to Section K) **79%** YES / NO **10%**

2. What was the material affected (circle):

13%	**68%**	**76%**	**10%**	**8%**	**20%**
T1	T11	T22	T9	T91	Austenitic

Other _____

3. Was the remaining life of the superheater/reheater determined **80%** YES / NO **13%**

4. What technique was used to assess remaining life (circle - maybe multiple answers):

18% Wall Loss/Corrosion Rate

Uniaxial Testing

Burst Testing

16% Statistical Methods

24% Measuring Temperature with Thermocouples

18% Estimating Temperature Metallographically

86% Oxide Scale Thickness Technique

Other _____

K. WATERWALL FIRESIDE CORROSION (WWFC)

1. Have any of your units experienced WWFC in last five years? (If no, go to last page) **42%** YES / NO **50%**

2. Were the units supercritical ? **45%** YES / NO

3. Were the units drum units? **65%** YES / NO

4. Did WWFC occur after installing Low NOx burners **70%** YES / NO
   Do Low NOx burners have overfire air ports (SOFAs) **65%** YES / NO

5. Did units have WWFC prior to low NOx burners **50%** YES / NO

6. Do you know the maximum corrosion rate **30%** YES / NO **40%**

   What was it (please circle)

   < 20 mils/yr > 20 mils/yr > 50 mils/yr > 100 mils/yr

7. What solution has been applied to overcome WWFC

   - Weld Overlay IN625 **25%**
   - Weld Overlay IN622 **35%**
   - Weld Overlay 309SS **20%**
   - Chromizing
   - Other _____

8. Are you satisfied with current solution(s) **50%** YES/NO

9. Are you assessing weld overlay/coating performance? **60%** YES/NO

   If yes, (circle all that apply)

55%	**25%**	**30%**
NDE – Visual	NDE – Thickness Measurement	Metallurgical Sampling

10. Have you experienced cracking damage on overlays/coatings? **30%** YES/NO **55%**

    If yes, has root cause for cracking been determined (circle)

    Corrosion assisted thermal fatigue Thermal quenching

    Inadequate overlay/coatings

11. What needs to be improved or what R&D needs to be conducted

    _____

HRSG PLANTS

Responses from 20 organizations

L. HRSG Tube Failures

1. What type(s) of HRSG do you operate

   Single pressure **15%**
   Double pressure **30%**
   Triple pressure **75%**
   Cycle including once-through **10%**

2. Have you had any HRSG Tube Failures (HTF)? **60%** YES/NO **25%**

3. Locations of HTF (please circle)?

35%	**20%**	**15%**	
LP Economizer	LP Evaporator	IP Economizer	IP Evaporator
15%	**15%**	**15%**	
HP Economizer	HP Evaporator	Superheater	Reheater

4. Types of Failure Mechanism (please circle)?

35%			
FAC	Hydrogen Damage	Caustic Gouging	Acid Phosphate Corrosion
15%		**20%**	
Corrosion Fatigue	Thermal Fatigue	Pitting	Longterm Overheating

   Creep-Fatigue

5. What chemical treatment do you use on LP Drum?

35%				
AVT	EPT	PC	CT	OT

6. What chemical treatment do you use on IP Drum?

   AVT EPT PC CT OT

7. What chemical treatment do you use on HP Drum?

   AVT EPT PC CT

8. Did you preoperationally clean HRSG? YES/NO

9. Have you operationally cleaned HRSG? YES/NO

M. HRSG NDE Practices

1. Do you perform tubing NDE?

   During planned outages? **60%** YES/NO

   During forced ourages? **30%** YES/NO

2. What NDE techniques are used (circle all that apply)

Visual of OD **65%**
Visual of ID (videoprobe/boroscope) **45%**
UT Thickness Measurements **55%**
UT ID Oxide Thickness Measurements **10%**
Radiography **15%**
Other _____ (list)

3. Are you satisfied with NDE techniques for HTSGs? **30%** YES/NO **35%**

4. What needs to be improved or research to be Conducted for NDE?

Finned Tubes

N. Thermal Transients on HRSGs

1. Have you installed thermocouples and monitored HRSG circuits? **30%** YES/NO **35%**

If yes, please circle those monitored

	10%		
LP Economizer	LP Evaporator	IP Economizer	IP Evaporator
	15%	**20%**	**20%**
HP Economizer	HP Evaporator	Superheater	Reheater

2. Have you changed the drain connections on any HRSG circuits? **10%** YES/NO **50%**

If yes, please circle those changed

LP Economizer	LP Evaporator	IP Economizer	IP Evaporator
HP Economizer	HP Evaporator	Superheater	Reheater

3. Have you experienced any thermal shock from attemperators? **20%** YES/NO **45%**

All Attendees Please Answer these questions about the Conference and future EPRI R&D.

Responses from 61 conference attendees

1. What do you consider as the highest priority in BTF/HTF reduction?

Training and education in BTFRP/CCIP with emphasis for management. Corrosion fatigue and corrosion fatigue NDE

2. What priority (low, high, urgent) would you give to the following BTF/HTF areas (please add others)in terms of needed future research (circle):

• Developing more consistently reliable NDE techniques for hydrogen damage	**44%/42%/10%** L / H / U
• Developing solutions for corrosion fatigue in conventional and HRSG plants	**21%/43%/36%** L / H / U
• Developing an NDE technique for corrosion fatigue in conventional plants	**6%/44%/46%** L / H / U
• Developing solutions for waterwall fireside corrosion	**54%/28%/10%** L / H / U
• Development of NDE techniques for HRSGs	**31%/44%/11%** L / H / U
• _____	_____
• _____	_____

Name _____

Organization _____

Telephone _____

E-Mail _____

C
CONFERENCE PARTICIPANTS

Attendees

CONF-Boiler Tube Failures & HRSG Tube Failures Conference 2004

11/2/2004 through 11/4/2004

Company	Registrants
ALSTOM (Switzerland) Ltd.	Gabrielli,Frank
	Arnold,John L.
	Howard,Shari
American Electric Power Service Corp.	Guttner,George
	Hubbard,Douglas Edward
APTECH Engineering Services, Inc.	Paterson,Steve R.
ATCO Power Canada, Ltd.	Lindbeck,Dan
Automation Technology, Inc.	Freeman,Matt
BJ Process & Pipeline Services	Barber,Steven J.
Comision Federal de Electricidad (CFE)	Farias,Luis H.
Constellation Energy Group, Inc.	Bonnington,Alex
CPS Energy	Sanjuan,Mario
	Ellis,James M.
Dairyland Power Cooperative	Henkelman,John
DBA John Dimmer	Dimmer,John
Deltak, LLC	Albert,Pat
Detroit Edison Co.	Jenkins,Roger D.
	Lynch,Richard J.
Drennen Engineering, Inc.	Drennen Jr.,John F.
Duke Energy Corp.	Walsh,Bryan Patrick
Dynegy Midwest Generation, Inc.	Carson,Bill G.
E.ON U.S.	Fuller,Chris
	Rupinen,Michael
E.ON UK Ltd.	James,Paul

Attendees

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11/2/2004 through 11/4/2004

Company	Registrants
Edison Mission O&M Loy Yang Pty.,	Smith,Garry
Electrabel N.V.	Valckenborgh,Robert
Electric Power Research Institute (EPRI)	Shields,Kevin
	Hickling,John
	Dooley,Barry R.
Entergy Corporation	Jaskot,Stanley M.
	Micko,Richard E.
EPCOR	Whitten,David C.
EPRI Charlotte Office	McCalla,Jimmy
	Krzywosz,Kenji J.
	Walker,Stan M.
	Tilley,Richard
	Coleman,Kent
ESB Electricity Supply Board of Ireland	Gallagher,Ciaran
	Hodgins,Joe
	Kirwan,Tony
	Scully,Stephen
ESKOM	Serekwa,Lebo
	Tarr,Russell Egan
European Technology Development, Ltd.	Starr,Fred
Everest Sales, Inc.	Lordy,Ken
FirstEnergy Service Co.	Waddingham,Alan L.
Genesis Power, Ltd.	Hopkins,Keith Norman
Great River Energy	Richter,Steve Joseph
Hawaiian Electric Co., Inc.	McCraw,William E.
Hoosier Energy Rural Electric Coop., Inc	Bailey,Phillip Allen

Attendees

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11/2/2004 through 11/4/2004

Company	Registrants
IMI Vision/CCI	Straate,Russ
	Sherikar,Sanjay V.
J. Michael Pearson & Assoc. Co., Ltd.	Pearson,J. Michael
Korea Electric Power Research Institute	Jung,Jine-Sung
	Kim,Beom Soo
Kurita Water Industries Ltd.	Satou,Takatoshi
	Takahashi,Junichi
Laborelec	Eyckmans,Marc
	Barthelemi,Jean-Pier
M&M Engineering	Munson,Ronald
Margan, Inc.	Ezra,Dan
MidAmerican Energy Co.	Wiegand,James D.
Mitsubishi Heavy Industries, Ltd.	Matsumoto,Hirotoshi
Monash University	Price,John W. H.
Moscow Power Institute	Petrova,Tamara
Nooter/Ericksen	Schroeder,Joseph
NRG Texas, LLC	Shin,Stephen
Oak Ridge National Laboratory	Wright,Ian G.
Omaha Public Power District	Bley,Steven
Ontario Power Generation, Inc.	McQueen,Robert Lyle
PacifiCorp (PC)	Pinterich,Glenn
	Blessing,Stuart "Stu"
	Metzler,Craig
	Hoffman,Gary L.
Petrobras Energia S.A.	Perez,Jose Horacio

Attendees

CONF-Boiler Tube Failures & HRSG Tube Failures Conference 2004

11/2/2004 through 11/4/2004

Company	Registrants
PIC Energy Group	Lentzer,Paul
	Adams,Brad
Pinnacle West Energy	Yarbrough,Mark Edward
PPL Generation, LLC	French,Stephen M
Progress Energy, Inc.	Catsikopoulos,Bill
	Coutant,Richard Alan
	Le,Hue C.
Reliant Resources	Wohleber,David O.
RWE Npower plc	Johnston,Chris
Siemens AG	Rziha,Michael
South Carolina Electric & Gas Co.	Bidwell,Paul G.
	Eargle,George
Southern Company	Richey,Billi Jo
Southern Company Services, Inc.	Ladner,Nathan D.
Southwest Research Institute	Kwun,Hegeon
Special D Events, Inc.	Jackman,Tina
	Galle,Carol
Stress Engineering Services	Frey,Joe
	Wernecke,Kris
Structural Integrity Associates, Inc.	Dowling,Matt
	Bisbee,Laney H.
	Parker,Jonathan
Tarong Energy Corp., Ltd.	Vorpagel,Russell
	Reidy,David
Technical University Munich	Tolksdorf,Erich

Attendees

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11/2/2004 through 11/4/2004

Company	Registrants
Tenaga Tiub Son BHD	Joon,Yeng Fook
The Hongkong Electric Co., Ltd.	Choi,H. K.
Thermtech Services	Reilly,Tom
TransAlta Centrallia Generation, LLC	Berner,David
	Lee,Seon-Uk
TransAlta Utilities Corp.	Shewchuk,Rick
Triple 5 Industries	McGurkin,Megan
TXU Electric	Fincher,Scott
TXU Power	Hardin,Tony
U.S. Filter	Loken,Robert G.
	Ogle,Jeff
Welding Services, Inc.	Tipperreiter,Jim
Xcel Energy Services, Inc.	Howell,Andrew

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Together...Shaping the Future of Electricity

Programs:

Boiler Life and Availability Improvement Program

Heat Recovery Steam Generator (HRSG) Dependability

1013629

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